# Comments on Consumers Energy's *Electric Generation Alternatives Analysis* for the Balanced Energy Initiative including the Proposed Karn-Weadock Coal Plant

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## SUMMARY OF COMMENTS

1. Our review has been limited due to Consumers Energy's failure to provide many source documents and analyses and its computer modeling files. Furthermore, our review has been limited because of the very short 30 day period in which we have had to review the EGAA and draft these comments without the opportunity for discovery.

2. It is unclear whether the Company's forecasts of future loads and energy requirements, which were prepared last fall, adequately reflect the current economic situation.

3. 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 Karn-Weadock coal plant.

4. The EGAA increases the apparent need for the Karn-Weadock plant in 2017 by assuming that Consumers Energy will not be able to achieve more than 0.5 percent annual incremental energy efficiency savings after the year 2015.

5. Consumers Energy assumes in the EGAA that it will not add any additional renewable resources after 2018.

6. The only way that Consumers Energy can show a need in 2017 in the EGAA for its proposed Karn-Weadock plant is by suggesting that it will retire approximately 950 MW of existing coal capacity by 2018 even though it has not made any firm commitment to actually retire any or all of that capacity. In fact, an increasing amount of the Company's aging coal-fired generating plants can be retired over time without building the proposed Karn-Weadock plant.

7. The EGAA understates Consumers Energy's continuing heavy dependence on coal-fired generation in future years by (a) presenting capacity mix information in MW instead of MWh and (b) by suggesting that the Company will retire approximately 950 MW of existing coal capacity by 2018 when it has not made any firm commitment to actually retire that capacity.

8. A comprehensive system for federal regulation of carbon dioxide ($CO_2$) and other greenhouse gas emissions is inevitable. It is generally expected that this federal regulation will require steep reductions in greenhouse gas emissions.

9. 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.

10. If it operates at an average annual 85 percent capacity factor, the proposed 830 MW Karn-Weadock plant will emit 5.8 million tons of $CO_2$ each year for an estimated 60 year operating life. There currently is no commercially viable technology for capturing $CO_2$ emissions from pulverized coal plants and significant uncertainty as to whether and when that technology will become viable. The claim that the plant will be “carbon capture ready” has no real substantive meaning but, instead, essentially suggests only that space has been set aside to accommodate currently unknown equipment for capturing $CO_2$ that would otherwise be emitted into the atmosphere.

11. Ratepayers will face significant financial risk associated with the decision to lock in high levels of carbon emissions for the coming decades at a time when those emissions will be costly.

12. The estimated cost of the proposed Karn-Weadock coal plant has increased by 32 percent since the Company filed its original Balanced Energy Initiative in 2007. The plant’s cost may increase further before it is completed.

13. The EGAA does not consider the risks associated with different supply and demand side plans. In fact, other than considering levelized costs for resources with and without $CO_2$ costs, the EGAA did not consider uncertainty for any of the key input parameters.

14. The levelized cost analyses in the EGAA did not adequately consider portfolios of alternatives to the proposed Karn-Weadock coal plant that would include existing and/or new gas, more wind, and additional cost-effective energy efficiency.

15. The use of unreasonably high natural gas prices biases the levelized cost analyses in the EGAA in favor of coal.

16. The use of high coal plant and extremely low natural gas plant capacity factors biases the levelized cost analyses in the EGAA in favor of coal.

17. The levelized cost analyses in the EGAA are biased in favor of coal by the unrealistic assumption that all of the alternatives considered were in service as of the beginning of 2009.

18. The use of very high wind costs biases the levelized cost analyses in the EGAA in favor of coal.

19. Uncertainty over construction costs and the costs of complying with future federal carbon dioxide emission reduction requirements has, 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 limited due to Consumers Energy's failure to provide many source documents and analyses and its computer modeling files. Furthermore, our review has been limited because of the very short 30 day period in which we have had to review the EGAA and draft these comments without the opportunity for discovery.**

The Company has failed to provide the many source documents, analyses and computer modeling files which form the basis for many of the conclusions presented in EGAA. As a result, we are unable to verify many of the claims and conclusions presented in the EGAA, especially the results that come from Consumers Energy's modeling analyses; for example, the annual coal system energy and $CO_2$ emissions numbers presented in Figure 10 and Table 4. Without the modeling input and output files, we are unable to determine which assumptions Consumers Energy made in these modeling analyses and whether those assumptions are appropriate in light of current and expected future circumstances.

Our assessment also has been limited due to the extremely short 30 day period in which we have had to review the EGAA, without any opportunity for discovery, and to draft these comments.

**2. It is unclear whether the Company's forecasts of future loads and energy requirements, which were prepared last fall, adequately reflect the current economic situation.**

The load and energy requirement forecasts used in the EGAA were developed last year and presented by the Company in its November 2008 testimony in Case No. U-15645.[1] These forecasts projected growth in loads and energy requirements from 2009 forward. There have been significant economic developments since November 2008 that raise doubts about whether the Company's load and energy requirements will increase in the near term and whether the forecasts that were presented in Case No. U-15645 remain reasonable at this time. For example:

- Electric generation by utilities in Michigan dropped by 13.5 percent between the first quarter of 2008 and the first quarter of 2009.[2]
- The state has experienced multiple economic shocks including the proposed closing of a significant number of auto production plants.
- The Michigan Public Service Commission staff has noted that Consumers Energy anticipates a 4.5 percent decline in sales in 2009 and that total electric sales for the state are projected to decline by 6.7 percent.[3]

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1 EGAA, Footnote No. 11, at page 7.

2 http://www.eia.doe.gov/cneaf/electricity/epm/table1_6_b.html

- The Company filed Rebuttal Testimony in Case No. U-15645, noting that based on the Energy Appraisal report, "we may see a substantial decline from our forecast."[4]

An analysis of need should be based on the most current and reliable forecasts of loads, energy requirements and resources. Before the conclusions of the EGAA are accepted, Consumers Energy should be required to update its 2008 load and energy requirement forecasts to reflect a more timely assessment of current and projected economic conditions.[5]

**3. 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 Karn-Weadock coal plant.**

There is a substantial amount of under-utilized natural gas-fired generating capacity both in Consumers Energy's service territory specifically, and in Michigan and neighboring states more generally. 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.[6] 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, especially if unnecessary new coal capacity is built.

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3 *Michigan Energy Appraisal: Semiannual Projections of Energy Supply and Demand, Summer Outlook 2009,* at page 2.

4 Rebuttal Testimony of Lincoln D. Warriner, Case No. U-15645, May 18, 2009, at page 5, lines 18-20.

5 And intervenor parties should be provided a reasonable opportunity to review all such updates.

6 EGAA, 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-1: Natural Gas-Fired Generating Units in Michigan, Ohio and Indiana – 2008 Capacity Factors.**

Consumers Energy states in the EGAA that combined cycle technology "has also demonstrated very high availabilities generally in the low 90 percent range."[7] Before its Alternatives Analysis is accepted, Consumers Energy should be required to demonstrate that producing additional energy at its existing gas-fired facilities is not a cost-effective alternative to the proposed Karn-Weadock plant. The Company 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.

## 4. The EGAA increases the apparent need for the Karn-Weadock plant in 2017 by assuming that Consumers Energy will not be able to achieve more than 0.5 percent incremental annual energy efficiency savings after the year 2015.

Consumers Energy inflates the need for any new capacity from the proposed Karn-Weadock coal plant by arbitrarily reducing its projected incremental annual energy efficiency savings from 1 percent in 2015 to 0.5 percent in 2016 and subsequent years.[8] This is based on the Company's assertion that a cumulative 7.6 percent of retail peak load reductions by 2030 is a reasonable level to assume for planning purposes.[9] The Company also assumes that no additional AMI-Demand Response peak load reductions can be achieved after 2016 and that only

[7] EGAA, at page 31.

[8] EGAA, at page 8.

[9] Id.

extremely minor AMI-Load Management peak load reductions (30 MW over 10 years) can be achieved after 2020. However, Consumers Energy's projected energy efficiency savings (both in MWhs and MWs) are overly conservative for a number of reasons:

(1) Consumers Energy 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, both investor-owned and public, Consumers Energy has not prepared a company-specific energy efficiency potential study for its own service territory. Therefore, it has no evidentiary basis for concluding that it cannot achieve higher energy efficiency savings after 2015.

(2) The Company similarly provided no assessment of the potential for Combined Heat and Power ("CHP") either in its service territory or the state as a whole. Thus, it has no basis on which it can conclude that CHP could be a significant part of a portfolio of alternatives to the proposed Karn-Weadock coal plant.

(3) The EGAA itself notes that energy efficiency has a levelized cost, on average, of only $35 per MWh.[10] This average cost is substantially less than the levelized costs of the coal and natural gas supply side options presented in Table 7 of the EGAA. Given this very low average cost, 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 the $97/MWh to $133/MWh that the Company projects for the cost of the proposed Karn-Weadock coal plant. Consumers Energy should be required to include these lower cost energy efficiency savings before the Company is allowed to build the more expensive Karn-Weadock coal plant.

(4) Evidence presented in docket number U-15805 supports the conclusion that Consumers can achieve substantially greater energy savings than it proposes to capture during the 2009-2014 timeframe and more than it projects for the post -2015 timeframe. In its June 25, 2009 *Filing Regarding a Proposed Financial Incentive Mechanism, Consumers Energy* explained that a revenue decoupling mechanism coupled with a financial incentive that afforded them the maximum statutorily allowed incentive for achieving 120% of the savings target while maintaining a cost/benefit ratio of 3.5 would be sufficiently motivating for the company to exceed the statutory targets.[11] If the Company can exceed its planned energy savings by 20% while maintaining a benefit cost ratio of 3.5, the available cost-effective energy efficiency potential with a savings to cost

[10] EGAA, Table 7, at pages 36 and 37.

[11] *Consumers Energy Filing Regarding a Proposed Financial Incentive Mechanism*, Case No. U-15805, June 25, 2009, page 2, second full paragraph.

ratio of greater than 1 is substantially greater than 20% above the statutorily mandated targets that Consumers intends to meet but not exceed in the 2009-2014 timeframe.

In fact, throughout the proceeding in Case No. U-15805, Consumers objected to capturing additional cost-effective energy savings only on the grounds that in the absence of a decoupling mechanism, saving energy would erode the Company's earnings. NRDC and MEC estimated that by simply spending up to the statutory spending caps (note that Consumers may spend above the statutory spending caps to capture cost-effective energy efficiency potential with the Commission's permission under section 95 P.A. 295), Consumers could save its customers an additional $217 million dollars net of program costs.[12] When pressed to justify Consumers Energy's failure to pursue all cost effective energy efficiency, Company witness Terrence Mierzwa responded that:

- "…the company has no business reason to exceed statutory energy savings targets."
- "…the company is not interested in achieving energy savings above its statutory requirements…"
- "…expenditures above the filed EO plan must await adoption of appropriate revenue decoupling and incentive mechanisms."[13]

(5) 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[14]), Florida (1.3% achievable[15]), Texas (1.2% achievable[16]), and Vermont (1.9% achievable[17]).

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12 Docket No. U-15805, Initial Brief by the Michigan Environmental Council, Ecology Center, Natural Resources Defense Council and Environmental Law and Policy Center, April 28, 2009, at p. 56.

13 Case No. U-15805, Transcript at pages 842 and 850.

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

(6) The 0.5 percent annual energy efficiency savings that Consumers Energy projects for 2016 and later years is substantially below the 2 percent annual savings that the Midwest Governors Association has set as its target.[18]

(7) As discussed in Attachment No. 1 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 Consumers Energy's assumed energy efficiency savings reflect these aggressive actions.

(8) As discussed in Attachment No. 2 to these Comments on Consumers Energy's EGAA, the EPRI study on which the Company seeks to rely is flawed and, consequently, understates the potential for energy efficiency savings.

In conclusion, the Company's assumption that it will be able to achieve only 0.5 percent incremental annual energy efficiency savings starting in 2016 is unsupported and should not be accepted. Instead, the Company should be required to undertake and present the results of a company-specific assessment of the potential for cost-effective energy efficiency before it is granted a permit for the Karn-Weadock coal plant and to update the need assessment in the EGAA to reflect the results of this company-specific assessment.

**5. Consumers Energy assumes in the EGAA that it will not add any additional renewable resources after 2018.**

The EGAA states that "the company has not incorporated additional wind capacity above its proposed renewable energy plan of 900 MW due to the high cost of this capacity, its intermittent and unpredictable nature, and the potential need for back-up capacity."[19] However, none of these claims is persuasive as a reason for limiting the amount of wind that Consumers could economically and reliably add to 900 MW.

First, the claim that more wind cannot be added due to its "intermittent and unpredictable nature and the potential need for back-up capacity" is based on

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

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

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

18 *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.

19 At page 9.

outdated beliefs about the difficulties of incorporating large amounts of wind capacity and energy in a large grid such as the Midwest ISO. Instead, 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 generation facility. At the same time, the effects of short term wind variability can be mitigated by building a larger number of wind turbines and by siting the turbines in different geographic locations.

For example, a 2004 *Wind Integration Study – Final Report* prepared for Xcel Energy and the Minnesota Department of Commerce noted:

> Many of the earlier concerns and issues related to the possible impacts of large wind generation facilities on the transmission grid have been shown to be exaggerated or unfounded by a growing body of research studies and empirical understanding gained from the installation and operation of over 6000 MW of wind generation in the United States.[20]

More recent studies have confirmed these observations. See, for example, the December 2005 and December 2007 issues of *Power & Energy*, published by the Power Engineering Society of the IEEE, and a summary of *Utility Wind Integration State of the Art*, prepared by the Utility Wind Integration Group in cooperation with the American Public Power Association, the Edison Electric Institute, and the National Rural Electric Cooperative Association in May 2006.[21]

The Company's concern that backup capacity would be required for new wind resources ignores the fact, as discussed above, that Consumers Energy already has a significant amount of under-utilized dispatchable gas-fired generating capacity, as does the overall Midwest ISO grid. Before it is allowed to assume that adding new wind resources will be require the addition of backup gas capacity, Consumers Energy should be required to demonstrate that the existing dispatchable capacity will not be adequate.

In its transmission planning analyses, the Midwest ISO is considering scenarios in which its system would have to be able to integrate enough wind to produce at least 20 percent of its total energy needs starting in 2020.[22] In contrast, if Consumers Energy adds only the 900 MW of wind that it currently included in the Balanced Energy Initiative, it will only be generating 5.4 percent of its total energy requirements from wind resources in 2018, and this percentage will

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20 *Wind Integration Study – Final Report*, prepared for Xcel Energy and the Minnesota Department of Commerce by EnerNex Corporation and Wind Logics, Inc, dated September 28, 2004.

21 Available at www.uwig.org.

22 *MTEP08, Midwest ISO Transmission Expansion Plan 2008,* at page 96.

decrease slightly over time to 5.2 percent in 2030.[23] As a U.S. Department of Energy report indicates, this is a smaller percentage of its overall energy requirements than other large utilities such as Xcel Energy and Public Service Company of New Mexico actually generated from wind in 2007.

In fact, there appears to be the potential for very significant amounts of on-shore and off-shore wind in Michigan. A recent proposed draft report for the Michigan Wind Energy Resource Zone Board has estimated that four regions of the state have the potential for between 3,431 MW and 6,140 MW of on-shore wind capacity.[24] Other studies have suggested that there is the potential for as much as 25,000 MW of off-shore wind in the state.[25]

**6. The only way that Consumers Energy can show a need in 2017 in the EGAA for its proposed Karn-Weadock plant is by suggesting that it will retire approximately 950 MW of existing coal capacity by 2018 even though it has not made any firm commitment to actually retire any or all of that capacity. In fact, an increasing amount of the Company's aging coal-fired generating plants can be retired over time without building the proposed Karn-Weadock plant.**

Consumers Energy claims that it needs the capacity from its proposed Karn-Weadock plant to avoid capacity shortfalls predicted for 2018 and subsequent years. However, the capacity shortfalls the Company says it would experience even with a 519 MW share of the proposed coal plant reflect the retirement of some 950 MW of existing coal capacity.[26] Without these retirements, the Company does not have any capacity shortfalls until the Palisades PPA is assumed to end in 2022, even when it assumes that it will only be able to achieve incremental annual energy efficiency savings of 0.5 percent after 2015 and that it will not add any additional renewable resources after 2018.

This can be seen from Table Synapse-2, below, which revises Table 2 from the EGAA to continue operation of the 950 MW of existing coal capacity that Consumers Energy has suggested it may retire at some uncertain time in the future and adds no capacity from the proposed Karn-Weadock coal plant.

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23 These percentages are calculated by dividing the 2,298 GWh of energy projected to be generated each year by the new wind renewable resources, shown in the workpaper for Figure 4 in the EGAA, by the Company's annual total energy requirements, also shown in the same workpaper.

24 *Proposed Report of the Michigan Wind Energy Resource Zone Board*, June 2, 2009, at page 5.

25 Adelaja, S. and C. McKeown, 2008, *Michigan's Offshore Wind Potential, Michigan State Land Policy Institute, September 30, 2008*: *2008 Wind Energy Update,* National Renewable Energy Laboratory, June 2008.

26 EGAA, page 16.

| Year | CECo Capacity Shortfall Assuming No Retirements and No Karn-Weadock |
|---|---|
| 2018 | -212 |
| 2019 | -281 |
| 2020 | -316 |
| 2021 | -333 |
| 2022 | 424 |

**Table Synapse-2: Consumers Energy's Capacity Shortfalls Assuming No Retirements and No Karn-Weadock – EE Savings of 0.5 percent per year after 2015 as projected in the EGAA.**

A negative figure in Table Synapse-2 means that there is a capacity surplus, not a capacity shortfall. Thus, as can be seen from this table, Consumers would not have a need for new generating capacity until 2022 even if all of the Company's claims and assumptions regarding its future loads, the potential for energy efficiency and renewable resources are accepted: unless it retires existing coal capacity, and then only if the Palisades PPA is not renewed or extended. In fact, the results presented in Table Synapse-2 suggest that under these circumstances, the Company actually could retire several hundred MW or more of existing coal capacity and still not have a "capacity shortfall" before 2022, again even if all of the Company's other assumptions about loads and resources are accepted.

As shown in Tables Synapse-3 and Synapse-4, even more coal capacity could be retired if more reasonable assumptions are made about the potential for future energy efficiency savings. The same would be true if the EGAA assumed that additional renewable resources are added, above the 900 MW of wind included in the Balanced Energy Initiative.

| Year | Consumers Energy Capacity Shortfalls Assuming No Retirements and No Karn-Weadock -- 1.0% Annual Energy Savings |
|---|---|
| 2018 | -294 |
| 2019 | -390 |
| 2020 | -452 |
| 2021 | -496 |
| 2022 | 234 |

**Table Synapse-3: Consumers Energy's Capacity Shortfalls Assuming No Retirements and No Karn-Weadock – EE Savings of 1.0 percent per year after 2015.**

| Year | Consumers Energy Capacity Shortfalls Assuming No Retirements and No Karn-Weadock -- 1.5% Annual EE Savings |
|---|---|
| 2018 | -376 |
| 2019 | -499 |
| 2020 | -588 |
| 2021 | -659 |
| 2022 | 44 |

**Table Synapse-4: Consumers Energy's Capacity Shortfalls Assuming No Retirements and No Karn-Weadock – EE Savings of 1.5 percent per year after 2015.**

Consequently, adding more energy efficiency can be an effective strategy for retiring the company's aging coal-fired power plants and for reducing its greenhouse gas emissions. Adding renewable wind resources in addition to the extra energy efficiency would be even more effective in allowing the retirement of existing coal-fired capacity.

However, it must be emphasized that, as it acknowledges throughout the EGAA, the Company has made no commitment, or even has actual plans, for retiring any of its existing coal plants:

> While the Company's older units have been well maintained and no specific plans have been made to retire any of the current fleet, increasingly stringent environmental regulations and the cost of maintaining aging equipment could render these plants uneconomic over the coming decade. As depicted in the declining light blue segment [in Figure 2], the BEI assumes retirement of the company's oldest units (with an average age of over 53 years) in the 2015 to 2018 timeframe.[27]

[27] Consumers Energy EGAA, at pages 11 to 12.

> Longer term, depending on actual load growth trends and actual experience with demand reduction and renewables programs, the company will maintain flexibility and continue to evaluate the economics of extending the life of existing units, extending long-term contracts, and/or building additional generation to fill the gap.[28]

> Eventually replacing several of the company's older, less efficient plants with an advanced pulverized coal plant….[29]

In fact, the Company suggests that under some circumstances both its existing and its proposed new coal plants will be needed.[30]

**7. The EGAA understates Consumers Energy's continuing heavy dependence on coal-fired generation in future years by (a) presenting capacity mix information in MW instead of MWh and (b) by suggesting that the Company will retire approximately 950 MW of existing coal capacity by 2018 when it has not made any firm commitment to actually retire that capacity.**

At pages one and six of the EGAA, Consumers Energy claims that "almost two-thirds of the company's resource additions through 2018 will be provided by new renewable resources, as well as peak load reductions from new energy efficiency and demand management programs." The evidence used to support this claim is a pie chart titled "Resource Additions 2008-2018."[31]

Unfortunately, this figure is based on the MWs of capacity that would be provided by each of the four alternatives presented: Gas Combined Cycle, Renewables, Clean Coal, and Energy Efficiency and Demand Management. However, when considering a company's generation mix, the appropriate way to evaluate the fuel or supply diversity of its facilities is to look at the MWhs of energy provided by each addition or resource type, not the MWs of capacity provided by the resource. This is because the issue of supply diversity is a matter of the amount of fuel that the company burns, and the cost consequences of burning that fuel. Simply looking at its capacity mix, in terms of MWs, does not offer any information about the utilization of that capacity.

If Figure 1 had reflected the MWhs of each of the four alternatives that Consumers Energy says are being added as part of the BEI, the contribution from the proposed Karn-Weadock plant would have been much higher than the 18 percent shown in the pie chart for the "Clean Coal" facility. This can be seen from Figure Synapse-1 below, which presents the MWh of new generation that

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28 Id, at page 14.

29 Id, at page 40.

30 Id, at page 15.

31 At page 6, this pie chart is designated as Figure 1.

would be provided in 2018 by each of the four alternatives presented by Consumers Energy in its Figure 1:

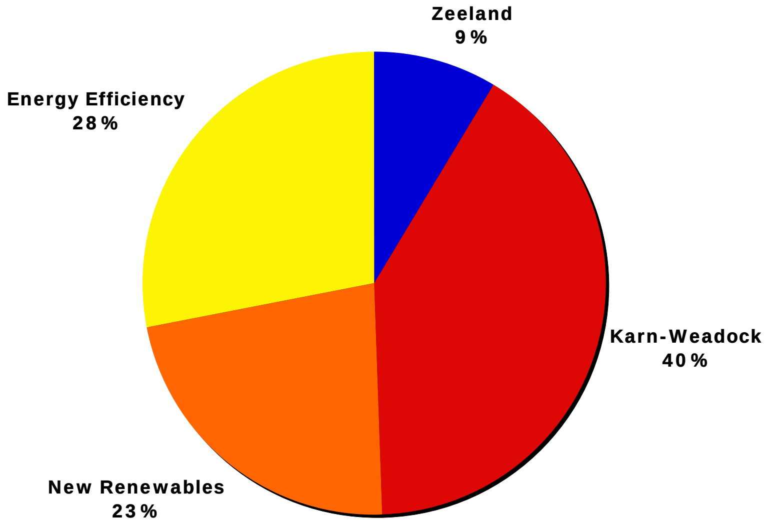


**Figure Synapse-1: Supply Diversity of Proposed BEI Resource Additions by MWhs**

Thus, based on the annual energy numbers presented by Consumers Energy, that we have been unable to verify, the Karn-Weadock coal plant will generate forty percent of the total energy that would be provided in 2018 by the new additions through the BEI.[32] This is more than double the 18 percent contribution that Consumers Energy claims in the EGAA.

In Figure 8 of the EGAA, Consumers Energy presents its Projected Resource Mix for 2018. However, as with Figure 1 in the EGAA, the information in this mix is based on the MWs of each supply and demand side alternative, and not on the MWhs. Thus, the information overstates the contributions from renewable resources and the demand side alternatives and understates the contribution from fossil alternatives. Unfortunately, Consumers Energy does not provide the annual energy emissions from its individual units or by fuel type, so we are unable to prepare a substitute for Figure 8 in the EGAA that shows what the Company's proposed resource mix would be based on the MWhs generated by each fuel and resource type. However, it is clear that the contribution from coal-fired plants will be significantly higher than the 24 percent shown in Figure 8 of the EGAA.

[32] The information on the annual energy contributions from each of the four alternatives shown in Figure Synapse 1 is taken from Consumer Energy's workpaper for Figure 4 in the EGAA.

Moreover, Figure 8 of the EGAA also misrepresents Consumers Energy's likely Capacity Fuel Mix in 2018, even if you consider MWs not MWhs, because it reflects the retirement of 950 MW of existing coal capacity as well as the addition of the alternatives included in the Company's BEI.

Figure Synapse-2 below, presents what the Company's resource mix would be in 2018, by MWs of capacity, if it adds the proposed BEI resources but does not retire any of the 950 MW of existing coal capacity that it suggests, but does not commit to, retiring.[33]

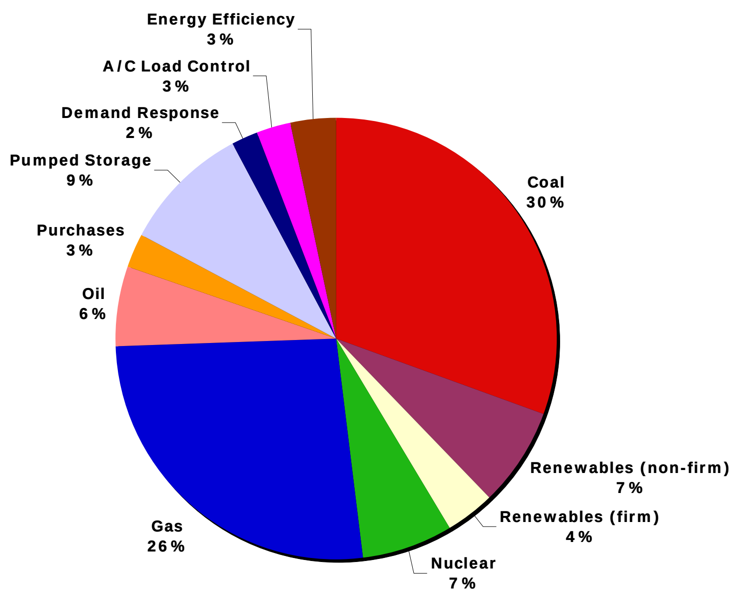


**Figure Synapse-2:** **Consumers Energy's 2018 Resource Mix by MWs, No Coal Plant Retirements**

Thus, even if just the MWs of capacity are considered, coal will represent 30 percent of Consumers Energy's fuel mix in 2018, and fossil-fired capacity will represent more than 60 percent of its fuel mix. Again, the coal clearly would represent a significantly higher percentage of the Company's fuel mix in 2018, and subsequent years, if information on the MWhs of generation by fuel type were available.

33 Figure Synapse-2 is based on the MW capacity figures provided by Consumers Energy as the workpaper for Figure 8 in the EGAA.

**8. A comprehensive system for federal regulation of carbon dioxide ($CO_2$) and other greenhouse gas emissions is inevitable. It is generally expected that this federal regulation will require steep reductions in greenhouse gas emissions.**

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"[34]

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.[35]

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.[36]

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

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

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

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

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-3, below, shows the emissions trajectories that would be mandated under the proposed Waxman-Markey legislation. These trajectories aim for emissions reductions of 83 percent from 2005 levels by 2050, similar to the plan recently announced by the Obama Administration.

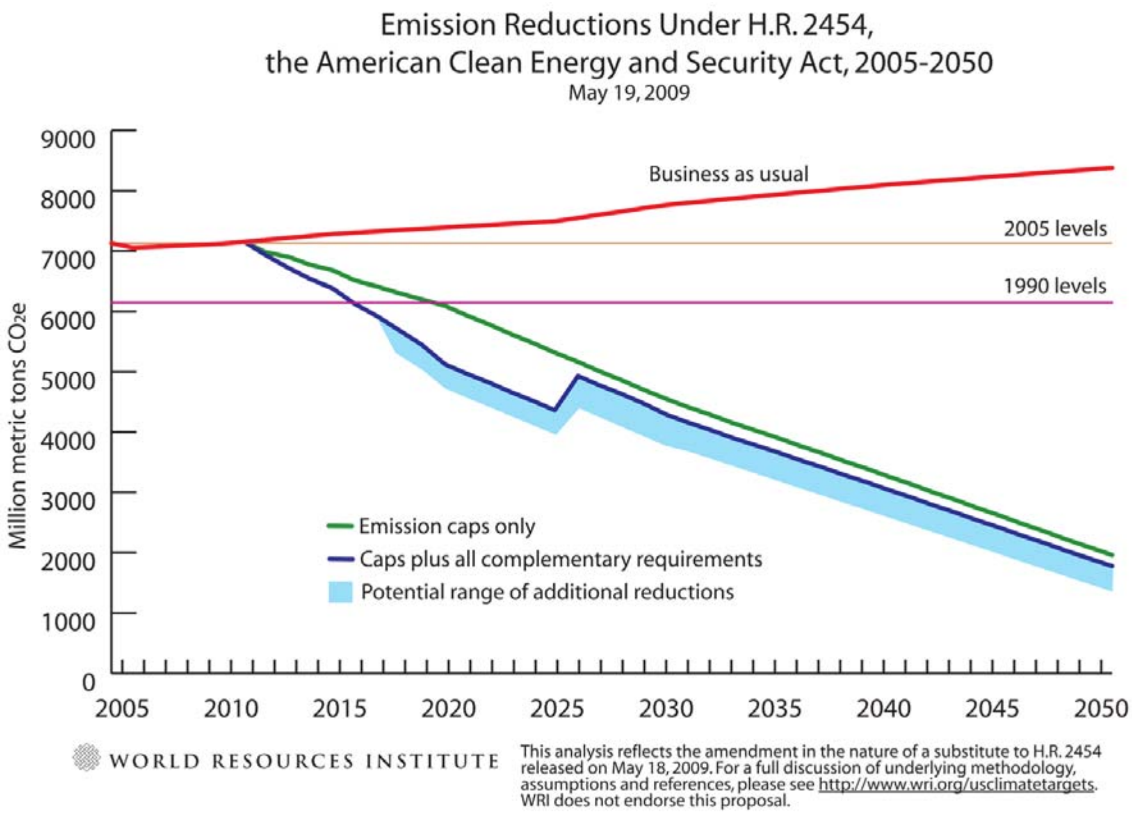


**Figure Synapse-3 -** **Emissions reductions that would be required under the Waxman-Market climate change legislation introduced in the current 111th U.S. Congress.**

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.[37] The EPA has now circulated its draft finding, for public comment, that greenhouse gas emissions endanger public health and welfare.[38] 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 plan would require emissions reductions that approximate the steepest reductions shown in Figure 1. 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 80 percent reduction below current levels.[39] 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.

Consumers Energy has made numerous claims about its projected emissions reductions from the BEI, including reductions in $CO_2$ emissions.[40] However, there are significant limitations and weaknesses in the evidence that the Company has offered to support these claims.

a. The Company has not provided any of the source documents and analyses for its projected future emissions. The workpapers for Figures 9 and 10 and Table 4 in the EGAA that Consumers Energy has provided essentially only repeated the same numbers that are shown in these Figures and Table and offered no information as to how they were derived. Consequently, it is not possible to verify that the Company has properly modeled its future emissions and that the claimed emissions reductions are reasonable.

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37 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."

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

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

40 At pages 22 to 24 of the EGAA, including Figures 9 and 10 and Table 4.

b. The Company appears to have modeled only two scenarios: The "Existing Fleet and No New Plant" and the "New Plant with Assumed Retirements." However, as noted above, the Company has not committed to retiring any existing coal capacity. Therefore, it should at least have modeled scenarios with the new plant with little or no retirements of existing coal plants. This is a more likely future given Consumers Energy's failure to commit to actually retiring any coal plants.

c. The Company appears to have failed to model scenarios that assume additional energy efficiency savings and renewable resources beyond the levels included in Balanced Energy Initiative. This is a significant failure given that the workpapers for Figure 10 in the EGAA show substantial reductions in Consumers Energy's projected $CO_2$ emissions in 2015 and 2016 before the start of commercial operations of the proposed Karn-Weadock coal plant. These reductions presumably are the result of the energy efficiency savings and the addition of new renewable resources plus the retirement of some existing coal plants.

d. The information on emissions provided by Consumers Energy in the EGAA only goes through the year 2018. Thus, it is impossible to determine what the Company's $CO_2$ emissions would be in subsequent years. As a result, it is not possible to determine whether the Company would achieve a long-term $CO_2$ emission reduction trajectory under the Balanced Energy Initiative that would be consistent with the national caps being considered in Congress and the administration.

e. The emissions information presented in Figures 9 and 10 and Table 4 are described as being for the Company's coal system and it is unclear whether they include the emissions from the Company's natural gas-fired units or from its market purchases.

**9. 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.**

We agree with Consumers Energy 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.

Figure Synapse-4, 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 in order to be consistent with the reduced nationwide emissions caps.

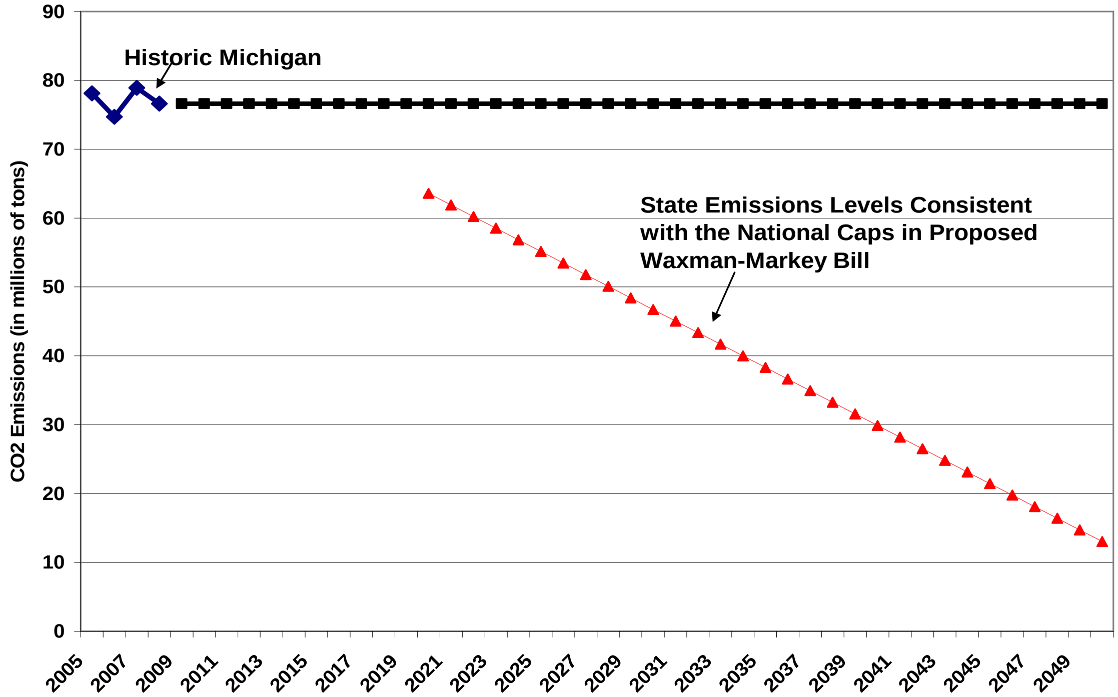


**Figure Synapse-4.** **The State of Michigan's Historic and Future $CO_2$ Emissions compared to the Emission Levels that Would Be Consistent with the National $CO_2$ Caps in the proposed Waxman-Markey Legislation.**

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.

**10. If it operates at an average annual 85 percent capacity factor, the proposed 830 MW Karn-Weadock plant will emit 5.8 million tons of $CO_2$ each year for an estimated 60 year operating life. There currently is no commercially viable technology for capturing $CO_2$ emissions from pulverized coal plants and significant uncertainty as to whether and when that technology will become viable. The claim that the plant will be "carbon capture ready" has no real substantive meaning but, instead, essentially suggests only that space has been set aside to accommodate currently unknown equipment for capturing $CO_2$ that would otherwise be emitted into the atmosphere.**

If it operates at an average annual capacity factor of 85 percent, the proposed Karn-Weadock coal plant would emit approximately 5.8 million tons of $CO_2$ each year of its likely 60 year operating life. That would mean that the unit would emit an additional 348 million tons, in total, of $CO_2$ into the atmosphere if it is operated for 60 years unless some technological fix, or silver bullet, is developed to capture $CO_2$ emissions from pulverized coal plants.

Consumers Energy says that the proposed coal plant "will be carbon capture ready and designed to accommodate the installation of carbon capture and sequestration ("CCS") when CCS becomes technically and economically feasible."[41] However, the claim that a proposed plant will be "carbon capture ready" really only means that the applicant is simply setting aside space for possibly adding, at some uncertain point in the future, currently unknown equipment for capturing $CO_2$ that would otherwise be emitted into the atmosphere and that the captured $CO_2$ would be piped to some presently unknown location where it would be sequestered geologically.

Consumers has not committed to taking any steps to actually capture and sequester, or otherwise limit, CO2 emissions from the Karn-Weadock plant, and nor has the company identified how it would do so. In fact, as Consumers itself acknowledges, there currently is no commercially demonstrated, economically viable method for the post-combustion removal of $CO_2$ from pulverized coal plants at full scale.[42] As Consumers Energy reports in the EGAA, some technologies are starting to be tested with plans for scale up but it might be years, if not decades, before there will be commercially viable post-combustion technology for the capture and sequestration of greenhouse gas emissions from pulverized coal-fired power plants like the proposed Karn-Weadock coal unit. [43] The Edison Electric Institute, for example, has said that it does not expect carbon capture and storage technologies to be commercially available until 2020 or 2025. And even that timeline might be overly optimistic.

A number of independent sources such as Duke Energy, the electric industry's Edison Electric Institute, the Massachusetts Institute of Technology and the U.S. Department of Energy's National Energy Technology Laboratory have estimated that adding carbon capture technology would increase the cost of generating power at a pulverized coal-fired plant by 60 percent to 80 percent. If shown to be technically and legally feasible, the costs of transporting and permanently sequestering the $CO_2$ in the ground would be in addition to these increases. However, given the substantial uncertain surrounding CCS technology and timing, any cost estimates, such as those presented by Consumers Energy, must be viewed as highly, if not completely, speculative.

The bottom line is that it is not prudent to approve a new coal-fired power plant with only a hope that the plant will someday capture and ultimately sequester 90 percent or more of its $CO_2$ emissions. Because if carbon capture and sequestration technology is not added to the proposed Karn-Weadock plant, Consumers Energy's customers instead would have to pay hundreds of millions of dollars each year to buy allowances to cover the plants' $CO_2$ emissions.

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41 EGAA, at pages and 5.

42 Footnote No. 39 on page 29 of the EGAA.

## 11. Ratepayers will face significant financial risk associated with the decision to lock in high levels of carbon emissions for the coming decades at a time when those emissions will be costly.

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.[44]

> 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.[45]

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:

> 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

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

[45] Ibid.

> 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.[46]

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.[47]

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.3 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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46 *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.

47 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. These forecasts are presented in Figure Synapse-5:

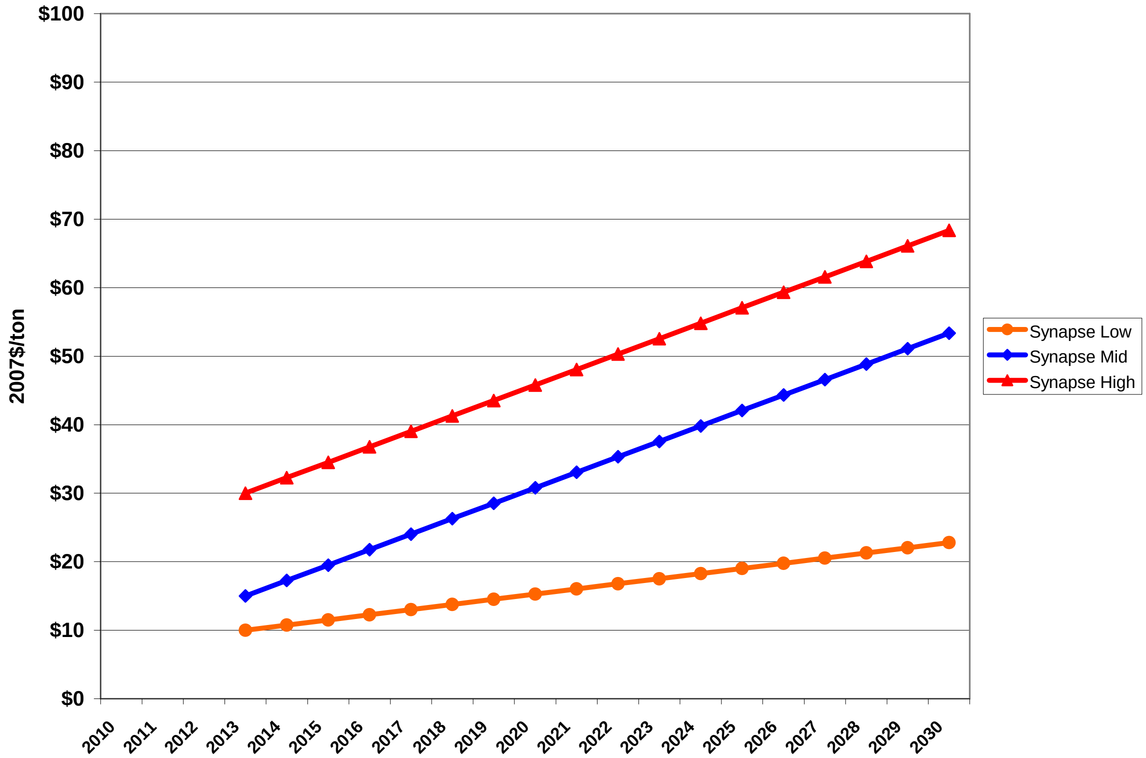


**Figure Synapse-5.** **Synapse 2008 $CO_2$ allowance price forecasts.**

The 2008 Synapse $CO_2$ Price Forecasts shown in Figure Synapse-5 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 this past summer to ensure that they reflect an appropriate level of financial risk associated with greenhouse gas emissions.[48] Most importantly, the political support for serious climate change legislation has expanded significantly in federal and state governments, as well as in the public at

48 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

large, as the scientific evidence of climate change has become more certain. Concurrently, the new 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 (as discussed below).

Consumers Energy does allow in its levelized cost analyses in the EGAA that a $CO_2$ tax or cap-and-trade program will be implemented in the U.S. in the near future, assuming a $CO_2$ cost of $22/ton beginning in 2012 and rising to $53/ton by 2025.[49] This $CO_2$ cost trajectory starts somewhat higher than the Synapse Mid-Forecast but over time decreases to a trajectory between the Synapse Low- and Mid-Forecasts. Although this single set of $CO_2$ prices is reasonable, the costs of any federal program to regulate greenhouse gas emissions will be affected by important details that are still uncertain, such as the timing, goals, and design of the program. Therefore, it is critical to consider a reasonably broad range of $CO_2$ emissions allowance prices in resource planning in order to achieve decisions that are robust in an uncertain future just as resource planners normally consider a range of fuel prices. Unfortunately, Consumers Energy has not done so.

Figure Synapse-6, below, compares the levelized $CO_2$ cost used by Consumers Energy 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.

[49] EGAA, at Footnote No. 35 on page 27.

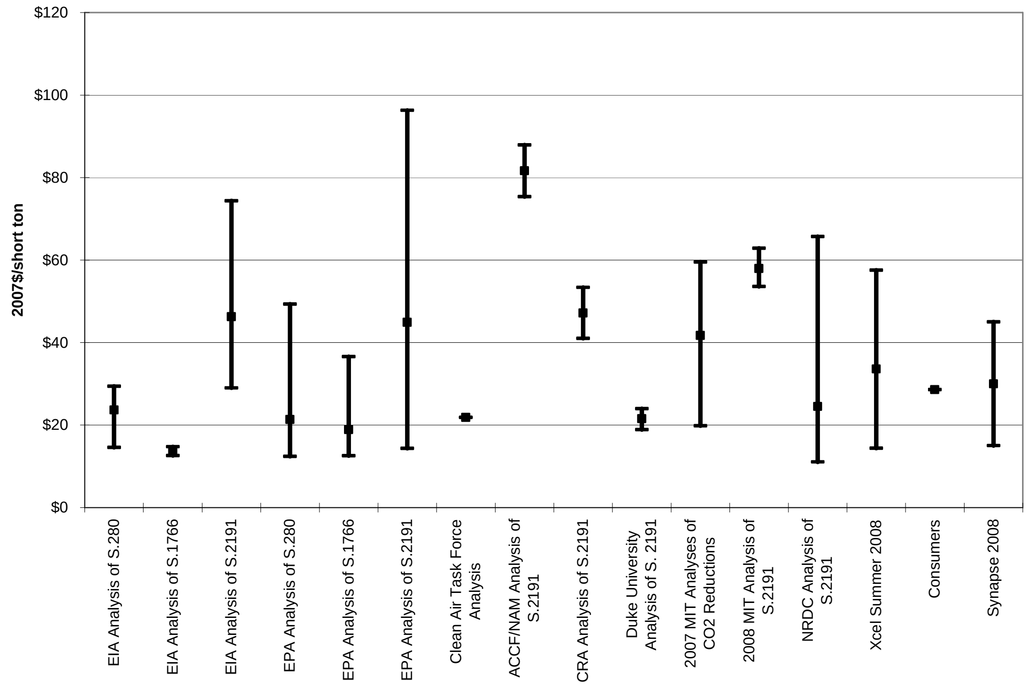


**Figure Synapse-6.** **$CO_2$ prices used by Synapse and Consumers Energy vs. results of modeling analyses of major bills in the U.S. Congress – levelized $CO_2$ prices (2013-2030, in 2007 dollars).**

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

Consumers Energy also presented levelized costs for the coal and natural resource options that assumed it would not have to pay for emissions allowances, that is, that the price of allowances was $0/ton. The failure to include any price for $CO_2$ heavily biased the results of these scenarios in favor of the proposed Karn-Weadock Plant, the coal alternative. The assumption that Consumers Energy would not have to pay any $CO_2$ prices at any time in the expected 60 year operating lives of the new coal plant that would come on-line in 2017 relies on one or both of two flawed assumptions: either that there will be no federal regulation of greenhouse gas at any point in the expected 40 to 60 year operating lives of new coal plants like the new Karn-Weadock unit or that Consumers Energy will receive free allowances for all of the $CO_2$ emissions from the new plants. Both of these assumptions are unrealistic in the face of the recently announced Administration cap-and-trade plan and legislative trends in the U.S. Congress. For this reason, any cost comparison that does not include $CO_2$ costs has no probative value and should not be given any weight.

As was discussed above, post-combustion carbon capture and sequestration technology is currently not economically viable, and when it becomes viable, it will impose a significant cost on utilities, and therefore, to consumers. But if carbon capture and sequestration technology is not added to the proposed Karn-

Weadock plant, Consumers Energy's customers instead would have to pay anywhere from tens to hundreds of millions of dollars each year to buy allowances to cover the plants' $CO_2$ emissions – allowances that would be auctioned as part of the cap-and-trade program. The annual costs for purchasing the allowances for the approximate 5.8 million tons of $CO_2$ that the proposed coal plant would emit each year are shown in Figure Synapse-7, below. The annual costs in this Figure reflect the Synapse High, Mid and Low $CO_2$ price trajectories shown in Figure Synapse-5, above, as well as the price trajectory assumed by Consumers Energy in the EGAA. Although Figure Synapse-7 only goes through 2030, it is reasonable to anticipate that the Company's customers would have to pay these increasing annual costs right through the end of the operating lives of the proposed Karn-Weadock plant, or until the capability for carbon capture and sequestration is added to the facility.

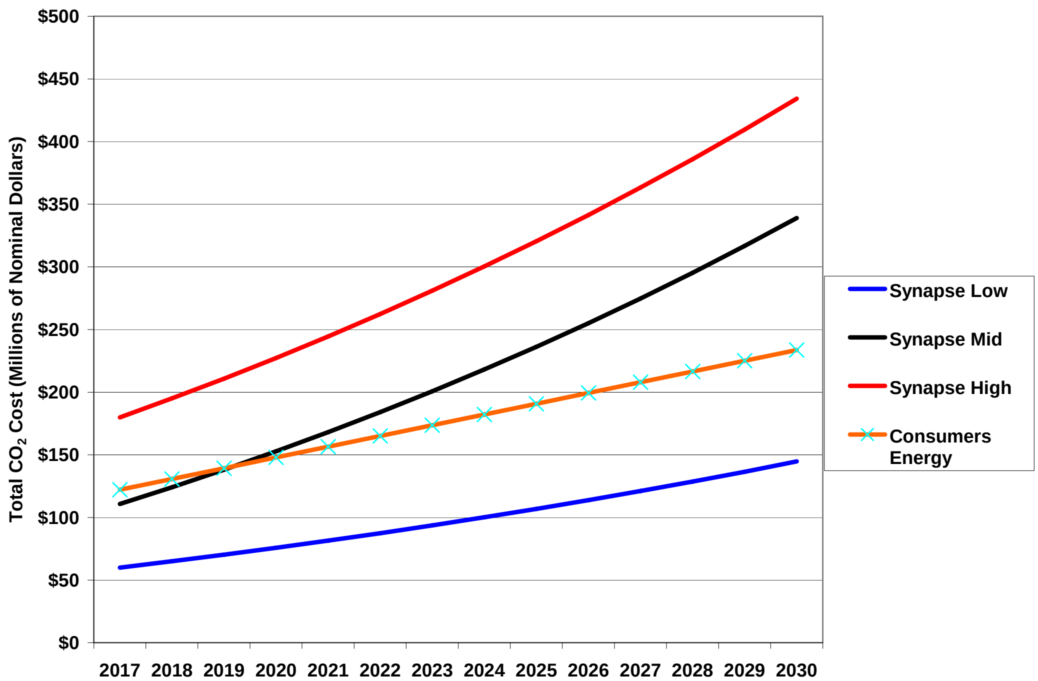


**Figure Synapse-7.** **Proposed Karn-Weadock annual $CO_2$ costs –operating at an average 85 percent capacity factor (millions of nominal dollars).**

Thus, if it builds the proposed Karn-Weadock coal plant, Consumers Energy's customers may have to pay between $76 million and $227 million for the Company's share of the $CO_2$ emitted by that plant in 2020, and these costs could rise to between $145 million and $434 million in 2030. Of course, these costs would be higher if the Company doesn't share ownership of the proposed 830 MW and its customers were responsible for paying for all of the $CO_2$ it emits.

## 12. The estimated cost of the proposed Karn-Weadock coal plant has increased by 32 percent since the Company filed its original Balanced Energy Initiative in 2007. The plant's cost may increase further before it is completed.

The estimated construction cost of the proposed Karn-Weadock coal plant has increased from $2,765 per kW in 2007 to $3,589 per kW in January 2009, a 32 percent increase.[50] Both of these estimates excluded AFUDC or other financing costs. The new cost estimate roughly translates into a total plant cost, without financing costs, of $3 billion. With financing costs, the total cost of the plant can be expected to exceed $3.5 billion. Consumers Energy's 519 MW share of the plant would be $1.86 billion without financing costs, and in excess of $2.1 billion with financing costs.

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.

There are, of course, no guarantees that the construction costs of new coal plants such as Karn-Weadock 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:

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[50] 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.

> 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.[51] [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 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.[52]

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, recently has 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.[53]

In addition, even though there is now a worldwide economic slowdown, there still is 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

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51 Ibid, at page 16, lines 16-20.

52 *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.

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

infrastructure repairs and improvements – the Engineering News-Record has reported that these stimulus efforts will pump trillions of dollars into the world economy.[54] 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.

**13. The EGAA does not consider the risks associated with different supply and demand side plans. In fact, other than considering levelized costs for resources with and without $CO_2$ costs, the EGAA did not consider uncertainty for any of the key input parameters.**

The levelized cost analyses in the EGAA do not represent economic analyses of the overall resource plan included as the Balanced Energy Initiative. Instead the levelized cost analyses merely compare the costs of individual resource options. A generation expansion (and perhaps production simulation modeling) is needed to consider all feasible supply and demand options and to optimize the mix and the timing of resource additions. The levelized cost analyses in the EGAA do not provide this information.

Moreover, risk and uncertainty are inherent in all enterprises. But the risks associated with any options or plans need to be balanced against the expected benefits from each such option or plan.

In particular, parties seeking to build new generating facilities and the associated transmission face of a host of major uncertainties, including, for example, the expected cost of the facility, future restrictions on emissions of carbon dioxide, and future fuel prices. The risks and uncertainties associated with each of these factors needs to be considered as part of the economic evaluation of whether to pursue the proposed facility or other alternatives.

One traditional way to assess risk is to conduct scenario analyses that look at reasonable ranges of values for the key input assumptions such as capacity capital costs, fuel prices, $CO_2$ costs, load and energy requirements, etc. Unfortunately, except for assuming that there will be regulation of greenhouse gas emissions starting in 2012, the levelized cost analyses presented in the EGAA do not include any assessment of the uncertainty or risks associated with any of the critical input assumptions such as higher capital costs or higher or lower fuel prices. Instead, the Company merely presented levelized costs in terms of $/MWh for a single set of construction costs, a single set of fuel prices, a single set of $CO_2$ prices, etc.

Similarly, the assessment of need presented in the EGAA also did not look at a range of projected future loads and energy requirements. Again, the Company only considered a single set of forecasts load and energy requirements and did not consider a range of possible future loads or a range of potential energy efficiency savings or possible renewable resource additions.

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[54] Ibid, at page 18.

## 14. The levelized cost analyses in the EGAA did not adequately consider portfolios of alternatives to the proposed Karn-Weadock coal plant that would include existing and/or new gas, more wind, and additional cost-effective energy efficiency.

Except for two portfolios that included wind and new gas-fired combustion turbine capacity, Consumers Energy did not consider any other portfolios of alternatives to the proposed Karn-Weadock coal plant. It did not consider any portfolios of alternatives to the proposed coal plant that include additional energy efficiency and/or demand response or load management efforts. This was unreasonable given the very low cost of $35/MWh, on average, that the EGAA presents for energy efficiency, a cost much lower than the cost of the new coal and gas supply-side options.[55]

The Company also did not consider any portfolios that included increased generation at existing combined cycle or combustion turbine units despite reporting that its existing gas-fired plants had very low capacity factors. A prudent resource planning assessment would have looked at a range of possible alternative portfolios that included varying mixes of energy efficiency, existing and new natural gas capacity, and renewable resources such as wind, biomass, landfill gas, combined heat and power and the other alternatives listed in Table 7 of the EGAA.

## 15. The use of unreasonably high natural gas prices biases the levelized cost analyses in the EGAA in favor of coal.

The levelized cost analyses for the natural gas-fired alternatives reflected very high natural gas prices, starting at $7.62/MMBtu in 2009 and increasing to $25.70 in 2030 and growing substantially higher in subsequent years.[56] These projected natural gas prices are significantly higher than other current forecasts.

For example, Figure Synapse-8 below compares the natural gas prices used by Consumers Energy in the levelized cost analyses in the EGAA with the AEO's March 2009 forecast for the East Central Region, that includes Michigan, and with the AEO's April 2009 revision that reduced forecast natural gas prices even further. As can be seen, the Consumers Energy forecast gas prices are much higher than the projected AEO prices in every year.

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[55] EGAA, Table 7, at page 37.

[56] See the 44th and 45 pages of Consumers Energy's June 15, 2009 filing of workpapers.

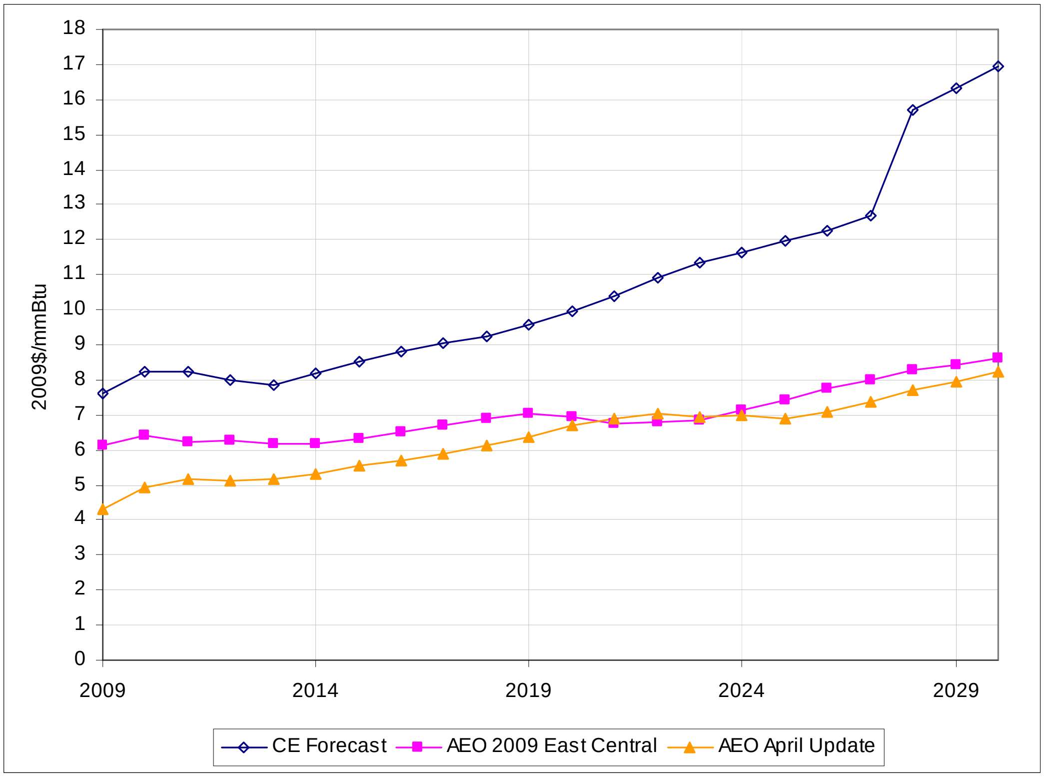


**Figure Synapse-8.** **Consumers Energy vs. Recent AEO Natural Gas Price Forecasts**

The dramatic recent reductions in the current and projected prices of natural gas have been attributed to what some, including Entergy Louisiana, have called a structural change in the natural gas market. For example as a result of this structural change, and other uncertainties, Entergy Louisiana has decided to suspend construction of a coal plant and instead pursue the construction of a new natural gas-fired combined cycle unit: "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."[57]

Entergy Louisiana also identified the changed circumstances that had led it to the conclusion that the construction activities for its proposed Little Gypsy 3 coal plant 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

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

> 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.[58]

Entergy also 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:

> 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

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[58] Id, at pages 6-8.

> because of the newly discovered ability to produce gas through non-traditional recovery methods…[59]

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.[60] The existence of higher reserves and the new recovery techniques discussed by Entergy support the conclusion future natural gas prices should not be nearly as high as was forecast last year or even earlier this year.

Our review of Consumers Energy's workpapers suggests that the Company did not increase natural gas prices in the scenario with a $CO_2$ cost. We believe that this was appropriate. 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.

Figure Synapse-9, 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-9 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-

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59 Id, at pages 17, 18 and 22.

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

Lieberman bill), Senate Bill S.1766 (the Bingaman-Specter bill) and Senate Bill S.2191 (the Lieberman-Warner bill).

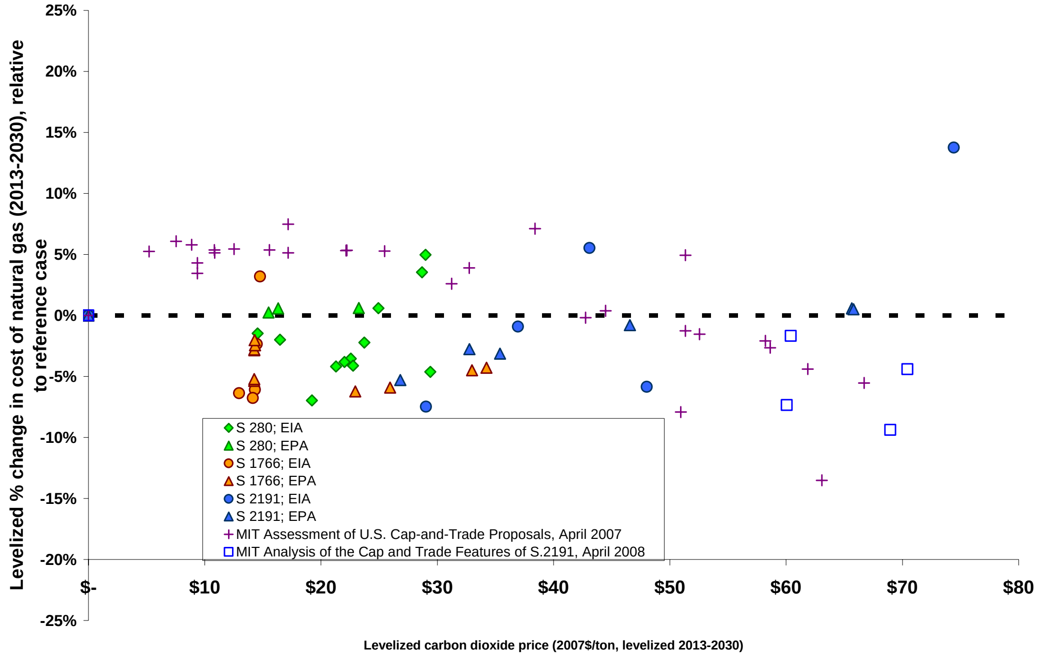


**Figure Synapse-9.** **The relationship between $CO_2$ emissions allowance prices and natural gas prices.**

As shown clearly in Figure Synapse-9, there is no evidence to support an assumption that there would be a very significant increase in the levelized price of natural gas at a relatively low levelized $CO_2$ price. Such an assumption is not supported by the results of the independent modeling analyses of carbon dioxide regulation. Instead, as can be seen from Figure Synapse-9, 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 Consumers Energy has assumed – and that single scenario featured a levelized $CO_2$ price of approximately $75/ton, a far higher price than Consumers Energy has assumed in the EGAA. In fact, in some scenarios, the models forecast that the adoption of greenhouse gas regulation might lead to lower natural gas prices as natural gas usage and demand declined due to its greenhouse gas emissions.

It is generally accepted that a strategy for reducing our national greenhouse gas emissions will require adding large amounts of new wind capacity and energy. A recent study by the U.S. Department of Energy's National Renewable Energy Laboratory examined the costs and benefits of achieving 20 percent wind energy penetration by 2030.[61] One of the benefits that the study found was that wind

[61] *20 Percent Wind Energy by 2030*, available at http://www.20percentwind.org/20p.aspx?page=Report.

generation could displace up to 50 percent of the electricity that would be generated from natural gas – this, in turn, translates into a reduction in national demand for natural gas of 11 percent.[62] Thus, carbon legislation, when coupled with increasing amounts of wind capacity and energy, may not lead to any increases in the demand for and the costs of natural gas over the long term.

**16. The use of high coal plant and extremely low natural gas plant capacity factors biases the levelized cost analyses in the EGAA in favor of coal.**

The levelized cost analyses reflected very high coal plant capacity factors, especially in the initial "break-in" years in which they average approximately 91 percent.[63] While it is reasonable to assume that a new coal plant will be operated as a baseload unit, it is extremely optimistic to assume that a new unit will initially operate at better than a 90 percent capacity factor. The projected capacity factors of other proposed coal plants are not quite that high – usually between 85 percent and 90 percent.

At the same time that the levelized cost analyses presented in the EGAA reflect very high coal plant capacity factors, they reflected extremely low capacity factors for new natural gas-fired combined cycle and combustion turbine facilities – 15 percent for a new combined cycle unit and 3 percent for a new combustion turbine.[64] These assumed capacity factors make no sense. The fact that the Company's existing combined cycle and combustion turbines have recently had very low capacity factors is not persuasive. The point of the economic comparisons is to compare options that provide the same amounts of capacity and energy. Assuming very low capacity factors for the natural gas alternatives means that the capital costs for those options are spread over relatively small numbers of MWh of output. This increases the costs of these alternatives.

The low 15 percent capacity factors assumed in the levelized cost analyses for a new combined cycle plant are even more unreasonable given Consumers Energy's admission that these facilities have high availabilities, generally in the low 90 percent range. Thus, if a new combined cycle were built in place of the proposed Karn-Weadock coal plant, it is reasonable to expect that it could and would be operated at more than a 15 percent capacity factor. If the Company believes that a new 600 MW combined cycle plant would not, on its own, produce the same amount of energy as a new baseload coal plant, it should have examined portfolios with natural gas, wind and energy efficiency that could provide the same levels of capacity and energy as the proposed baseload coal unit.

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62 Id, at pages 16 and 154.

63 See the assumed capacity factors for a new Advanced Supercritical Pulverized Coal Plant, presented at the 26th page of Consumers Energy's June 15, 2009 filing.

64 EGAA Footnotes Nos. 48 and 49, at page 36.

In fact, if the Company believes that existing combined cycle units, such as the Zeeland plant, will continue to operate at such very low capacity factors, then increasing generation at those facilities should offer a reasonably priced option for producing additional energy. As Consumers Energy appears to acknowledge, with availabilities in the 90 percent range, there is no reason why a combined cycle plant should not and could not operate at annual capacity factors in the range of 60 percent to 70 percent or higher.

**17. The levelized cost analyses in the EGAA are biased in favor of coal by the unrealistic assumption that all of the alternatives considered were in service as of the beginning of 2009.**

Consumers Energy began each of its levelized cost analyses in 2009 which meant that all of the alternatives considered actually began operations at the start of 2009 instead of in 2017 when the proposed coal plant is scheduled to be completed. This was completely unrealistic and biased the analyses in favor of coal.

As shown in the excerpt from one of the workpapers for Table 5 in the EGAA, beginning the analyses in 2009 means that Consumers Energy essentially ignored the first three years of $CO_2$ costs because $CO_2$ regulation was assumed to not start until 2012. If the analyses had properly started in 2017, the costs of the coal and gas alternatives would have reflected $CO_2$ costs in the first year of operations, not in the fourth year and also would have overall higher costs during the levelization period.

Instead, assuming that all of the alternatives began operations in 2009 favored the highest carbon dioxide emitting alternative, the coal plants. This can be seen from the $0 value for $CO_2$ for 2009, 2010, and 2011 on line 46 in Table Synapse-5, below, which is an excerpt from the workpapers for Table 5 in the EGAA (for the Advanced Supercritical Pulverized Coal option).

**BEI Electric Generation Alternatives Analysis**
**Table 5 - Coal Technology Cost Summary**
**Levelized Cost of Advanced Supercritical Pulverized Coal Plant**

| | | | | | | |
|---|---|---|---|---|---|---|
| 1 | COD (Jan1) | 2009 | | | | |
| 2 | Size MW | 830 | | | | |
| 3 | Plant Life Years | 40 | | | | |
| 4 | Last Year of Service | 2048 | | | | |
| 5 | Capital Cost + AFUDC (EOY 2008) $/kW | 3276 | | | | |
| 6 | Capital Cost (@ COD) $/kW | 3276 | | | | |
| 7 | Network Upgrade Cost (EOY 2009) $/kW | 166 | | | | |
| 8 | Network Upgrade Cost (@ COD) $/kW | 166 | | | | |
| 9 | Capital Fixed Charge Rate | 12.3807% | | | | |
| 10 | Network Upgrade Fixed Charge Rate | 20.0000% | | | | |
| 11 | Capital Cost Escalation Rate | 4% | | | | |
| 12 | O&M Escalation Rate | 2% | | | | |
| 13 | Long-term NOx Escalation Rate (2031+) | 0.00% | | | | |
| 14 | Long-term SO2 Escalation Rate (2031+) | 2.50% | | | | |
| 15 | Long-term CO2 Escalation Rate (2031+) | 7.50% | | | | |
| 16 | Long-term Fuel Escalation Rate (2031+) | 2.60% | | | | |
| 17 | Discount Rate | 8.98% | | | | |
| 18 | | | | | | |
| 19 | | | | | | |
| 20 | | | 2009 | 2010 | 2011 | 2012 |
| 21 | NOx | $/Ton | 2,626.56 | 2,584.54 | 2,428.39 | 2,489.10 |
| 22 | SO2 | $/Ton | 174.25 | 458.61 | 742.96 | 1,027.32 |
| 23 | CO2 | $/Ton | 0.00 | 0.00 | 0.00 | 22.30 |
| 24 | Fuel | $/MMBtu | 1.98 | 2.51 | 2.59 | 2.66 |
| 25 | Heat Rate | Btu/kWh | 9,134 | 9,134 | 9,134 | 9,134 |
| 26 | FOM | $/kW-yr | 35.88 | 36.60 | 37.33 | 38.08 |
| 27 | VOM | $/MWh | 2.47 | 2.52 | 2.57 | 2.62 |
| 28 | NOx | lb/MMBtu | 0.05 | 0.05 | 0.05 | 0.05 |
| 29 | SO2 | lb/MMBtu | 0.06 | 0.06 | 0.06 | 0.06 |
| 30 | CO2 | lb/MMBtu | 206.30 | 206.30 | 206.30 | 206.30 |
| 31 | NOx | lb/MWh | 0.46 | 0.46 | 0.46 | 0.46 |
| 32 | SO2 | lb/MWh | 0.55 | 0.55 | 0.55 | 0.55 |
| 33 | CO2 | T/MWh | 0.94 | 0.94 | 0.94 | 0.94 |
| 34 | | | | | | |
| 35 | Size | MW | 830 | 830 | 830 | 830 |
| 36 | Capacity Factor | % | 91.07% | 90.69% | 91.10% | 91.10% |
| 37 | Generation | GWh | 6,622 | 6,594 | 6,624 | 6,624 |
| 38 | | | | | | |
| 39 | Capital Cost | $000 | 336,641 | 336,641 | 336,641 | 336,641 |
| 40 | Network Upgrade Cost | $000 | 27,556 | 27,556 | 27,556 | 27,556 |
| 41 | Fuel Cost | $000 | 119,918 | 150,922 | 156,688 | 161,148 |
| 42 | Fixed O&M | $000 | 29,784 | 30,380 | 30,987 | 31,607 |
| 43 | Variable O&M | $000 | 16,358 | 16,616 | 17,024 | 17,364 |
| 44 | NOx | $000 | 3,972 | 3,892 | 3,673 | 3,765 |
| 45 | SO2 | $000 | 316 | 829 | 1,348 | 1,865 |
| 46 | CO2 | $000 | 0 | 0 | 0 | 139,143 |
| 47 | | | | | | |
| 48 | Total Cost (Mix of Annual+Levelized) | $000 | 534,545 | 566,835 | 573,917 | 719,089 |
| 49 | 40-Year Levelized Cost | $000 | 839,790 | 839,790 | 839,790 | 839,790 |
| 50 | Total Cost (Mix of Annual+Levelized) | $/MWh | 81 | 86 | 87 | 109 |
| 51 | | | | | | |
| 52 | | | | | | |

**Table Synapse-5. Excerpt from Consumers Energy's Workpapers for Levelized Cost of Advanced Supercritical Pulverized Coal Unit.**

Simply moving the coal plant's initial operating date from 2009 to 2017 increases its levelized costs, including Consumers Energy's $CO_2$ costs, from $133 per MWh to $169 per MWh.

Synapse has recomputed the levelized costs for the advanced supercritical pulverized coal and the natural gas combined cycle options assuming (1) that the new plants would begin operations in 2017, not 2009, (2) a conservative 70 percent capacity factor for a new combined cycle plant, and (3) the more recent AEO fuel prices discussed earlier. None of the Company's other assumptions were changed. Under these circumstances, the levelized price for a new natural gas combined cycle plant was $143/MWh, less than the $169/MWh levelized cost of an advanced supercritical pulverized coal unit.

**18. The use of very high wind costs biases the levelized cost analyses in the EGAA in favor of coal.**

The wind prices used by Consumers Energy in the EGAA, $198/MWh for on-shore wind without CT backup and $212-385/MWh for off-shore wind without CT backup, were among the highest, if not the highest levelized prices for wind that we have seen in resource planning. These estimated costs are much higher than other state and national wind cost projections and are so high as to not be credible. For example, in its recently filed EGAA, Wolverine Power Cooperative presents a levelized cost of $88/MWh for wind – which were only 44 percent as high as the prices used by Consumers Energy in its EGAA.[65] Moreover, as the Michigan PSC noted in its May 26, 2009 Order in Case No. U-15805, the Commission recently approved a contract for Detroit Edison to purchase wind energy at a price of $115 per MWh for 20 years.[66]

Consumers Energy's projected wind prices also are significantly higher than national estimates. For example, the financial firm Lazard recently estimated a range of levelized wind costs of $57/MWh to $113/MWh.[67] The Commission also has noted that the parties in Case No. U-15805 had presented evidence that providers in other states have paid less than $100 per MWh for wind energy.[68]

It appears that the very high levelized prices that Consumers Energy projects for wind are based on a number of questionable assumptions that each biases the analyses against wind:

(1) Very high, and escalating wind capital costs

(2) No continuation of the federal production tax credit beyond its current expiration date of 2012

(3) A very short service life for new wind facilities such that they would have to be replaced, in total, after operating lives of only 20 years.

65 Wolverine EGAA, dated June 8, 2009, Figure 6.6 at page 99 of 114.

66 At page 15.

67 *Levelized Cost of Energy Analyses – Version 3.0,* Lazard, June 2009, at page 2.

68 *Opinion and Order in Case No. 15805*, May 26, 2009, at page 13.

(4) That there will not be any improvements in wind technology that would allow increased operating performance. As a result, future wind facilities would be limited to not-very-aggressive 28.5 percent average annual capacity factors.

(5) A low 12.5 percent capacity credit for wind.

Consumer Energy's levelized cost analyses assumed a capital cost of $2,427/kW for a wind facility which, in the analyses, began operations at the start of 2009. The Company then assumed that the wind capital costs would increase over time so that the cost of installing replacement wind turbines in 2029 would be $4,384/kW.[69]

In fact, there is evidence that wind turbine costs peaked in 2008 and both short-term and long-term forecasts are for declines in wind capital costs in real terms over the coming decades. For example, Wisconsin Electric Power Company filed an application in October 2008 for Wisconsin Public Service Commission approval of a proposed wind facility. In May 2009, the Company submitted an update to its application to reflect "wind turbine prices:"

> Market conditions for the procurement of wind turbine equipment have changed considerably since Wisconsin Electric initially submitted is application.[70]

The Wisconsin utility subsequently filed testimony that documented a substantial decrease in wind capital costs:

> Shortly after we filed our application for a CPCN on October 24, 2008, it became apparent that the wind turbine market was softening considerably and that prices were decreasing accordingly. Since that time, Wisconsin Electric has been working with the vendors to solidify the best opportunity for the project and its customers and has received updated proposals for the Gamesa G90, GE 1.5xle, Vestas V90-1.8 and Siemens SWT-2.3-93. All of the vendors lowered their prices and improved other characteristics of their offerings.[71]

And:

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69 Consumers Energy's June 15, 2009 filing of the workpapers for the EGAA, at the 48th page.

70 PSCW Docket No. 6630-CE-302, *Motion for Leave to File Supplemental Direct Testimony and for Extension of Deadlines*, dated May 2009, at page 2.

71 PSCW Docket No. 6630-CE-302, Supplemental Direct Testimony of Richard E. O'Conor, May 2009, at page 217.

> The capital cost estimate for the largest wind turbine under consideration, exclusive of AFUDC, has been reduced from $525.6 million to $413.5 million.[72]

Even before the declines in wind costs documented by Wisconsin Electric, it was generally expected that wind capital costs would decline over time, in real terms, due to the addition of substantial new manufacturing capacity and the elimination of supply bottlenecks. For example, an interim report for the first quarter of 2009 for Vestas, a supplier of wind turbine components noted:

> Component prices peaked in 2008 and are not expected to rise in 2009 because of the weaker economic growth. Longer term, lower raw materials prices could lead to lower prices of wind turbines. Large-scale investments throughout the supply chain have eliminated any immediate risk of bottlenecks and, by extension, Vestas' need for buffer stocks, which will henceforth be reduced.
>
> * * * *
>
> The number of providers and sub-suppliers is growing, leading to intensified competition throughout the value chain.
>
> * * * *
>
> Vestas is investing heavily in new capacity in the USA and China, as the long-term goal is to supply "North America from the USA."[73]

In fact, a 2007 report for the American Wind Energy Association by the respected coal plant builder, Black & Veatch, had already projected that on-shore wind capital costs would decline in real terms by 10 percent from 2010 through 2030 and that wind turbine capacity factors would increase by 12 to 23 percent from 2005 through 2030.[74] Black & Veatch projected similar declines in capital costs and improvements in capacity factors for off-shore wind plants, as well.

Consumers Energy also assumed that the federal Production Tax Credit ("PTC") for wind would not be extended beyond the end of 2012.[75] Although there is uncertainty about the long-range continuation of the wind PTC, we believe that it is reasonable to assume that the PTC will be renewed after 2012 given (1) its history, (2) increasing concerning over U.S. dependence on foreign sources of

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72 PSCW Docket No. 6630-CE-302, Supplemental Direct Testimony of Stephen R. Jones, May 2009, at page 215.

73 Vestas, Interim Report for 1st Quarter 2009., at pages 3 and 7.

74 *20 Percent Wind Energy Penetration in the U.S.*, at page 1-5. Available at http://www.20percentwind.org/Black_Veatch_20_Percent_Report.pdf.

75 EGAA, Table 7, page 36.

energy, (3) mounting concern over global warming and climate change leading to increased interest in providing subsidies to non-carbon emitting technologies and (4) interest in stimulating green jobs in the USA. In any event, if Consumers Energy truly is concerned about the uncertainty surrounding the renewal of the PTC after 2012 it should have run several sensitivity scenarios for the EGAA, both with and without the PTC. However, it chose to present the scenario, without the PTC, that favors its proposed coal plant and biases the analysis against additional wind.

The assumption of a short twenty year operating life for a new wind turbine also biased the analyses against wind and in favor of coal. First, the shorter operating life mean a higher Capital Recovery Factor because of a higher depreciation rate (5.0 percent for wind versus 2.675 percent for coal). This meant unreasonably high annual capital costs for the wind alternatives. At the same time, the shorter operating life assumed for the wind facility meant that a substantially more expensive replacement would have to be installed in 2029 – this too increased the annual capital costs of the wind option after 2029 and, hence, the overall levelized cost of the wind option.

In addition, the Company assumed that the new wind facilities would be limited to 28.5 percent capacity factors. This is an unreasonable assumption. There have been technological improvements that will permit better performance from new wind turbines and discussions in the Midwest ISO have considered the possible use of 32 percent to 40 percent capacity factors for wind facilities.

**19. 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.[76]

[76] Order No. PSC-07-0557-FOF-EI, Docket No. 070098-EI, July 2, 2007.

In April of 2008, the Virginia State Corporation Commission rejected a proposed coal plant citing uncertainties of costs, technology, and unknown federal mandates.[77] 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."[78]

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."[79] 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."[80]

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.[81] 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."[82]

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.
  >
  > 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

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

[78] Id, at page 5.

[79] Id, at page 10.

[80] Id, at page 10.

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

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

> 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.[83]

- 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."[84]

- 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.[85]
>
> There also is increasing uncertainty in the regulatory environment, and Congress continues to debate the

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

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

[85] 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.

> environmental and economic impact of reducing greenhouse gas emissions, making the cost of reducing carbon dioxide from power plants unknown.[86]

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.[87]
- 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.[88]
- 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.[89]
- 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.

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[86] http://www.aeci.org/NR20080303.aspx.

[87] NV Energy Press Release, dated February 9, 2009.

[88] http://www.alliantenergy.com/Newsroom/RecentPressReleases/023120.

[89] "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.

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.[90] The 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."[91] 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

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

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

> 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 $CO_2$ 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.[92]

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

[92] Ibid, at pages 6-8.

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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

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[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.

# 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.