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November 30, 2014

Ms. Gina McCarthy
Administrator
U.S. Environmental Protection Agency
Attention: Docket ID No. EPA-HQ-OAR-2013-0602
1200 Pennsylvania Avenue, NW
Washington, DC 20460

Subject: Comments on EPA's Proposed Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, Docket ID No. EPA-HQ-OAR-2013-0602

Dear Administrator McCarthy:

The Wisconsin Department of Natural Resources (WDNR), in conjunction with the signatory Commissioners of the Public Service Commission of Wisconsin (PSCW), is submitting these comments regarding the United States Environmental Protection Agency's (EPA's) proposed "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units" ("Clean Power Plan") published in the Federal Register on June 18, 2014 (*79 FR 34830*). While this letter touches on some of the major issues associated with EPA's proposal, attached are detailed comments relating to the following specific aspects of the proposed rule:

- General comments on the proposal and EPA's approach
- Specific comments on the four "building blocks"
- Technical corrections to EPA's data for Wisconsin
- Actions taken by Wisconsin to reduce power sector CO_2 emissions
- Legal issues associated with EPA's proposed action
- Wisconsin-specific modeling results and cost estimates

We request that EPA thoroughly consider the comments and information provided in the attachments, make the necessary corrections and adjustments to any state data used to develop emission reduction goals, and modify the rule as needed to address the concerns we raise.

EPA provided additional information related to its proposal in a notice of data availability (NODA) published on October 30, 2014 (*79 FR 64543*). Wisconsin has provided comments on the specific issues and alternatives raised in the NODA in a separate submission to the docket. EPA also published a technical support document on translating rate-based CO_2 goals to mass-based equivalents on November 13, 2014 (*79 FR 67406*), which we considered in the comments provided in this submittal.

To give context to our comments, we want to first remind EPA that Wisconsin has made significant strides in reducing CO_2 emissions from the power sector over the past 15 years. In fact, Wisconsin was among the first states to implement many actions EPA is just now considering in its proposal. For example, in 1999 Wisconsin became the first state to enact a renewable portfolio standard (RPS) without having restructured its electric utility industry. In 2005, Wisconsin increased the RPS to 10%. Our utilities embraced the challenge, achieving our statewide target of 10% renewable generation in 2013 – two full years ahead of schedule.

Wisconsin also was an early adopter of energy efficiency programs, having implemented a utility-funded energy efficiency and renewables program (known as Focus on Energy) since 2001. This initiative recently received EPA's 2014 Energy Star "Partner of the Year - Sustained Excellence Award" for its years of leadership in protecting the environment through superior energy efficiency measures. This program, combined with the state's early actions to promote renewable energy, resulted in more than 10 million tons of avoided CO_2 emissions in 2013 – <u>equivalent to a 20% reduction from 2005 emissions</u>.

At the same time, Wisconsin also meaningfully reduced CO_2 emissions from our fossil-fuel plants. Wisconsin's utilities are regulated by the Public Service Commission of Wisconsin (PSCW), which means they have been and continue to be incentivized to improve and maintain efficient fleets. As a result, over the past two decades our utilities have closed many older coal-burning plants, improved the efficiency of those remaining, and invested in cleaner natural gas facilities. In addition, they have constructed several of the newest, most efficient coal-fired plants in the nation. We take pride in the fact that we have been able to sustain a reliable base of electrical generation while simultaneously reducing emissions and improving the quality of our air. In fact, EPA's own data shows that, of the highest CO_2-emitting power plants in the nation, Wisconsin does not have a single unit listed in the top 50, and only one in the top 100.[1]

It is unfortunate, then, to see that Wisconsin's early, aggressive, and measureable actions to reduce CO_2 emissions are largely ignored by EPA's proposed best system of emission reduction (BSER) approach. In fact, rather than recognizing and rewarding our leadership, EPA's proposal seriously penalizes Wisconsin relative to other states that have taken little to no action on renewables, energy efficiency, and traditional "inside the fence line" controls. This will have real and dramatic consequences on Wisconsin ratepayers, as well as the state economy. <u>Above all else, it is imperative that EPA address and remedy these inequities in any final rule</u>.

As mentioned above, attached are detailed comments regarding this proposal. In summary, our core issues with the proposed rule include the following:

- <u>Insufficient credit for CO_2 reductions already achieved</u>. As noted above, a fundamental weakness in EPA's proposal is that it fails to recognize the CO_2 reductions that Wisconsin (and other early acting states) has already achieved. This problem persists throughout the proposal, but in particular in EPA's proposed structure and implementation of the BSER building blocks, and use of the recent and unrepresentative single baseline year of 2012.

- <u>Inequity across states</u>. Relatedly, states that already reduced emissions significantly, such as Wisconsin, are being asked to reduce emissions *more* than states that have done less. In addition, states that emit the most CO_2 are asked to do the least. As a result, states end up with very different, and largely counterintuitive, emissions reduction goals. These inequities and the methods used to apply the building blocks to each state must be addressed in any final rule.

- <u>Inability of the building blocks to be implemented as proposed</u>. EPA defined BSER in this proposal using four building blocks. However, EPA generally fails to recognize that the four building blocks, if applied simultaneously, work against each other. For instance, Wisconsin's modeling consistently

[1] U.S. EPA, Inventory of Greenhouse Gas Emissions from Large Facilities, 2012.

shows that increasing in-state gas generation to comply with building block 2 drives coal-fired plants to become load-following and less efficient, thereby making building block 1 entirely unattainable. In setting BSER, EPA must adjust its building blocks to reflect what is actually achievable by an individual state in practice.

- EPA's approach to setting the baseline year. EPA's selection of 2012 as the baseline year not only fails to adequately credit states which made substantial reductions prior to that year, it ignores other serious problems associated with using just a single year to establish the baseline. For example, 2012 does not accurately reflect historical emission levels because the high use of natural gas during that year was reflective of record low natural gas prices. In addition, using a single year as a baseline rather than, for example, a three-year average, substantially increases the risk of having the baseline inaccurately represent past emissions, as is exactly the case EPA's use of 2012 as a baseline creates. EPA has since proposed alternatives to using 2012 as a single baseline in its NODA, which we respond to in a separate submission to the docket.

- Compliance costs. As detailed in the attachment, PSCW estimates that the costs to comply with EPA's proposal over the compliance period range from $3.3 to 13.4 billion. These estimates are preliminary, based on our current understanding of the proposal, and could change depending on alterations EPA makes in the final rule. As highlighted in a previous letter to you from Governor Walker, we are very concerned the costs of EPA's proposal will threaten our most reliable energy source and damage our ability to provide affordable energy to our citizens and manufacturing-based economy.

- Lack of state agency authority. One of the major flaws in EPA's proposal is that it assumes state environmental agencies have the ability to include in state plans methods of compliance over which the agencies have no control. For example, the Wisconsin Department of Natural Resources has no authority or control over which plants are required by regional transmission organizations to dispatch electricity. Similarly, the amount utilities must spend on energy efficiency programs, and the stringency of the state RPS, are determined by the Wisconsin legislature. Other aspects of these programs are the responsibility of the PSCW, which is not responsible for the 111(d) plan. Finally, no state agency has authority to mandate continued operation of a nuclear facility.

- Electric reliability. EPA has not adequately performed sufficient analyses to demonstrate that its proposal will ensure reliability of the grid in Wisconsin. We are particularly concerned that, in the absence of a robust coal-fired fleet, natural gas plants currently used for peaking may not be able to support the electric load.

- Receiving credit for renewables purchased from out-of-state. Pursuant to Wisconsin's state RPS, renewable energy purchased from out-of-state may be used to meet the RPS requirements. Wisconsin utilities have built, own, or operate almost 400 MW of wind energy in other states and have long-term agreements to purchase even more out-of-state renewable power. EPA must establish clear, legally-based guidelines to allow states that own renewable generation in another state, or purchase such generation, to claim compliance credit for that generation. This approach is consistent with how renewable aspects of generation have been treated for many years.

- Consideration of biomass fuels. Biomass is an extremely important renewable energy source to Wisconsin. 46% of the state's land area is forested, and the sustainable use of these forest resources supports many industries, including energy production. Under state law, biomass is allowed to be credited towards meeting RPS requirements. Therefore, EPA should treat biomass differently from fossil fuel CO_2 emissions and consider biomass to be carbon neutral for compliance with the rule.

- Time allowed for submission of state plans. Wisconsin's legislative and regulatory processes require over two years to implement simple, noncontroversial rules. Given the amount of attention this proposal has received, it is unrealistic to expect the state to submit a complete plan within EPA's proposed timeframes. EPA must provide more time, or, at a minimum, provide guidance on what EPA will accept at the plan due date short of a complete and final plan.

- Lack of timely guidance on critical issues. EPA's proposal lacks important details on several critical aspects of the plan, including how to account for biomass fuels in state plans and account for energy efficiency in a consistent way. Other important information, such as examples of how states could convert their rate-based goals to mass-based equivalents, was released by EPA far too late in the comment period to inform modeling or otherwise be adequately analyzed. This lack of timely information on important elements of the proposal is unacceptable. EPA needs to provide all information prior to finalization of the rule and give adequate time for public review so that the states have opportunity to submit comments with the benefit of more complete information.

- EPA must allow comment on the next version of its proposal prior to finalizing. Relatedly, due to the complex and interconnected nature of this rule, we found it challenging to meaningfully comment on any one aspect of the proposal without knowing how EPA ultimately intends to address other parts. Therefore, it's critical that EPA provide the public with the opportunity to comment on the next version of the proposal, *in its entirety*, prior to finalizing this rule.

Finally, we note that neither this letter nor any state comments should be interpreted as the State of Wisconsin's acceptance of EPA's proposal. There are significant legal issues with this proposed rule. Perhaps even more fundamentally, we question whether the use of Section 111(d) via this rule proposal is an appropriate vehicle to dictate energy policy for the state of Wisconsin. We elaborate on the legal issues associated with the proposal in an attachment to this letter.

We appreciate the opportunity to comment on this proposal and look forward to seeing changes addressing our concerns in any final rule.

Sincerely,

Cathy Stepp	P.L. Montgomery	Ellen E. Nowak
Cathy Stepp	Phil Montgomery	Ellen Nowak
Secretary	Chairperson	Commissioner
Wisconsin DNR	PSC of Wisconsin	PSC of Wisconsin

cc:
Bob Norcross, Administrator, Division of Gas and Energy, PSCW
Pat Stevens, Administrator, Division of Air, Waste, and R&R, WDNR

Attachments

DL: 00949888

WISCONSIN'S COMMENTS ON EPA'S PROPOSED CLEAN POWER PLAN
PART 1:
GENERAL COMMENTS

OVERARCHING COMMENTS ON THE EPA'S PROPOSAL AND APPROACH

1. EPA's proposal does not adequately credit states, like Wisconsin, that took early actions to reduce CO_2 emissions from the power sector.

The structure of the proposed rule not only fails to give credit to states, like Wisconsin, that took significant steps to reduce CO_2 emissions from their power sector prior to EPA's proposal, but in many cases, it actually requires larger future reductions from those states than it does from states that have not acted to reduce CO_2 emissions. This results in significant inequities among the states.

Specifically, EPA's use of a 2012 baseline for goal calculation means that many state and utility actions prior to this year are not credited. For example, Wisconsin utilities have closed a number of coal units since 2005 and replaced this capacity with lower CO_2 emitting sources, including natural gas combined cycle (NGCC) units. This has both reduced the average heat rate of the state's coal fleet and reduced overall CO_2 emissions. However, EPA's goal calculation still requires a 6% heat rate improvement from the remaining plants (building block 1) and additionally increases the goal for NGCC units by requiring the replacement NGCC capacity to be ramped up to 70% capacity factor (building block 2). As a result, instead of receiving credit for replacing this coal generation with lower emitting NGCC generation prior to the currently proposed baseline, Wisconsin receives a larger proposed overall goal. The use of an earlier baseline could address some of these issues as discussed elsewhere in our comments.

Additionally, the structure of the building blocks as proposed leads to inequities among states. For example, the use of a renewable energy (RE) growth rate that is a percentage of existing renewable generation leads to larger goals for states that have invested more in renewable energy.[1] Similarly, states that have well-established energy efficiency (EE) programs, such as Wisconsin, are required to reach the overall target of 1.5% savings per year sooner than states that have small or no EE programs, meaning that the early acting states will have significantly larger cumulative savings over the course of the program. These proactive states have also likely already implemented the lowest cost EE measures, resulting in higher compliance costs relative to less active states' going forward. EPA needs to address these inequities. In many cases, these issues have relatively straightforward solutions.

[1] For example, Wisconsin had 5.1% in-state non-hydroelectric renewable generation in 2012 and has a goal of 10.8% renewables by 2029. In contrast, a hypothetical state in the same region that had 1% renewables in 2012 would only have a goal of 2.1% renewables by 2029.

These issues, along with some suggested modifications to address these problems, are discussed in detail in our comments on individual building blocks.[2] Additionally, early actions taken by Wisconsin to reduce power plant CO_2 emissions are discussed in the document on pre-proposal actions.[3]

2. EPA must give states more time to submit state plans and clarify what must be included in state plan submissions.

EPA's proposal allows for additional time for submission of state plans in certain cases (a one-year extension for individual state plans and a two-year extension for multi-state plans). This time period is insufficient and EPA must provide states with additional time to submit plans. The Wisconsin administrative rulemaking process alone takes over two years to complete for simple, noncontroversial rules. Given the amount of planning, stakeholder engagement, and potential coordination with others states that will be required in developing this state plan, we anticipate that formulating a state plan followed by incorporation into state rules will take at least four years to accomplish in Wisconsin. Therefore, submission of a complete plan, including the required regulatory and statutory changes, by EPA's deadlines is unrealistic. In addition to reevaluating its proposed deadlines, EPA should also clarify what states must include in a state plan submission, short of a complete and final plan, in order to meet EPA's deadlines and be in compliance with the rule.

3. State agencies cannot implement a state 111(d) plan based on EPA's building blocks in the absence of explicit authority.

One of the major flaws in EPA's proposal is that it assumes state environmental agencies have the ability to include in state plans methods of compliance over which the agencies have no control. For example, the Wisconsin Department of Natural Resources (DNR) has no authority or control over which plants are required by regional transmission organizations to dispatch electricity. Similarly, the amount utilities must spend on energy efficiency programs, and the stringency of the state RPS, are determined by the Wisconsin legislature. Other aspects of these programs are the responsibility of the Public Service Commission of Wisconsin (PSCW), which is not responsible for the 111(d) plan. Finally, no state agency has authority to mandate continued operation of a nuclear facility.

Moreover, this rule also impinges on policies that have been established by the Wisconsin legislature. As such, any plan developed by the state would likely require state legislative action.

[2] See Part 2: Comments on Building Blocks.
[3] See Part 4: Wisconsin's Pre-Proposal Actions to Reduce CO_2 Emissions from the Power Sector.

4. EPA must ensure that sources will not trigger New Source Review requirements when making modifications to comply with the Clean Power Plan.

EPA is requesting comment on whether, with adequate analysis and support, the state's 111(d) plan could include a provision that sources would not trigger New Source Review (NSR) permitting requirements when complying with the standards of performance included in the state's plan. EPA has indicated that its concern lies primarily with increased emissions from more utilization of generators after physical or operational changes for heat rate improvement (HRI). EPA has further indicated that states may exercise potential flexibility in their 111(d) plans to require operational and/or emissions limitations in order to address this issue.

EPA should not set standards under one rule requirement that create the risk of triggering permitting requirements under another rule, such as NSR. The HRI activities at a source may indeed increase its utilization, as determined by the ISO, due to a lower cost for electricity production relative to other EGUs, but this increased utilization would be beyond the control of the EGU owners/operators. EPA should ensure that sources with projected emission increases due to increased utilization after implementing HRI requirements do not trigger NSR requirements. Allowing states to evaluate HRI on a unit-by-unit basis, as indicated in our comments on the building blocks, could also help address this issue.[4]

Also, as indicated in our comments on the building blocks, EPA's evaluation of increased utilization of NGCC units in building block 2 should account for existing permit or physical operating restrictions.[5] Some of these restrictions may include limitations on operating hours, fuel use or limits on water usage. In some cases, removing these restrictions may trigger NSR review. EPA should ensure that sources with projected emission increases due to increased utilization do not trigger NSR requirements.

5. The timeline EPA established for states to achieve their alternate emission reduction goals is not realistic.

States need to have the full proposed compliance period, through the end of 2030, to achieve their goals. This time will minimize compliance costs and allow states to prudently plan for these significant changes to the power sector, many of which require considerable lead time due to planning, permitting and construction time frames and could not be accomplished by 2025 as required by the alternate goals.

6. EPA must demonstrate that compliance with the rule will not disrupt electrical reliability.

Maintaining reliability of the grid is a critical element in successful implementation of this rule. Understanding the integrated transmission and generation system while also recognizing the different attributes of generation assets is essential when assessing potential reliability impacts. EPA has not

[4] See Part 2: Comments on Building Blocks.
[5] See Part 2: Comments on Building Blocks.

provided a complete analysis of how grid reliability can be maintained if the plan's building blocks are applied as proposed. Wisconsin currently receives 60% of its electrical generation from coal and is therefore very concerned about the proposal's impact on statewide reliability.

First, from the perspective of system reliability, the Integrated Planning Model (IPM), used by EPA to evaluate the building blocks and whether goals are achievable, uses less robust data than that possessed and used by the Midcontinent Independent System Operator (MISO). For example, MISO has performed studies of potential retirements and resulting resource adequacy due to the Mercury and Air Toxics Standards.[6] These studies included information about firmness of interstate pipeline deliverability for gas-fired units, plans for replacement of units, and also consider the electrical grid location and network deliverability of units expected to be retired. In contrast, the IPM modeling used by EPA does not appear to consider any of these very fundamental factors.

Wisconsin encourages EPA to engage Regional Transmission Organizations (RTOs), Independent System Operators (ISOs), and the North American Electric Reliability Corporation (NERC) to assist in modeling the impacts of the rule on electric reliability, as well as evaluating the natural gas transfer and storage capacity requirements needed under this proposal. In addition to using more sophisticated models, these organizations also have planning expertise that could better inform EPA's analysis. EPA should also fully utilize the resources and expertise of the Federal Energy Regulatory Commission (FERC) in assessing the proposal's potential impact on reliability.

EPA's system modeling should also evaluate the rule's impact on the generation reserve margins and understand what resources will be called on to meet those reserves. If combined cycle units are utilized more as base load resources, as suggested in EPA's building block 2, they may not be available to ramp up quickly to fill a need for energy. Simple cycle units may be required to fill that need because coal-fired units are not able to respond as quickly to load changes given their base load characteristics. An ISO-based analysis potentially can evaluate how this rule could change the operation of the state's units. We provide additional comments in this regard in our building block 2 comments.

Finally, EPA should provide states a safety valve to ensure the reliability, safety, and security of the electrical system. Reliability events more frequently occur on a local level compared to the broader ISO-level. EPA needs to recognize, and potentially have exception periods or off-ramps for, such local reliability events. Similarly, EPA should recognize that ISOs and RTOs identify "must-run" units that are required to run to ensure grid reliability; exceptions or off-ramps must be provided in plans for these cases as well.

[6] https://www.misoenergy.org/WhatWeDo/EPARegulations/Pages/EPAStudies.aspx.

7. EPA's proposal does not consider stranded costs.

Since 2000, Wisconsin utilities have invested over $3.2 billion in air pollution control equipment and efficiency upgrades for existing power plants to comply with a variety of EPA regulations and consent decrees; Wisconsin must ensure that ratepayers receive a complete return on that substantial investment. EPA's proposal is predicated on, and will result in, the closure of some coal-burning power plants. In some cases, the plants that EPA assumes will be closed to comply with this rule will do so prematurely, before the end of their planned and useful lives. This could leave ratepayers with the stranded costs for a power plant (and associated pollution control equipment) that has been retired.

EPA does not include provisions to avoid stranded costs and it is not clear that the agency considered stranded costs when determining the cost and impact of the rule. Prior to finalization, EPA should analyze this issue, estimate the potential costs, and provide provisions for states to avoid stranded assets when complying with the rule. We offer further details on this issue in our building block comments.

COMMENTS RELATED TO BASELINE AND GOAL CALCULATION

8. EPA needs to reevaluate the use of 2012 as a single-year baseline.

EPA has proposed using a single year (2012) to establish the baseline year for emissions reductions.[7] EPA should instead use a multi-year baseline that is more representative of normal system operation, addresses the considerable year-to-year variability in the power sector, and is more reflective of early actions to reduce CO_2 emissions. Using a single baseline year is problematic for a number of different reasons, and the selection of 2012 as that baseline year is particularly troublesome.

First, using 2012 fails to credit states, like Wisconsin, that took action before that year to reduce their CO_2 emissions via measures such as plant closures, fuel switching to natural gas, installation of renewable electricity capacity, etc. We describe particular actions taken in Wisconsin in a document on pre-proposal actions.[8] By using 2012 as a baseline, these early actions are included in the starting point, and for many of the building blocks, this results in the perverse outcome that states that have already acted to reduce CO_2 emissions are required to do even more going forward than are states that have not taken similar steps.[9] Power sector CO_2 emissions peaked in 2007 nationwide and in 2005 for Wisconsin, largely because many of these emission-reducing measures and programs were initiated or expanded after these years. Use of a multiyear baseline that includes 2005 would therefore credit much of the early action taken by states and utilities.

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[7] We acknowledge EPA has since proposed an alternative to use a multi-year baseline (EPA's Notice of Data Availability, Oct 28, 2014). Wisconsin will provide additional comments on this specific proposal in its response to that NODA.
[8] See Part 4: Wisconsin's Pre-Proposal Actions to Reduce CO_2 Emissions from the Power Sector.
[9] See Part 2: Comments on Building Blocks for additional discussion of this issue.

Second, the use of a single year as a baseline is inappropriate because there is significant year-to-year variability in power system characteristics (EGU operation, renewable electricity generation, weather variability, etc.) that cannot be represented in a baseline based on a single year. Table 1 shows that Wisconsin's final rate-based goal would increase to 1265 lbs CO_2/MWh using a 2011 baseline, a 5% change from the goal calculated using a 2012 baseline (1203 lbs/MWh). Use of a multiyear baseline would average out much of the inter-annual variability in the power sector. If Wisconsin's goal were calculated based on a three year baseline including 2010-2012, our goals would be between those calculated using either 2011 or 2012, as shown in Table 1, and would be more representative of the power sector in the state.

Table 1. Changes in Wisconsin's interim and final goals using three different baselines.[10]

	Wisconsin's interim goal	Wisconsin's final goal
2012 baseline (proposed)	1281 lbs/MWh	1203 lbs/MWh
2011 baseline	1344 lbs/MWh	1265 lbs/MWh
2010-2012 baseline	1332 lbs/MWh	1254 lbs/MWh

Third, in its rulemakings, EPA routinely uses a range of years to determine representative operating levels for EGUs (e.g., the use of the highest three years out of five used for the Clean Air Interstate Rule, CAIR). EPA specifically does this to address variability due to EGUs that are offline for maintenance or installation of operating or pollution control equipment and other variations in loads and fuel use. Accordingly, EPA's current argument that these issues are not important and that one year is adequate to represent EGU operation is inconsistent with EPA's past actions. Further, EPA is requiring compliance demonstrations in 2030 and beyond based on a rolling 3-year average, demonstrating further that the use of a single year baseline is not consistent with compliance for this rule.

Finally, the choice of 2012 is inappropriate because this was a highly unusual year for the power system, unlike any single previous year. Because natural gas prices were at a record low in 2012, that year is not representative of past operating conditions for the power system. Natural gas EGUs were dispatched much more than usual in 2012, and coal units operated at lower capacity, which reduced their efficiency and increased their emissions rates. As a result, the average CO_2 emissions rate at Wisconsin power plants was 4-6% lower in 2012 than it was in either 2011 or 2013. However, emissions rates at coal units in the state were 2% higher in 2012 than they were in either 2011 or 2013 because these units ran less efficiently with decreased usage.[11] If EPA will not extend the baseline back to 2005, EPA should at least include the most recent year of available data in their calculation of state goals. At the time of finalization, this would presumably be 2013, which was a more moderate year than 2012.

For these reasons, 2012 is a poor and unsupported choice for a baseline year. EPA should use instead a multi-year baseline that includes the year 2005 to credit early action and should allow states to adjust this baseline to account for specific actions back to 2000.

[10] We did not calculate a baseline that includes the year 2005, as the large number of changes made in the power sector since that year make it difficult to predict how EPA would calculate such a baseline.
[11] See Figure 1 of Part 4: Wisconsin's Pre-Proposal Actions to Reduce CO_2 Emissions from the Power Sector.

9. EPA must adjust Wisconsin's baseline to account for the May 2013 closure of Kewaunee Nuclear Plant.

Kewaunee Nuclear Plant, which provided 7.3% of Wisconsin's electricity generation in 2012, closed in May of 2013, resulting in increased generation (and emissions) from fossil generators working to fill the void. EPA must adjust Wisconsin's 2012 baseline to account for the replacement of the retired, carbon-free generation from Kewaunee. We discuss possible approaches EPA could take to this adjustment in our Technical Corrections document.[12]

10. EPA should eliminate state interim goals or, if not, phase in building blocks 1 and 2 over the entire compliance period.[13]

As proposed, EPA assumes states can completely achieve building blocks 1 and 2 by the year 2020, which makes the interim goal for the early part of the compliance period (starting in 2020) unreasonably strict. Under the proposal, Wisconsin would need to achieve 40-50% of the state's total emissions reductions by 2020 – just a few years after state plans are due. As we discuss in our building block comments,[14] it is unrealistic to assume states and utilities can make these changes this quickly, and attempting to do so could negatively affect the reliability and cost of the electric system. The Midcontinent Independent System Operator (MISO), the ISO that handles dispatch and reliability for the region, has also expressed concern that the interim goals as proposed would create resource inadequacy and reliability problems for the region.[15] While it is true that states have ten years to meet the interim goal, the likely impossibility of meeting it in the early years will require states to enact unreasonably strict limits in the latter years. In addition, assuming full compliance with blocks 1 and 2 by 2020 in calculating the goal entirely ignores the practical matter that plan development will require substantial time following EPA's final rulemaking. Further, utilities will need ample time to seek construction permits from WDNR, authorizations by the PSCW, perform construction and demonstrate compliance with blocks 1 and 2.

EPA should eliminate the numerical interim goals and instead require states to demonstrate that they are making reasonable progress towards their final goals between 2020 and 2030. This approach would be similar to the state demonstrations of rate of progress (ROP) already required under other parts of the Clean Air Act and would rely on state determination of intermediate goals as part of their state plan. Alternatively, if EPA chooses to retain the interim goals, they should allow states to phase in building blocks 1 and 2 over the 10-year compliance period. This would be consistent with the construction of building blocks 3 and 4, which are phased in over the compliance period, and would create a more realistic and achievable glide path for states to follow to reach their final goals.

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[12] Part 3: Technical Corrections.
[13] See separate comments submitted by Wisconsin into the docket on the alternative approaches to handling the interim goal presented in EPA's Notice of Data Availability (79 FR 67406, November 13, 2014).
[14] See Part 2: Comments on Building Blocks.
[15] Presentation given by John Bear of MISO at the Organization of MISO States (OMS) Meeting, October 21, 2014.

11. EPA should allow states to adjust their baseline and goals, especially any mass limits, in the future to reflect unexpected changes in the power sector.

State power sectors may undergo profound, unexpected changes after state plans are developed, such as reduction in hydropower generation due to a major drought, increased electrical demand due to unanticipated economic growth, or changes in state laws regarding RE and EE programs. EPA should allow states to adjust their baselines and goals to ensure that state goals are as reasonable and flexible as possible and take changes to the power sector into consideration.[16] This issue is especially important for states that choose to comply via a mass cap. Given the impossibility of accurately predicting anything a decade into the future, it is essential that EPA allows these states the option of adjusting their mass-based goals if the projections of energy demand or generation made when crafting the plan prove to be inaccurate.

In addition to making it more difficult for a state to comply with a no-longer-appropriate mass limit, failure to adjust mass limits could lead to serious distortions in dispatch of generation within a region and make it challenging for neighboring states to meet their own limits. This problem would likely be most severe when neighboring states comply with different types of goals (i.e., mass- versus rate-based). For example, if one state has an overly restrictive mass cap and a second state, a neighbor of the first, complied via a rate-based standard, dispatch might be diverted to the second state rather than in the state whose EGUs were approaching their mass caps. This would require the second state to take additional, unplanned measures (RE, EE, etc.) to balance the increased CO_2 emissions and comply with their rate-based goal and may not lead to lower CO_2 emissions overall.

Ideally, EPA would allow states to adjust their baseline and goals at any time when they can demonstrate a reasonable need to do so. However, at a minimum, EPA should allow states to either adjust their goals periodically or demonstrate that their goals are still appropriate. Wisconsin successfully followed a similar approach to implementation of NOx allocations under the Clean Air Interstate Rule (CAIR) and found that reallocating NOx allowances within our budget every five years provided additional certainty to utilities and allowed them to meet more reasonable limits.

12. States should be able to propose their own mass-based emissions goals.

EPA should allow states to propose mass caps that are comparable to their rate-based goals. As part of this, states should have appropriate flexibility to determine how to make this conversion, including how to handle different measures under the mass-based goal. For example, states should be able to choose how to treat new natural gas combined cycle (NGCC) units under a mass cap.

[16] See, for example, the discussion of the need to be able to adjust energy efficiency goals in Part 2: Comments on Building Blocks.

13. States must be able to account for demand growth in projecting mass limits for existing power plants through 2030 and beyond.

EPA states that any mass-based limit must be equivalent to the rate-based goals determined by EPA for states. In order for this to be true, states must be able to project growth in electrical demand when making this conversion. The rate-based form of the goal doesn't place any limits on electrical demand, so this demand may continue to grow significantly and may be met by any combination of existing and possibly new units, as long as the state can meet its rate goal. Therefore, EPA must allow states to project demand growth for existing units for the entire compliance period (extending beyond 2030) when converting to mass-based limits.

EPA stated in its June 2014 proposal and accompanying documentation that states may project growth when making the rate-to-mass calculation. As discussed above, Wisconsin believes this is an essential part of any equivalent rate-to-mass conversion. However, the language in these documents was unclear about how to apply the projected growth in calculating an equivalent mass cap. EPA's November 13, 2014 TSD on translating state-specific rate-based CO_2 goals to mass-based equivalents also failed to provide this clarity. Neither of the scenarios discussed in EPA's November TSD allows for growth for existing units – one scenario projects no growth for existing units, while the other assumes that all growth will be taken up by new units, which will be regulated under the mass cap. Neither of these scenarios is fully equivalent to the rate-based standard.

14. States must be able to determine the most appropriate growth rate to apply to EGUs in their state.

The ISOs and RTOs are in the best position to forecast future growth within their regions. EPA should allow states to rely on these organizations or other sources for any needed growth rates and should not require states to use EIA growth rate estimates.

15. EPA should correct a discrepancy between the total sales numbers for states given in the supplemental notice and that used in the original proposal.

The sales numbers (corrected for transmission losses) listed in the data file accompanying EPA's November TSD do not match those used in calculating state goals in the June 2014 proposal. For Wisconsin, the data file on state goal calculation accompanying the original proposal listed this number as 73,988,479 MWh, whereas in the November TSD data file, this value is listed as 74,765 GWh (74,765,000 MWh). EPA should correct this discrepancy.

COMMENTS RELATING TO COMPLIANCE

16. EPA should retain compliance flexibility in the final rule.

We encourage EPA to maintain in the final rule the compliance flexibility provided to states. We also encourage EPA to add additional compliance options, such as the use of combined heat and power (CHP) systems, which are highly efficient and clean approaches to generating power and thermal energy from a single fuel source.

However, as we discuss in our comments on the building blocks, the goals EPA set for states are too stringent, which leaves states with few options to comply with the regulation. If EPA were to finalize the proposed goals without further modification, many states would in fact have very little actual flexibility in how to comply with their goal, if in fact they could comply at all.

17. EPA should strongly consider providing the infrastructure for tracking and trading systems that states could use on an "opt-in" basis.

Upon issuing the final rule, we strongly encourage EPA to provide the infrastructure for CO_2 and MWh tracking and trading systems that states can choose to use for compliance with this rule. Such infrastructure could be similar to the system that Clean Air Markets Division (CAMD) provides now for tracking allowances under the acid rain, NOx SIP call and CAIR/CSAPR programs. This system is already used to track CO_2 emissions from power plants. The states could then choose to structure programs to allow trading that utilizes this infrastructure.

18. EPA should be flexible when considering regional approaches to compliance.

EPA's proposed approach for states participating in a regional compliance effort, in which state rate-based goals are averaged to give a shared, regional goal, is unlikely to work. It is difficult to perceive why a state with less stringent goals would be willing to join a regional plan if it resulted in their goals becoming more stringent, again highlighting the major inequities created by the form of this proposal. However, there are a number of other approaches states could pursue to meet their state goals via regional cooperation. Given the complexity of the rule, states will likely need several years to fully examine their options for regional cooperation and to compare these approaches with state-specific compliance options. At the end of this time-consuming process, states may still decide to comply via strategies they can apply within their state boundaries. However, states that have seriously examined regional compliance options should still qualify for the extension for completion of their state plans. States should receive the longer time period to develop state plans so long as they demonstrate that they are actively engaged in a process with other jurisdictions to consider multi-state coordination and that they are developing multi-state or individual state plans that contemplate such coordination.

19. States should be allowed to bank emissions reductions occurring from 2013-2019 due to measures installed during that time period for use during the compliance period.

As proposed, states and utilities have an incentive to delay implementing some emission reduction measures until the compliance period, which could lead to a relative increase in CO_2 emissions. To avoid creating this perverse and unintended consequence, EPA should allow states to bank credits from reductions that occur during the period between the baseline year and the compliance period (e.g., 2013-2019) due to measures installed during this time period. These measures could include, but are not limited to, plant retirements, fuel switching, new renewable energy installations and newly installed energy efficiency measures. Further, states should not be required to demonstrate that these reductions were "additional" to what would have occurred anyway (i.e., without the Clean Power Plan), as long as the measures reduce CO_2 emissions. Under Wisconsin's RPS, the ability to bank credits proved essential in allowing utilities to meet their individual requirements each year as well as meet the overall statewide goal two years ahead of schedule.

20. State programs should not become federally enforceable if they are used for compliance with the Clean Power Plan.

States must be able to use state-run programs, such as those for energy efficiency and renewable energy, for compliance with the rule without the risk of EPA assuming any authority or control over state programs if they fail to deliver the anticipated emissions reductions. Instead, if these programs fall short of their goals, the state should be responsible for attaining those emissions reductions in another manner. Such an approach is currently used by states that include contingent reduction plans in criteria pollutant SIPs to be used in the event a shortfall in reductions occurs within the core approach. This approach allows states to retain authority of all state programs used for compliance with the Clean Power Plan while assuring the program objectives will be met even if the planned approach falls short.

21. EPA should provide states maximum flexibility to decide how to use new facilities for compliance with 111(d).

The proposed rule allows states to count lower emissions from new facilities such as new NGCC units for compliance with the 111(d) requirements. EPA should ensure that states have enough information to allow them to evaluate the use of these new sources for compliance, including understanding any issues caused by interactions with 111(b) requirements. However, EPA should allow states to ultimately decide how to handle these facilities in their state plans.

For example, if a state chooses to count new NGCC units under its mass cap, the state should be able to include both the generation and the emissions from these units in the goal, in parallel to how these units would be treated under a rate-based goal. In order to accomplish this, the state must be able to recalculate its mass cap to account for the additional generation from the new NGCC units, and the emissions would also count towards the limit. The choice of how to handle these new units must reside with the state. Additionally, EPA should not automatically transition "new" facilities constructed under the proposed 111(b) regulation into the currently proposed 111(d) regulation in the situation where the 111(b) rule is replaced or updated.

22. EPA should allow full credit for useful thermal output towards compliance with the rule.

EPA requests comment on a range of two-thirds to 100 percent credit for useful thermal output (UTO) from cogeneration plants and combined heat and power plants. EPA should provide a compliance methodology that allows up to 100 percent credit for useful thermal output from these facilities where it can be demonstrated. Several Wisconsin facilities, including West Campus and Whitewater NGCCs, provide useful thermal energy for heating/cooling or industrial processes. Such facilities should be provided the opportunity to show up to 100% use of the thermal energy.

23. EPA should address issues caused by having some states comply via rate-based plans and others via mass-based approaches.

Having a mix of compliance approaches in different states could create a number of problems. In addition to the possible distortions in dispatch between and among states complying with a mass limit and those complying with a rate-based standard, discussed in comment 11, having a mix of approaches could also lead to double-counting of some measures and under-crediting of others. For example, a portion of the RE generated in a state that complies with a mass cap, but owned and operated by a utility in a second state that complies with a rate-based goal, could be credited to both states. EPA should address these potential interstate issues.

24. EPA should ensure consistent monitoring and recordkeeping requirements and rule definitions under multiple federal rules.

The interaction of multiple permitting requirements – the CO_2 NSPS under 111(b) for new sources, the modified and reconstructed proposal under 111(b), and the existing source proposal under 111(d) – will be complex. EPA should assess the monitoring and recordkeeping of various regulatory programs, and consistently use the monitoring and recordkeeping protocols currently in place to demonstrate compliance with CO_2 regulations in order to avoid redundant or conflicting requirements. EPA should also correct any inconsistencies in rule definitions among the various rules, such as the definitions of "facility", "affected source", and what constitutes a "reconstruction". Consistent rule definitions are especially important in the permitting process for facilities.

25. States should be able to obtain credit for air quality co-benefits.

Wisconsin recognizes that EPA's proposal will likely result in co-benefits for criteria pollutant emissions such as NOx, VOCs, and SO_2. EPA should ensure that any reductions in these emissions resulting from this rule can be counted by states towards meeting their statutory and regulatory requirements for criteria pollutants.

26. EPA needs to describe what a 111(d) Federal Implementation Plan would include.

Under EPA's proposal, states that fail to submit a plan implementing EPA's rule by the applicable deadline are subject to EPA imposing a Federal Implementation Plan (FIP). Neither EPA's proposal, nor any subsequent public explanation, has elucidated what the contents of a FIP would or might contain. Concurrent with finalizing this rule, EPA needs to describe its understanding of what a FIP would include, so that this information can be considered in state planning processes.

27. Review of state 111(d) plans needs to be conducted in a consistent manner that minimizes the differences in interpretation across EPA regions.

Historically, EPA has not consistently implemented regulations across its regions. However, given the new and novel approaches inherit to this proposal, EPA needs processes in place to ensure consistent, reliable interpretations and standards when implementing this rule. Given both the complexity of the proposed rule and the multitude of compliance pathways potentially available, state plans need to be evaluated consistently by the different EPA regional offices. EPA needs to ensure that a particular compliance approach, rate-to-mass conversation methodology, or other regulatory interpretation found by an EPA regional office to be acceptable for one state should be acceptable for all others.

28. EPA should allow RE used to comply with state renewable portfolio standards (RPSs) to qualify for compliance.

Any RE that is accepted by a state RPS should qualify for compliance with EPA's proposal. As part of this, EPA should allow states to use evaluation, measurement and verification (EM&V) approaches already developed for their RPS programs to measure and verify avoided emissions under the Clean Power Plan. EPA should also develop minimum and reasonable EM&V requirements and allow states to demonstrate that their programs meet these requirements, as EPA has planned.

29. Biomass-based energy should be considered carbon neutral and count towards compliance with the rule.

EPA should consider biomass to be a carbon neutral energy source and should be consistent in its treatment of biomass for goal setting and compliance purposes. Currently, biomass counts as carbon neutral in setting the goal, but EPA has deferred any decision about how biomass will count for compliance until completion of their draft Biomass Accounting Framework. This uncertainty is very problematic for states like Wisconsin, as is the possibility that EPA may not fully credit biomass as a compliance option.

Biomass is an extremely important energy source for Wisconsin, which has no naturally occurring fossil fuels and smaller wind resources than its neighbors. Utilizing biomass as an energy source not only provides environmental benefits, including displacing fossil fuel generation, but also helps develop Wisconsin's economy and create jobs. Wisconsin utilities have installed, or converted to, over 132 MW of biomass-fired generation. Also, 19% of the renewable electricity used to comply with the state RPS and sold via green purchasing agreements was derived from biomass in 2013. Most of this biomass power was generated within the state.

Further, Wisconsin's RPS is premised upon the ability of the state to use biomass power for compliance. Without this resource, the state might have set a lower RPS standard; therefore, under EPA's current proposal, Wisconsin's emissions reduction goal is more stringent because of our biomass generation. If EPA does not allow the state to use this generation towards compliance, then the state's goal would be overly stringent and inequitable. EPA should instead count all biomass-derived generation as carbon neutral and eligible to fully count towards compliance. Alternatively, if EPA does not count biomass as carbon neutral for compliance, they must, at a minimum, adjust our state goals accordingly.

Wisconsin also believes that the states are in the best position to determine whether biomass should be considered carbon neutral based on factors specific to each state or region. States should be able to certify CO_2 neutrality for biomass harvested under state or federal sustainable forestry practices, harvested as part of a fire hazard reduction activity or as pre-commercial thinning, slash or tree residue, collected during clean-up from natural storms or disasters, or obtained from the demolition of buildings and removal of invasive trees by municipalities. Energy derived from, among others, industrial and commercial process biomass waste, municipal solid waste, landfill gas, anaerobic digester gas, and wastewater treatment plant gases, should also qualify.

If EPA will not let states determine the carbon neutrality of biomass, EPA must complete its Biomass Accounting Framework without additional delay and prior to issuance of the final rule so that states know how their biomass power will qualify under the regulation. It is absolutely essential for states like Wisconsin with significant biomass resources to know with certainty how these resources may be used for compliance. Treatment of biomass will affect how we craft our state plan, so it is important that EPA provides certainty on this issue before the rule is finalized.

30. EPA should credit renewable energy from biogas for the destruction of methane in using this fuel.

Biogas from farm dairy digesters and other sources is an important energy source in Wisconsin that provides a number of environmental benefits. In developing its Biomass Accounting Framework, EPA should recognize that biogas from anaerobic digesters processing manure and other wastes, as well as from landfills, actually provides greenhouse has reductions in that the digesters capture and destroy waste methane, which is a much more potent greenhouse gas than is CO_2. EPA should give biogas credit for this methane destruction as well as for displacing fossil fuels used to generate electricity.

31. Biomass CO_2 emissions should not be regulated under the Clean Power Plan.

The previously proposed CO_2 New Source Performance Standard (NSPS) for power plants will regulate EGUs combusting biomass fuels any time fossil fuels comprise more than 10 percent of the heat input to the unit. This situation is common, as the most efficient and reliable approach is to burn biomass in conjunction with fossil fuels. Biomass CO_2 emissions should not be regulated under either the NSPS or the Clean Power Plan regardless of what portion is fired with coal or other fossil fuels. Doing so will only penalize the use of biomass energy when there are many biomass fuels, including those harvested under sustainable forestry practices, that are beneficial in reducing CO_2 impacts fossil fuels, as discussed above.

32. EPA should allow states to use existing tracking systems such as M-RETS to track RE used for compliance with the rule.

Renewable energy tracking systems (such as M-RETS) are well-established and have been used for compliance with state RPS programs for years. Such tracking systems have established procedures to avoid double-counting of RE and to verify reported data. EPA should allow states to use existing tracking systems to track RE used for compliance with the rule.

33. Hydropower that is newly available to U.S. states, and all incremental hydropower generation, should count towards compliance.

Additional hydropower generation from Manitoba will be accessible to the U.S./Wisconsin in 2020 following completion of a new transmission line, subject to approval of that line. This newly available hydropower should not count as "existing" hydropower for compliance, which is excluded from consideration under the proposed rule. Instead, this power should qualify as carbon neutral generation for compliance with the rule. In addition, EPA should finalize its proposal that all incremental (i.e., additional) hydropower, both foreign and domestic, can count towards compliance.

34. EPA should not scale down EE savings for states that are net importers of electricity (such as Wisconsin) to account for the fact that some of the savings from EE measures in these states may actually occur out of state.

In 2012, Wisconsin's Focus on Energy program spent $91 million on the EE program. If EPA only credits us with 83.97% of our savings as proposed, then the state is not being credited for $15 million in investments in just that year. EPA should grant the full credit for avoided emissions due to the EE measures to the state that instituted and paid for the measure. This is a parallel approach to the one Wisconsin is recommending for renewable electricity in which the state that pays for the renewable generation receives credit for that generation. Similarly, EPA should not give net exporter states credit for EE measures instituted in and paid for by other states, even if they result in reductions that occur in the exporting state.

35. EPA should allow EE measures installed under Wisconsin's Focus on Energy program to qualify for compliance.

EPA should develop minimum and reasonable EM&V requirements and allow states to demonstrate that their programs meet these requirements. Focus on Energy has a well-established and rigorous approach to determine the avoided emissions from EE measures and could serve as a model for EPA's EM&V requirements. Both PSCW staff and the program's evaluation contractor, Cadmus, are willing to prepare materials and/or consult with EPA to help develop these requirements. EPA should allow Wisconsin to use these previously established methods to verify avoided emissions. EPA should also allow other types of EE programs, including voluntary programs, to qualify for compliance as long as they meet the same, rigorous EM&V procedures.

36. EPA should finalize their proposal to count EE measures installed before 2020 towards compliance as long as these measures are still in place during the compliance period.

All energy efficiency measures that are still in place during the compliance period will reduce emissions during that period and thus should count towards compliance, whether or not they were installed before or after 2020. EPA currently proposes that measures installed after publication of the proposal may count towards compliance. EPA should additionally allow measures installed after the baseline year(s) to count towards compliance since these measures would not have been included in the baseline yet would reduce emissions during compliance. If EPA continues to use 2012 as a baseline, this would allow measures installed from 2013 to 2019 to count towards compliance. As noted previously, EPA should provide for banking of these reductions from the baseline year(s).

37. EPA should consider savings from building codes programs eligible for compliance.

EPA should allow savings from building code programs to be eligible for compliance with the rule. PSCW has authorized Focus on Energy to develop plans for a building codes program for potential implementation in the coming years. Focus agrees with EPA that EM&V protocols for building codes programs do need further development, and will make that a focus of any program they may implement by integrating evaluation practices with the well-established and rigorous approaches it already uses for other programs.

38. EPA should allow reductions in generation from utility load management programs to count towards compliance.

Utility programs to reduce peak demand also result in reductions in generation, and these reductions should count towards compliance with the regulation. EPA should issue guidance explaining how these programs could be used under this rule and detailing the EM&V procedures required for such compliance.

39. EPA should allow states to determine how to treat emissions reductions from other EE measures for compliance, including private sector EE projects.

Performance contracting projects and other energy service company (ESCO) projects can achieve significant reductions in generation, but implementation of these projects is largely independent of state environmental and energy regulators. In addition, other types of non-utility EE projects can also reduce power sector CO_2 emissions, such as those run by state energy offices. Accordingly, EPA should allow states to determine whether and how any emissions reductions from these projects may be used towards compliance with a state plan. In order to ensure that this avoided generation is properly accounted for, EPA should also establish clear guidelines establishing how such non-utility based projects can qualify for compliance and what EM&V procedures they must follow.

40. EPA should allow states to count gross EE savings (not net savings) toward compliance with the rule.

Energy efficiency savings can be measured as "gross" or "net" savings, where gross savings include all savings from measures installed under a program, and net savings represent only those measures that are due directly to the program excluding measures that would have been installed anyway (without the program in place). Gross savings are the appropriate measure under this rule, both because this rule is focused on actual emission reductions without attributing motivations (or "additionality") to the measures and because determination of net savings is somewhat subjective.

WISCONSIN'S COMMENTS ON EPA'S PROPOSED CLEAN POWER PLAN
PART 2:
COMMENTS ON BUILDING BLOCKS

GENERAL COMMENTS ON EPA'S BUILDING BLOCK APPROACH

1. EPA's proposed Best System of Emission Reduction (BSER) should not include building blocks 2 through 4.

EPA's proposed BSER for greenhouse gas emissions from electricity generating units (EGUs) is established for the entire electric generating system across the nation, instead of distinct sources of emissions. EPA's consideration of the entire electrical system when setting the BSER is a significant deviation from the historical approach of reducing emissions from power plants and is inconsistent with the intent and purpose of Section 111 of the Clean Air Act (CAA). Every existing source guideline promulgated by EPA has been based on measures that the regulated source can incorporate into its design or otherwise implement on its own. Under EPA's proposal, only building block 1 (heat rate improvements at EGUs) meets that standard. In contrast, building blocks 2 through 4 of EPA's proposal rely on "outside the fence line" measures that are beyond the control of regulated sources. This is contrary to the language, intent, and historical application of Section 111(d), and therefore should not be included as BSER under this proposal.

2. EPA's use of different approaches to determine the four building blocks is arbitrary and unsupportable.

For each building block, EPA applies inconsistent approaches to determine state interim and final goals. Building block 1 applies a national-level heat rate improvement to each coal-fired plant, regardless of the ability of an individual plant to realize these gains. Building block 2 similarly applies a nationally-derived capacity goal for combined cycle plants. In contrast, for Building Block 3, state renewable goals take a regional approach, being driven by average renewable portfolio standard goals found in states arbitrarily grouped together by EPA. Finally, for Building Block 4, energy efficiency goals are set using yet another method, as they are based on the incremental savings rate targeted by a handful of leading states.

The use of differing approaches presents several problems. First, it is arbitrary and inconsistent. EPA makes no compelling argument why it is appropriate to use different approaches for different building blocks.

Second, it ignores a critical aspect of setting BSER: namely, what is achievable in practice for the specific type of units being controlled. This is inconsistent with EPA's historical approach to implementing section 111(d), which is to evaluate what has been demonstrated to be achievable by a unit type.

For this and other reasons, Wisconsin believes EPA should use a state-specific, bottom-up approach that relies on state-specific data when determining BSER under this rule (see comment 4). However, should EPA maintain its proposed approach, the methods used to determine and apply the building block goals must be adjusted so that they are consistent, logical, and congruent with historical applications of 111(d).

3. EPA's proposal ignores interactions among the building blocks and fails to demonstrate Wisconsin's ability to achieve its emission reduction goals by implementing all four building blocks in the proposed manner.

A fundamental failure of EPA's methodology for setting the BSER is that it does not recognize that the four building blocks, if applied in the manner the EPA used to set the state's emission goal, actually work against each other in practice. For example, increasing renewable generation requires more capacity to be available to respond to the highly intermittent resources. This load-following capacity has historically been gas, but operating gas units to load-follow reduces their capacity factors and severely curtails their ability to meet building block 2 goals. In addition, increasing in-state gas generation to comply with building block 2 drives coal-fired resources to become load-following (and dispatched at lower loads), thereby reducing the efficiency of the coal fleet and making it impossible to meet building block 1's heat rate improvement target.

EPA claims to have demonstrated that the emission reductions achieved by each building block are independently attainable, and therefore can simply be added together to determine an overall goal (although, as noted below, Wisconsin disagrees with this assessment). However, under the CAA, it is EPA's burden when determining BSER to show that the building blocks, applied <u>simultaneously</u> and in concert, are "achievable" and have been "adequately demonstrated" <u>for each state</u>. EPA has failed to make this demonstration.

EPA has responded verbally to Wisconsin's concerns about achievable reductions attributable to individual building blocks by insisting that equivalent reductions can be achieved in the other building blocks. Such a response not only reflects a fundamental misunderstanding of how BSER is set, but also reflects how little consideration EPA has given to the practical interaction of the building blocks.

Prior to finalizing the rule, EPA must present analysis or modeling that shows the reductions that can actually be achieved when implementing all four building blocks simultaneously for each state, as well as nationally. This analysis should look at the system as a whole in determining the limit for each state. This type of modeling accounts for electricity growth, nuclear plant retirements, and real operation of the electric supply system. In performing this modeling, EPA should also account for constraints identified in our comments, including maintaining operation of major coal-fired EGUs with major investments and maintaining coal-fired EGUs at capacity factors of 50% annually or greater to avoid efficiency losses. The results of this system-wide modeling—of all building blocks together—should then be used to inform how generation will move between states, what generation and emissions are offset by the building block requirements, and finally, the resulting emission targets in each state. Estimating the building blocks and modeling the interactions is necessarily an iterative process in setting the final building blocks.

4. Instead of its proposed approach, EPA should use a state-specific, bottom-up methodology based on actual achievability in each state.

Instead of the arbitrary and inconsistent mix of approaches proposed by EPA, the agency should adopt a bottom-up approach; that is, letting individual states implement the building blocks using state-specific (and, for building blocks 1 and 2, unit-specific) information. This would allow the building blocks to accurately reflect both what a state has accomplished to date and what it can actually achieve in the future. This approach also recognizes what EPA has acknowledged: that each state is starting in a different place and therefore must have a unique reduction goal.

However, unlike EPA's application of the building blocks, which requires asking more of states which have undertaken more carbon emission reduction measures, a state-specific, bottom-up approach would recognize that forward-thinking states that took early action have already picked the "low-hanging fruit" and therefore have less they can reasonably achieve when compared to those that have done little. For example, EPA's heat rate improvement assumption of 6% may well be achievable in states that have not invested in upgrades. However, as discussed in comments on building block 1, this rate is simply not realistic for Wisconsin or other states with regulated utilities that already operate highly efficient plants. A bottom-up approach to setting BSER is the best way to give credit for these early actions and existing conditions.

COMMENTS ON BUILDING BLOCK 1 (HEAT RATE IMPROVEMENTS)

EPA is proposing that every coal-fired electric generating unit (EGU) improve its heat rate by 6%. EPA determined this heat rate improvement (HRI) percentage based on a generic analysis of available measures and not on the actual technical HRI potential of individual EGUs. In fact, an initial assessment indicates that HRI may be limited to less than 2.3% (on average) for the Wisconsin coal-fired EGU fleet. This discrepancy means that EPA must either perform a unit-by-unit assessment of HRI (e.g., take a bottom-up approach when constructing building block 1) or allow the states to perform such an analysis. The methodology behind building block 1 should also account for factors such as remaining lifetime of units, capital investments in the units, and the interaction with other building blocks. The following comments expand on these themes.

5. EPA's analysis does not identify the real technical potential for coal-fired EGU heat rate improvement.

EPA's basic approach to developing building block 1 is flawed. In evaluating HRI, EPA first analyzed heat rate trends over time for EGUs and then separately identified actions that could improve heat rates based on a report by Sargent and Lundy.[1] However, EPA did not directly evaluate to what extent the Sargent and Lundy actions can actually be implemented for any given EGU. In fact, EPA acknowledged that there is no real connection between the HRI actions and an actual implementation potential in determining the 6% HRI. EPA stated that, based on its informal discussions with Sargent and Lundy and other power sector engineering firms:

> "The EPA has found no comprehensive data set on the extent to which specific HRI methods have already been applied at individual EGUs. The EPA believes that many EGU owners consider such information to be confidential."[2]

EPA also incorrectly applies a single HRI percentage to every EGU. This method does not adequately account for differences in HRI potential due to firing different fuels such as subbituminous, bituminous, biomass or other fuels. It also does not account for differences between new and older EGUs, different sizes and configurations of units, and the degradation of heat rate due to operation of pollution control equipment. Under EPA's approach, an EGU has a more stringent emission target simply due to factors which cannot be controlled by the utility. For example, heat rates will be higher (less efficient) when the plant is operating with a full complement of pollution control equipment. In this case, applying the 6% value to the net heat rate will result in a larger HRI action than for an EGU that does not have pollution control equipment.

The flaws in EPA's analysis and resulting potential difference between the 6% HRI assumed by EPA and the real HRI potential as applied to Wisconsin is illustrated in comment 6.

6. EPA must use a "bottom-up approach" in determining HRI for each state and decrease Wisconsin's HRI requirement accordingly.

As noted in comment 5, EPA's analysis is flawed in that it does not represent the actual potential for improving fleet heat rates. Instead, EPA must conduct, or allow states to perform, a unit-by-unit, bottom-up analysis to determine the HRI potential of the EGUs in each state. The results of such an analysis of Wisconsin EGUs strongly supports the conclusion that EPA's assumed 6% HRI is far from achievable in Wisconsin, as described below.

A. <u>Contrary to EPA's assumptions, Wisconsin's coal-fired EGU heat rates have improved over time.</u>

First, Wisconsin's EGU heat rates have not degraded over time. In its analysis, EPA determined that heat rates have degraded for approximately 40% of the coal-fired EGUs in the nation. On this basis EPA concludes that there is potential to improve heat rates in every EGU in the nation. However, EPA's data

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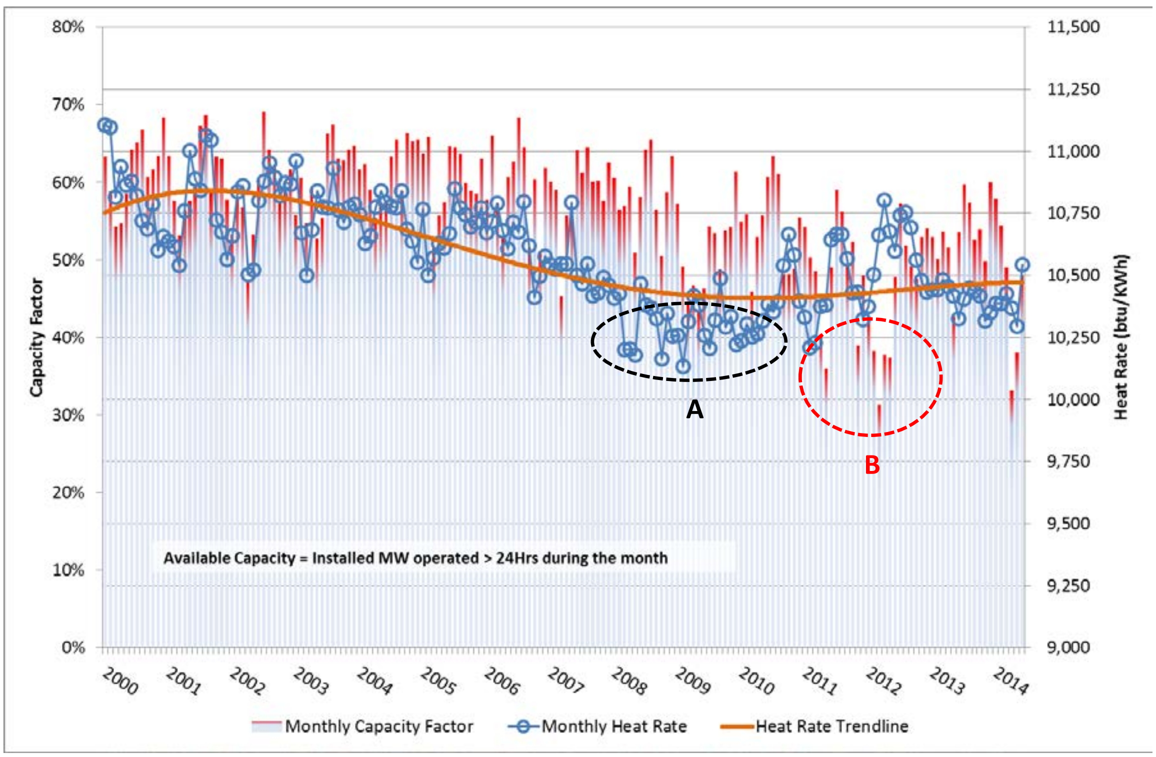
[1] 2009, Sargent and Lundy, *Coal-fired Power Plant Heat Rate Reductions*, SL-009597, project 12301-001, Chicago, Illinois, www.sargentlundy.com.
[2] EPA, 2014, *Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants: Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources: Electric Generating Units. GHG Abatement Measures*, footnote 32.

actually shows that the heat rate for Wisconsin's vintage EGUs[3] has not degraded at all; in fact, it has improved substantially since 2000. This data, plotted in Figure 1, reveals a trend in the early 2000s where the fleet gross heat rate is greater than 10,750 btu/kWh. Since 2007, however, the trend has consistently been below 10,500 btu/kWh. This difference represents a 2% improvement in the fleet gross heat rate.

Looking more closely, from 2008 through 2010 (time period A in Figure 1) the heat rate trend was consistently at or lower than 10,250 btu/kWh. During this time period, the utilization of the fleet remained greater than 50% capacity factor, which is more comparable to the higher capacity factors in the early 2000s. This comparison shows an efficiency gain of 500 btu/kWh—a 4% improvement in the fleet heat rate at capacity factors of 50% or greater.

In conclusion, the Wisconsin coal-fired EGU heat rate, when compared to similar dispatch levels, appears to have improved by as much as 4% over time. This result indicates that there is little additional potential to improve Wisconsin's coal-fired fleet heat rate. This is discussed further in comment 6.B.

Figure 1. Average Heat Rate Trends and Capacity Utilization for Wisconsin Vintage Coal-fired EGUs



[3] "Vintage EGUs." This analysis focuses on coal-fired EGUs in operation since 2000 through 2012 in order to evaluate the potential to implement heat rate improvement for the fleet being considered under the 2012 baseline. The units included in the analysis are: Columbia 1 & 2, Edgewater 3 to 5, Genoa, JP Madgett, Nelson Dewey 1 & 2, Pleasant Prairie 1 & 2, Pulliam 5 to 8, Weston 1 to 3 and South Oak Creek 5 to 8. The analysis excludes the new, highly-efficient Weston 4 (brought online in 2008) and Elm Road 1 and 2 (2010 and 2011, respectfully) coal-fired EGUs. The analysis also excludes EGUs that will be retired prior to 2020.

B. <u>The potential HRI for the Wisconsin coal-fired EGU fleet is substantially less than 6%.</u>

Wisconsin electric utilities are regulated by the Public Service Commission of Wisconsin (PSCW). Through PSCW's oversight, Wisconsin utilities are already incented, and to a large degree required, to maintain and improve heat rates when prudent for the electric ratepayer. As a result, Wisconsin's coal-fired EGUs are already very efficient.

Wisconsin conducted an assessment of the HRI actions included in the Sargent and Lundy report to see which ones were already implemented at individual coal-fired EGUs in Wisconsin. This assessment showed that many of the Sargent and Lundy HRI actions have already been implemented; in addition, this analysis showed that some of these HRI actions are not applicable to Wisconsin's coal-fired EGUs.

The qualitative results of the analysis are shown in Table 1. In this table, an entry for an EGU indicates that some level of HRI has already been completed. The EGUs in Table 1 accounted for more than 90% of the coal-fired electricity generation in 2012 for Wisconsin. This assessment excludes coal-fired EGUs that will be retired or converted to natural gas prior to 2020; this exclusion is appropriate in calculating the HRI for units operating in 2020 (refer to comment 8.A).

Table 1. HRI Actions Implemented at Coal-fired EGUs Prior to 2012 by Wisconsin Utilities.

Category	EGU	2012 Gross Generation (MWH)	HRI Action												
			Neural Network	Intelligent Sootblowers	Air heater and duct leakage	Condenser Cleaning	Boiler feedpump	Cooling tower packing	FGD modifications	SCR modifications	ESP modifications	Turbine Overall / Maintenance	Flue Gas System	Economizer replacement	Acid dew point
New Since 2008	Elm Road 1	602,115	X	X	X	X	X	NA	X	X	X	X	X	X	X
	Elm Road 2	1,639,751	X	X	X	X	X	NA	X	X	X	X	X	X	X
	Weston 4	3,625,282	X	X	X	X	X	X	X	X	X	X	X	X	NA
Vintage Units (Coal EGUs in place prior to 2008)	Columbia 1	3,930,969	X	X		X	X	\	NA	NA	X	X	\	OHR	NA
	Columbia 2	3,825,340	X	X		X	X	\	NA	NA	X	X	\	\	NA
	Edgewater 5	2,196,957	X	\		X	X	NA	NA	NA	X	X	X	OHR	NA
	Genoa	982,144	X	\	\	X	X	NA	NA	NA	X	X	X	OHR	NA
	JP Madget	2,103,104	X	X		X	X	NA	X	NA	X	X	X	OHR	NA
	Pleasant Prairie 1	3,397,014	X	X		X	X	OHR	NA	X	X	X	\	OHR	NA
	Pleasant Prairie 2	2,543,590	X	X		X	X	OHR	NA	X	X	X	\	OHR	NA
	Pulliam 7	129,240	X	X		X	X	NA	NA	NA	X	X	\	OHR	NA
	Pulliam 8	391,430	X	X		X	X	NA	NA	NA	X	X	\	OHR	NA
	Oak Creek 5	866,824	X	X		X	X	NA	NA	X	X	X	X	X	NA
	Oak Creek 6	1,060,146	X	X		X	X	NA	NA	X	X	X	X	X	NA
	Oak Creek 7	1,227,790	X	X		X	X	NA	NA	X	X	X	X	X	NA
	Oak Creek 8	1,217,134	X	X		X	X	NA	NA	X	X	X	X	X	NA
	Weston 3	1,408,456	X	X		X	X	OHR	X	X	X	X	X	ORH	NA

Legend: An "X" represents where the action has been completed, or actions have been taken which achieve equivalent outcomes. An "\" indicates where activity has occurred equivalent to some extent with the HRI action. "OHR" indicates where action has been specifically taken to maintain the heat rate. Utilities have also identified the "OHR" cases as being limited by potential NSR implications. "NA" identifies cases where the action is not applicable to that EGU.

To estimate the actual range of HRI potential of these EGUs, two cases were considered. In the first case, the maximum HRI value was applied to units that had undertaken no HRI actions and the minimum HRI value was applied to units that had partially implemented HRI actions. This method resulted in a total HRI of 0.5% (from the gross heat rate) for the EGUs in Table 1.

The second case is intended to illustrate an upper bound of potential for implementing these HRI actions at Wisconsin units. In this case, the maximum HRI value was applied to EGUs that had not indicated implementation of the HRI action, the average value for each HRI action was applied to EGUs that had partially implemented actions, and the minimum HRI value was applied to EGUs that appeared to already implement the HRI action (to allow that some level of improvement for intelligent sootblowing and turbine maintenance HRI actions could still be achieved at these units). This second, upper bounds case yields a total fleet-wide HRI of 2.3% from the gross heat rate.

These analyses show that the HRI potential for Wisconsin EGUs is well below the 6% presumed by EPA. In fact, the 2.3% indicated by this analysis may still be a value that is beyond the capability of the Wisconsin EGU fleet. It is more likely that an actual achievable HRI value lies closer to 0.5% for Wisconsin coal-fired EGUs. However, it is acknowledged that, given the assumptions made, further analysis is needed to refine these numbers. It should be noted that gross heat rate values were used because of the higher confidence in these values. If the net heat rate were used, as EPA did, the actual HRI potential for Wisconsin EGUs would be even lower.

C. EPA must conduct a unit-by-unit analysis to determine building block 1 and decrease Wisconsin's HRI requirement accordingly.

Our analysis clearly demonstrates EPA's building block 1 presumes actions that will not yield additional HRI for Wisconsin EGUs. To address this problem, EPA must use a unit-by-unit, bottom-up approach to assess the applicability of the identified HRI actions to each EGU and determine a building block 1 value specific to each state. EPA should also allow each state to make adjustments to building block 1 based on what is technically achievable at each EGU. Finally, EPA should decrease Wisconsin's HRI requirement to reflect the results of such a bottom-up analysis; based on the preliminary analysis presented above, the real HRI is anticipated to be lower than 2.3% and may range as low as 0.5% on a gross heat input basis.

7. EPA must change its building block 1 methodology to account for the negative impact on HRI from building blocks 2 and 3b.

EPA is proposing to increase the dispatch of existing NGCC units (building block 2) and require additional renewable energy (building block 3b) to reduce the use of coal-fired EGUs. However, reducing the capacity factor of Wisconsin's coal-fired EGUs will substantially degrade the fleet heat rate (i.e., decrease its efficiency), thereby offsetting any HRI improvement achieved by building block 1.

To demonstrate this effect for Wisconsin, the potential degradation in heat rate was evaluated due to building blocks 2 and 3b by first assessing EGU operation in 2012. For the vintage coal-fired EGUs expected to remain online through 2020[4], our analysis shows the average fleet capacity factor was 57% in 2012, yielding a total generation of 25,280 GWh. Individual EGU capacity factors ranged from 20% to 81%.

Increasing the NGCC fleet in Wisconsin to 70% capacity factor (done to comply with building block 2) results in approximately 7,206 GWh of generation. Removing this amount of generation from the coal-fired vintage EGU fleet reduces the coal-fired fleet capacity factor from 57% to 41%. In some cases, individual EGUs with capacity factors as high as 80% in 2012 fall to below 50%, and in several cases below 40%, due to this shift in generation.

The real impact of building block 2 on EGU heat rates can be seen in Figure 1 (see comment 6). This data clearly shows a strong relationship between a lower capacity factor and decreased heat rate for Wisconsin coal-fired EGUs. When operating at close to 60% capacity factor, the fleet showed the highest efficiency (approximately 10,250 btu/kWh). When the fleet operated at a 43% capacity factor, the heat rate was 10,375 btu/kWh. When the EGUs operated at only a 38% capacity factor for two months in 2012, the fleet heat rates were even worse (10,502 and 10,804 btu/kWh). This shows that the 41% capacity factor resulting from building block 2 could degrade the fleet heat rate by as much as 5%.

Applying building block 2 also resulted in capacity factors for individual EGUs falling into the 30% range. Figure 1 also shows that EGUs operating at this level could experience generation efficiency losses of 7% (or greater) when compared to operating at even a 50% capacity factor.

This type of analysis cannot project the full impact to the system. For example, EGUs may have to operate above load demands simply to be available at certain times for reliability, or to ramp up when needed. This may result in excessive electricity production, which may result in dumping electricity to the grid. EGUs also may simply need to be operated in order to pay-off invested costs. In addition, there will be consequences to fuel contracts, the delivery systems, and overall maintenance and operation of infrastructure and facilities that have not been evaluated here. Finally, our conclusions are conservative in that they likely underestimate the results; because building block 3b (renewable energy) will further displace coal-fired generation, the negative impact on coal-fired fleet efficiency will likely be even greater.

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[4] This analysis includes: Columbia 1 & 2, Edgewater 3 to 5, Genoa, JP Madgett, Nelson Dewey 1 & 2, Pleasant Prairie 1 & 2, Pulliam 5 to 8, Weston 1 to 3 and South Oak Creek 5 to 8. The analysis excludes the new, highly-efficient Elm Road 1 and 2 (brought online in 2010 and 2011) and Weston 4 (2008) coal-fired EGUs that are anticipated to increase in utilization under any application of building blocks. The analysis also excludes EGUs that will be retired prior to 2020 to analyze the impact to capacity that is anticipated to actually be operating in Wisconsin.

The 5% fleet-wide degradation described above more than offsets any efficiency improvement reasonably expected to occur under building block 1. Therefore, EPA needs to adjust its building block 1 methodology to account for full interaction of the building blocks in setting BSER, such as allowing a bottom-up approach as previously described, or otherwise ensuring any presumptive HRI percentage is calculated based on the offsetting nature of building blocks 2 and 3b.

8. When developing building block 1, EPA should exclude certain coal-fired EGUs and treat EGUs converted to cleaner fuels as coal-fired EGUs.

A. <u>EPA should not apply building block 1 to coal-fired EGUs that will be retired 2020.</u>

EPA did not consider the remaining lifetime of units, as required by the CAA, when proposing building block 1. In doing so, building block 1 should not apply to any coal-fired EGUs that will be retired prior to 2020. Excluding retiring coal-fired units from this building block acknowledges that further investment is neither prudent nor cost-effective, other than for maintaining the EGU until it is retired. This is particularly true in cases where the EGU has already been slated for retirement.
Wisconsin EGUs that will be retired between 2012 and 2020 are listed in Table 2. In addition to removing these EGUs from building block 1 calculations, the final rule should allow states to adjust goals to exclude any other EGUs retired by 2020.[5]

Table 2. Coal-fired EGUs to be retired by 2020.

EGU	Action	Date of Retirement	Enforceability
Alma 4	Retirement	October 2014	Retired
Alma 5	Retirement	October 2014	Retired
Edgewater 3	Retirement	January 2016	EPA Consent Decree
Nelson Dewey 1	Retirement	January 2016	EPA Consent Decree
Nelson Dewey 2	Retirement	January 2016	EPA Consent Decree
Pulliam 5	Retirement	June 2015	EPA Consent Decree
Pulliam 6	Retirement	June 2015	EPA Consent Decree
Weston 1	Retirement	June 2015	EPA Consent Decree
Edgewater 4*	Retirement / Convert to NG	January 2019	EPA Consent Decree

B. <u>EPA must exclude new supercritical coal-fired EGUs from building block 1.</u>

Prior to 2012, Wisconsin utilities brought online three new, supercritical coal-fired EGUs (Elm Road 1 & 2 and Weston 4). These units have implemented all of the HRI measures used by EPA in developing

[5] This comment is made in context of EPA's proposed baseline year of 2012. This does not preclude our comments that the rule should also provide credit for similar actions that reduced CO_2 emissions prior to 2012. Discussion concerning credit for early action is provided in Part 4 of our comments.

building block 1. In addition, these units have implemented the latest technologies for heat recovery and installed steam turbines designed to prevent some of the efficiency degradation that occurs in older turbines. These EGUs also have the most efficient pollution control equipment and variable speed fan drives. As there is no potential for further HRI at these EGUs, EPA must exclude these units from building block 1.

C. EPA should treat EGUs designed as coal-fired EGUs and converted to cleaner fuels as coal-fired EGUs in calculating the goal, but not apply building block 1 to them.

A number of coal-fired EGUs have already been, or will be, converted to natural gas or biomass in Wisconsin (see Table 3). Because these EGUs were originally designed and operated as coal-fired EGUs, they should continue to be treated as coal-fired EGUs in calculating the resulting emission rate goal for building block 1. However, EPA should not apply the HRI actions for coal-fired EGUs to these units. This approach would credit the voluntary action of converting the EGUs to cleaner fuels and also acknowledges that they may no longer be appropriate for the units. Some units may already have incurred losses of efficiency when switching to these fuels for which the boilers where not originally designed. This approach should be applied to both EGUs converted prior to and after the 2012 baseline (or any other finalized baseline).

Table 3. Coal-fired EGUs converted to natural gas or biomass by 2020

EGU	Action	Date of Action	Enforceability
Stoneman DTE	Convert to Biomass	January 2009	Removed of coal system / permit
Blount 1,2,7, & 8	Convert to NG	January 2011	Removed of coal system / permit
Edgewater 4*	Retirement / Convert to NG	January 2019	EPA Consent Decree
Bayfront 5	Convert to NG	April 2015	Permit
Valley 1,2,3, & 4	Convert to NG	October 2015	Removing coal system / Permit
Weston 2	Convert to NG	June 2015	EPA Consent Decree

9. Building block 1 must allow for the degradation of heat rate that occurs between reasonable maintenance cycles.

EPA developed building block 1 by assuming an amount of improvement identified in the Sargent and Lundy report for each HRI action. However, these values appear to represent the amount of improvement that may be gained in the first year the action is implemented, not over the long-term.

For example, Wisconsin utilities closely monitor and maintain steam turbine operation, because heat rates will indeed degrade over time. However, opening the turbines for maintenance is a significant endeavor requiring careful planning. Many Wisconsin utilities perform turbine maintenance every 5 to 8 years. Under this schedule, as discussed in comment 6, the heat rate of Wisconsin's vintage coal-fired EGUs has improved over time. Thus, EPA cannot assume that a more frequent turbine maintenance schedule is appropriate for Wisconsin EGUs. In fact, new turbines are designed to be opened up only after 10 years or more of operation. Therefore, when calculating building block 1, EPA must allow for reasonable maintenance cycles. The best way to do this is to hold EGUs to the heat rate that is expected at the end of the maintenance cycle. This approach should apply to other building block 1 HRI actions as well as air heater leakage, condenser cleaning, boiler feedpump rebuilding and economizer replacement.

10. EPA should rely on fuel consumption from the Clean Air Markets Division (CAMD) database in calculating net heat rates.

EPA relied on fuel consumption data from EIA Form 860 to calculate the net heat rates used in determining building block 1. However, the EIA fuel consumption data is inconsistent with the fuel consumption data reported and certified by utilities to the CAMD database for some Wisconsin EGUs The EIA fuel consumption data is also not required to be reported using the same quantification methods for all EGUs, as is required under the CAMD database. To avoid the variations and inconsistencies that could result when using the EIA fuel consumption data, EPA should instead use the CAMD database fuel consumption values, which are reported for purposes of compliance and undergo a quality assurance and certification process.

11. Building block 1 should not include HRI actions related to environmental controls.

EPA's current approach penalizes EGUs that have implemented pollution control equipment. EGUs that have implemented controls to comply with other federal regulations such as the Clean Air Interstate Rule (CAIR), the Best Available Retrofit Technology rule (BART) and the Mercury and Air Toxics Standards rule (MATS) are less efficient on a net heat rate basis (i.e., have a higher heat rate) due to the parasitic load of their environmental controls. Uncontrolled EGUs have lower heat rates and therefore would not have to improve their heat rates as much after applying the 6% HRI. Therefore, applying a 6% HRI (or other fixed HRI percentage) to all units is inequitable and penalizes those EGUs that have already installed pollution control equipment.

In addition, future federal criteria pollutant standards may require existing pollution control equipment to be operated more frequently or require additional EGUs to install controls. States should also not be penalized for complying with any future CAA regulations, which will cause their EGUs to lose efficiency on a net basis.

The best and most appropriate means of addressing these issues is to eliminate HRI actions for pollution control equipment from building block 1. Both the states and utilities must be free to respond to pollution control requirements outside of any CO_2-related requirement.

12. The rule must allow for future changes at EGUs that may affect the state's ability to achieve building block 1 goals.

As previously noted, converting EGUs to cleaner fuels, or installing pollution control equipment, will change the base heat rate for individual EGUs and therefore the achievability of building block 1. In addition, there are also other actions that will affect EGU heat rates (such as the new cooling water discharge regulations under 40 CFR part 316) which may also decrease EGU efficiency. An EGU may also switch from bituminous to subbituminous fuel to reduce SO_2 emissions. The rule must somehow account for and allow these changes which affect heat rates. At a minimum, states should be able to make these adjustments to their building block 1 goal.

13. Building block 1 must be phased in over the compliance timeframe.

EPA's presumption that building block 1 HRI actions can be accomplished by 2020 is unrealistic. Unless significant adjustments to EPA's building block 1 approach are undertaken based on the actual HRI feasibility of individual units, EGUs will be forced to implement significant improvements, many of which take years to plan and implement and generally require approval by the PSCW. A full turbine upgrade, for example, can take up to seven years to get planned, approved, and installed. Since EPA is not expected to approve state plans prior to 2019, this means that such an upgrade should not be presumed to occur prior to 2026.

Even if EPA adjusts building block 1 to align with the real technical potential for HRI in each state, EPA must consider that the most effective long-term solution in some cases may be actions (such as plant retirement or fuel switching) that are beyond BSER, but which may make more sense for utility systems in the long-term. EPA needs to allow sufficient time beyond 2019 to accommodate these potential alternatives. Finally, EGU outages for equipment installations have to be coordinated by the independent system operator (ISO). This planning and approval process, along with any necessary permitting, also cannot occur by 2020.

In recognition of these realities, Wisconsin's preferred approach is for EPA to eliminate the interim goal and allow states to determine a schedule for implementation based on feasibility and cost. However, if EPA chooses to retain the interim goals and allow states to phase in building block 1 over the entire compliance period, a phase-in schedule should consider the time required to integrate any transmission enhancements needed to address impacts to reliability, as indicated by MISO and the North American Electric Reliability Corporation (NAERC).

14. EPA must not include HRI actions that may trigger New Source Review requirements.

Triggering NSR could act as a disincentive to performing HRI actions. EPA must limit HRI actions to those that will not trigger NSR requirements. Wisconsin utilities identified air heater leakage, cooling tower packing and economizer replacement as actions that could have NSR implications. EPA should either ensure that HRI actions taken under this proposal will not trigger NSR or modify the NSR rule to avoid this possibility.

COMMENTS ON BUILDING BLOCK 2 (NATURAL GAS COMBINED CYCLE DISPATCH)

Wisconsin does not believe that the CAA contemplates shifting generation between types of EGUs in setting a BSER requirement, as EPA proposes in building block 2. Doing so is beyond the bounds set by the CAA, as BSER should reflect what is achievable and cost-effective for each specific source category. BSER also does not contemplate setting emission limits across different types of EGUs in the whole generation system. Finally, the current fleet of NGCCs was installed to replace retired coal capacity, accommodate anticipated demand growth, and support specific needs of the electrical grid. Dictating a specific capacity factor for the existing NGCC fleet negates these functions. Thus, Wisconsin believes it is inappropriate for EPA to either include building block 2 in setting BSER or apply it as proposed in this rule.

In that context, Wisconsin provides the following comments on building block 2.

15. EPA cannot assume that NGCC generation first offsets coal-fired generation. EPA also must not allow offsetting generation to degrade coal-fired generation efficiency.

EPA cannot assume that NGCC generation will offset coal-fired generation, as this is not how the electric supply grid functions in reality. Instead, EPA must assume that additional NGCC generation will offset a combination of coal-fired generation, renewable energy, and simple cycle combustion turbine operation. EPA should use modeling to determine how NGCC generation offsets other generation throughout the electric supply system. This modeling will likely show that increasing NGCC generation will offset existing and new renewable energy, indicating that the proposed RE requirement is neither practical nor cost-effective in operating the grid. This is part of the overall modeling analysis of the interaction of the building blocks discussed in comment 3. At a minimum, EPA should assume that additional NGCC generation will offset renewable energy capacity before existing coal-fired generation and solid fuel biomass-fired generation.

In performing the evaluation or modeling as described, EPA must also establish a floor for operation of existing coal-fired EGUs that prevents degradation of their heat rates. Comment 7 describes how the real heat rate begins to degrade significantly when the capacity factor for Wisconsin EGUs falls below 50%. Therefore, EPA should not allow the capacity factor of Wisconsin coal-fired EGUs to fall below 50% when determining building block 2. In applying this criterion, EPA must also maintain operation of all of the coal-fired EGUs.[6] Significant investments have recently been made in these EGUs to continue their efficient operation into the foreseeable future.

16. EPA has not demonstrated that a fleet-wide NGCC 70% capacity factor is either achievable or consistent with BSER.

In setting this building block, EPA must apply a capacity factor that has been demonstrated as both achievable and economical in order to meet the CAA criteria for BSER. EPA's analysis does not meet this test for a number of reasons.

EPA inaccurately assumes that because 10% of the nation's NGCC units operated at greater than 70% capacity in 2012 that the rest of the NGCC fleet can be dispatched at this same level every year. This conclusion is unproven. EPA's data actually shows that NGCC units nationally, on average, operated at a 45.8% capacity factor in 2012. Given that natural gas prices were at historical lows and the summer load demands at all-time highs that year, it is more valid to say that 2012 does not represent a NGCC capacity factor that can be achieved on a long-term basis. Instead, EPA can only conclude that NGCCs operated at a 45.8% capacity factor during a single year that experienced an unusually high level of NGCC operation due to unique circumstances.

EPA also did not consider existing permit, physical, and environmental constraints that may restrict real operating levels for individual NGCCs. Some of these restrictions may include limitations on operating hours, fuel use or limits on water usage. In some cases, removing these restrictions may trigger NSR review. As previously mentioned, this rule should not contemplate actions that may trigger NSR.

As previously noted, EPA did not evaluate the use of NGCCs in context of applying all building blocks. In this context, EPA has not proven that electric reliability will be maintained and that there is sufficient natural gas infrastructure and supply.

In performing the IPM cost analysis, EPA also did not cost the proposed rule with NGCC's operating at 70% capacity factor. The CAA requires that BSER be set considering achievable and cost-effective control options. Without accurately determining costs, EPA has not met this test.

Finally, building block 2 relies on the action of many entities and variables outside the control of the affected utilities. This reliance significantly expands the traditional approach taken in setting emission limitations where the evaluated actions are limited to actions that can be taken at the source. Therefore, in applying a system-wide approach, EPA must prove that these outside factors will not limit the capacity factor applied in building block 2 for the vast majority of NGCCs in the country. That is, the limit must either be set specifically for each state, or be set nationally based on the achievable capacity factor for the most constrained state.

[6] See Part 3: Technical Corrections, comment 3.C.

17. At a minimum, EPA should set a NGCC capacity factor for building block 2 on a state-by-state basis using a three-year average.

EPA should develop building block 2 based on the NGCC capacity factor that has already been achieved by the NGCCs in each state. For example, a more supportable approach would be to use the historic average of the three years of highest NGCC capacity factors for each state. Using this average more fully accounts for variable conditions in fuel supply, pricing, NGCC maintenance cycles and interaction with other generation types that were not considered by EPA in setting the 70% capacity factor.

EPA should then test the viability of the resulting three-year average capacity factor by considering the worst-case conditions that may occur in each state. These conditions, should, at a minimum, account for peak natural gas use by all sectors (residential, commercial, vehicle, etc.), natural gas transmission and storage constraints, and peak electric reliability needs. Any capacity factor must also be evaluated for offsetting interactions with other building blocks. This approach would ensure each state-specific capacity factor could support system demand over the long-term, including periods of extreme demand (e.g., polar vortex events).

While the capacity factors should be established on a state-by-state basis, if EPA maintains the approach of applying a single capacity factor to all NGCCs on a national basis, then this capacity factor should be based on what is achievable in the most constrained state (i.e., the state with the lowest historic 3-year average capacity factor). This is because the limit set under BSER must be achievable across all states and sources so that no state can be put at a disadvantage by the regulation.

18. Historically, 2012 was an outlier year for NGCC EGU operations.

The capacity factors of NGCC EGUs in 2012 should be considered the maximum achievable NGCC utilization for each state. In 2012, the electrical grid experienced both extreme summer peaking conditions and record low natural gas prices. These conditions were optimal for NGCC use and resulted in historically high use of NGCCs system-wide. Accordingly, EPA cannot assume that NGCC capacity factors could easily exceed those experienced in 2012.

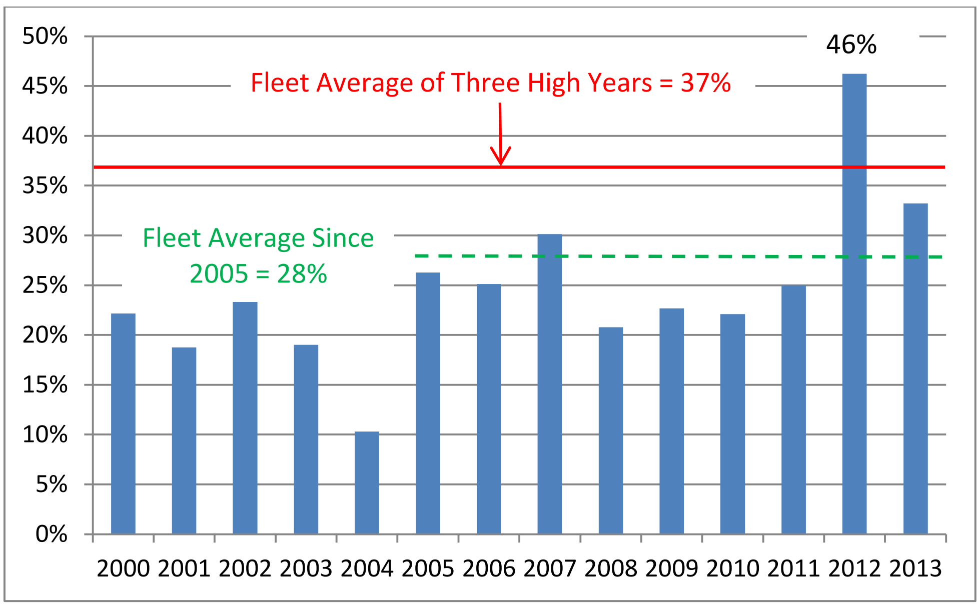
2012 was followed by extreme winter weather conditions in 2013, during which natural gas prices increased and Wisconsin industrial customers were called on to curtail natural gas usage. Because of this series of events, natural gas supply reserves heading into the 2014-15 winter are still below 2008 levels, even with increased production of natural gas. This creates further challenges to increasing NGCC use as EPA has proposed. This evidence strongly supports that EPA should use a three-year historical average, or even exclude 2012 in calculating a three-year average, to determine any capacity factor for building block 2.

19. Wisconsin's capacity factor for building block 2 should be no greater than 37 percent.

Applying the method discussed in comment 17, and when considering all years starting in 2005, the three-year average of the highest annual capacity factors for the Wisconsin NGCC fleet is 37% (see Figure 2). EPA should therefore assume, when developing building block 2 goals, that this is the maximum capacity factor available to Wisconsin.

Figure 2 also confirms that 2012 was an outlier for NGCC operation in Wisconsin. The state's capacity factor in 2012 (46%) is approximately 70% higher than the average capacity factor for the entire NGCC fleet from 2005 through 2013 (28%). This supports the contention that 2012 was an unusual year and must not be used as the sole year in determining achievable NGCC capacity factors for each state. Note that, if 2012 is treated as an outlier and removed from the analysis, the three-year average capacity factor would be just 29%.

Figure 2. Annual Utilization (Capacity Factor) of Wisconsin NGCCs Since 2000.



20. A building block 2 capacity factor of 70% negates any HRI achieved by building block 1.

The goal of the building block 2 is to reduce the operation of the coal-fired EGUs and reduce CO_2 emissions. However, as discussed in comment 7, our analysis shows that the efficiency of the Wisconsin coal-fired EGU fleet could fall as much as 5% due to heat rate increases brought on as a result of applying building block 2 as proposed by EPA. In that assessment, our preliminary estimates show that the achievable HRI for vintage Wisconsin coal-fired EGUs is estimated to range between 0.5% and 2.3%. Therefore, any CO_2 reductions achieved by building block 1 are more than offset by the inefficiencies caused by building block 2; specifically, the result is a net loss of over 3% efficiency for Wisconsin's coal-fired fleet. This result is contrary to the intent of BSER and further supports the conclusion that Wisconsin's maximum NGCC capacity factor should not exceed 37%.

21. EPA did not adequately assess the electric reliability impacts resulting from a significant increase in reliance on NGCC units.

By increasing NGCC units to a 70% capacity factor, EPA is proposing that these units will operate as baseload EGU plants. However, the agency failed to fully evaluate the impact of this decision on electric reliability or reserve capacity needs. In order to do so, EPA must consider several factors.

First, EPA must consider that NGCC capacity is currently operated in an intermittent and load-following fashion to meet changing electricity demand. Operating NGCC units at a high capacity factor leaves less open capacity that can be used to react quickly to demand swings and peak loads. Since other reliable generation, such as coal-fired EGUs, cannot ramp up as quickly as NGCC units, load following must be accomplished with new NGCC capacity or simple cycle combustion turbines (CTs). EPA must account for this added (or switch in) capacity. In addition, EPA must remember that it is not the average annual load demand peaks and swings that must be allotted for; it is the maximum capacity that may be needed in any one hour to maintain electric reliability. EPA has not provided a full assessment that considers these factors and must do so prior to finalizing the rule.

Second, EPA must consider the need for added load-following capacity due to the installation of additional renewable energy under building block 3b. EPA also must consider that some NGCC capacity has been built to meet specific load profiles and must remain available for this purpose. For example, Wisconsin's Port Washington NGCC facility was built to replace coal-capacity and meet large, sudden demand changes caused by electric arc metal furnaces in the area. It is important facts and nuances about the EGU fleet, such as this one, that EPA's proposal fails to recognize and calls into question the thoroughness and basis of EPA's rule.

EPA also did not adequately account for potential losses of current generation sources. This includes the retirement of nuclear generation. Currently, significant nuclear generation will be retired in 2030 and 2033 in Wisconsin. EPA must also account for the loss of hydroelectric generation during prolonged droughts or due to the elimination of dams for ecological reasons.

Finally, EPA did not model the proposed rule in its entirety with NGCCs operating at a 70% capacity factor. In fact, the IPM runs conducted by EPA only indicated 50% utilization of NGCC capacity (including new units). In performing this analysis, EPA assumed that electricity could flow unconstrained within the major generation regions. Therefore, EPA did not conduct modeling that adequately assesses electric reliability impacts.

In summary, capacity types cannot be interchanged without consequences to the electric grid. EPA has not demonstrated that operating all combined cycle generation at 70% capacity factor, and leaving other fuel types to respond to intermittent and peak demand, will not severely and adversely affect electric reliability. EPA must perform this evaluation, in light of the abovementioned factors and in context of the generation system operating as a whole, and make the needed adjustments to the proposal prior to finalizing its rule.

22. EPA must fully assess natural gas infrastructure and availability in each state.

Electric generation from natural gas is dependent upon a reliable supply of natural gas. EPA must base BSER on currently proven supply levels and existing infrastructure; at the most, EPA can only consider additional infrastructure that is currently planned to be in place prior to 2020. Basing the assessment on what is currently demonstrated and achievable is also consistent with the CAA criteria for setting BSER. In this context, EPA should address the following issues in evaluating the adequacy of the natural gas system.

A. <u>EPA did not adequately assess natural gas pipeline capacity and storage.</u>

Natural gas storage capacity became overextended in Wisconsin in 2012 and 2013, with resulting price increases and supply shortages. Dispatch of NGCC to a 70% capacity factor is estimated to increase Wisconsin's natural gas consumption by 12.6%. EPA has not shown that the supply and storage infrastructure for natural gas would be available to support such an increase in consumption; in fact, there is much evidence that EPA's assumptions on this topic are incomplete and, in part, erroneous.

First, prior to the release of EPA's proposal, the Midwest Independent System Operator (MISO) identified constraints that need to be addressed in order to maintain natural gas supply for electric generation in the region; these constraints do not appear to have been considered by EPA.[7] In its own analysis, EPA projects only a 4 to 8% increase in pipeline capacity serving Wisconsin in the foreseeable future; this is clearly at odds with the 12.4% anticipated demand increase. In addition, in assessing pipeline capacity, EPA did not consider that the existing infrastructure supporting simple cycle turbines and new NGCC units will have to be upgraded in order to replace the load and peaking capacity of the existing NGCC capacity.

Second, storage capacity for natural gas has remained relatively flat. There are some additions to storage capacity coming online, but these are relatively small in the context of total system capacity and also are located far from Wisconsin. Adding storage capacity is a costly endeavor which is dependent on geological formations and access; it cannot simply be added as needed. In addition, Wisconsin has no potential natural gas storage capacity because the appropriate geology does not exist in the state. EPA does not consider these factors in its proposal.

Finally, there are fuel availability factors that are not directly related to physical infrastructure, but will be driven by a market for fixed-load support. EPA must consider that utilities may have to procure long-term contracts for storage capacity in order to ensure a reliable fuel supply. At this time, it is unclear how these factors will affect electric reliability; however, there certainly will be a cost impact. One Wisconsin utility currently in the planning stages for a new NGCC has relayed that reliable transportation, storage and no-notice service could cost $12 million per year for a 500 MW plant. In

[7] November 2013, *MISO Summary Document – Phase III Gas Infrastructure Analysis*, Midwest Independent System Operator.

addition, a new or upgraded connection would cost approximately $2-3 million dollars and the lateral feed $2.5 million per mile.

B. EPA must account for natural gas needed by other sectors, including residential heating, and should not apply building block 2 during the heating season.

EPA cannot assume that electric generation is the most valuable use of natural gas. Already, many industrial and utility facilities are replacing coal boilers with natural gas boilers in response to the boiler MACT rule. In addition, natural gas is increasingly being used for transportation. EPA must also consider that the use of DSM as a compliance method will include converting electricity end-use to natural gas. In its assessment, EPA must account for the increasing natural gas demand from all of these sectors.

Regardless of the growth in other sectors, EPA must also ensure the availability of natural gas for residential heating purposes. This has far-reaching impacts on individual Wisconsin residents. As previously stated, implementing building block 2 will increase Wisconsin natural gas demand by 12.6%. As a state heavily dependent on natural gas for heating, we do not believe that building block 2 should be applied (in full or in part) during the winter heating season. This approach safeguards home heating supplies by maximizing use of coal-fired power plants, as was needed during the bitterly cold winter of 2013-14.

23. Building block 2 must be phased in over the compliance timeframe.

EPA's presumption that building block 2 can be implemented by 2020 is unrealistic. Without further evaluating the implications on reliability, it must be assumed that additional natural gas capacity will be needed to comply with the rule. The need for new natural gas generation can be estimated by looking at the difference between the maximum three-year annual average capacity factor of 37% (as discussed in comment 19) and the fleet average since 2005 of 28%. This is equivalent to approximately 260 MW of capacity. Assuming that this capacity was used to fill rapid and short-term load needs, new NGCC or simple cycle combustion turbine (CT) capacity will have to be built as replacement capacity; this is equivalent to approximately 13 new 100 MW CTs operating at 20% capacity factor. Building any new CT or NGCC capacity will require at least five to seven years. It is clearly impossible for this capacity to be operational by 2020, given that it is very unlikely the state will have an approvable plan prior to 2019. Finally, EGU outages for equipment installations have to be coordinated by the independent system operator (ISO). This planning and approval process, along with any necessary permitting, also cannot occur by 2020.

In recognition of these realities, Wisconsin's preferred approach is for EPA to eliminate the interim goal and allow states to determine a schedule for implementation based on feasibility and cost. However, if EPA chooses to retain the interim goals and allow states to phase in building block 2 over the entire compliance period, a phase-in schedule should consider any additional necessary infrastructure improvements needed to eliminate existing natural gas supply constraints and ensure a reliable fuel supply. In addition, EPA also should consider the time required to integrate any transmission enhancements needed to address impacts to reliability, as indicated by MISO and NAERC.

24. EPA should not regulate simple cycle combustion turbines (CTs) under the proposed rule.

Currently, the proposed rule will apply to CTs that operate over one-third of capacity. This, in essence, limits the use of the CTs. EPA has already determined that switching load to NGCC units is acceptable. Therefore, it is illogical to restrict the switching of load to CTs, especially when this capacity will be needed to ensure electric reliability. The most likely outcome of EPA's proposal is the installation of additional CT units, which would avoid the arbitrary restriction. Instead, EPA should simply not regulate CTs in this proposal.

25. Additional methodological changes EPA should make when calculating building block 2.

Wisconsin recommends that EPA consider the following changes to its methodology in calculating building block 2.

A. <u>Nameplate Capacity</u>

The nameplate capacity used by EPA will not accurately assess the current operating levels of NGCC units or the number of new EGUs that must be built to meet shifting loads and maintain electric reliability. EPA should use actual values for assessing operating levels and the impacts of building block 2, particularly when evaluating electric reliability issues.

B. <u>Duct-firing</u>

NGCCs are equipped with duct-firing to achieve the necessary heat input for high capacity utilization. Typically, NGCCs are not operated at these higher levels because the duct-firing is less efficient than normal operation and it increases NOx emissions. This is particularly important in meeting NOx emission limitations in non-attainment areas. Therefore, some potential ways that may help address this issue are either restricting the use of NGCC capacity below levels triggering duct-firing or accounting for these impacts by setting less stringent targets. EPA could also consider simply excluding NGCC units located in non-attainment areas or, alternately, assuming additional costs for installing NOx control equipment.

26. EPA should not apply building block 2 further.

EPA requested comment on whether any switch to natural gas generation should be expanded beyond the use of NGCC to include fuel switching from coal to natural gas fuels directly at the steam boilers. This action is beyond the EPA's authority under the CAA, as BSER should not dictate the use of fuels or the capacity factor of an EGU in any manner.

COMMENTS ON BUILDING BLOCK 3a (NUCLEAR POWER)

EPA's approach to this building block must recognize the unique and challenging nature of nuclear power in this country. Licensing for these units is lengthy and strict, and nuclear power plants must retire upon expiration of their licenses. States and utilities do not have the ability to control whether these plants remain operational or retire. In addition, many states (including Wisconsin) have laws that create a de facto prohibition on the construction of new nuclear power plants; therefore, replacing retiring nuclear generation in kind is not an option. Finally, decisions about nuclear generation are complicated by extremely controversial waste storage issues.

27. EPA's decision to count 5.8% of nuclear generation in each state as "at risk" and including it in that state's goal is arbitrary and inappropriate.

Using 5.8% as the level of "at risk" nuclear was derived based on national data. While this percentage may be meaningful at the national level, it has no relevance at an individual state level. Wisconsin currently only has one nuclear power plant that has two reactors, and if this plant were to shut down, it would do so unit-by-unit, meaning that 100%, 50% or 0% of its generation is at risk. It would actually be impossible for the plant to lose 5.8% of its capacity. Accordingly, requiring the state to preserve that 5.8% of "at risk" generation is arbitrary.

Furthermore, generation from Wisconsin's Point Beach Nuclear Plant should not be considered "at risk" at all until its licenses expire, at which point EPA should recalculate the state's goal as discussed below. This facility has long-term power purchase agreements for its power and it is in a rate-regulated state, meaning that its generation should be considered secure until its scheduled retirement. In addition, its owner (NextEra Energy) recently invested in an extended power uprate to increase the capacity of the plant supported by a long-term power purchase agreement with WPPI Energy (as discussed in our attachment on pre-proposal actions[8]), making it even less likely that this plant will close prematurely. Accordingly, Wisconsin does not have any "at risk" nuclear generation and should not have a goal for this part of building block 3.

28. The federal government must develop an environmentally sound, long-term solution to nuclear waste disposal.

A number of states, including Wisconsin, have bans on construction of new nuclear power plants. These bans are likely to remain in place until a long-term solution to the waste storage issue is developed. Without a long-term solution to this issue, a potential source of zero-carbon, baseload electricity is effectively eliminated from the list of compliance options for states. Any solution to the waste disposal issue will require action at the federal level, and the state of Wisconsin encourages EPA to prioritize working with other federal agencies to develop long-term disposal options promptly.

[8] Part 4: Wisconsin's Pre-Proposal Actions to Reduce CO_2 Emissions from the Power Sector.

29. EPA should recalculate state goals when nuclear power plants reach the end of their planned lifetime.

If states choose to comply via a mass-based standard, retirement of a nuclear power plant at the end of its license could be extremely problematic for the state, which would be required to replace this carbon-free baseload power source at that time. The licenses for the units at Wisconsin's remaining nuclear plant, Point Beach, are set to expire in 2030 and 2033. These units provided 16% of the state's generation in 2012, and it would be challenging to replace this baseload carbon-free generation with other types of carbon-free generation (e.g., renewables), meaning that the state's total CO_2 emissions would likely increase significantly as fossil units replace at least part of this generation. Accordingly, EPA should recalculate state goals when nuclear power plants reach the end of their planned lifetime, excluding this building block from the new calculation and allowing some portion of fossil generation to replace the retiring nuclear.

30. EPA should allow states to credit nuclear plants whose licenses are extended beyond 60 years or that operate at a greater than assumed capacity.

Such an extension of a nuclear power plant's lifetime would avoid the increase in CO_2 emissions from fossil fuel-fired units used to replace the retired nuclear generation discussed above and should count as a credit towards a state's goal. Similarly, if the nuclear plant can increase its generation, this additional generation would offset baseload fossil generation and should count as a credit towards compliance. This approach is consistent with the approach for retiring nuclear plants discussed above.

COMMENTS ON BUILDING BLOCK 3b (RENEWABLE ENERGY)

In general, EPA's proposed approach to calculating building block 3b requires states that have already made significant investments in renewable energy (RE) to expand renewables more than states that have been slower to act. Wisconsin's comments focus on three primary aspects to the RE goal calculation: setting the target, use of the growth rate, and handling of interstate purchases of RE. The comments also address a number of compliance issues related to renewable energy in the Compliance Issues section of our General Comments.[9] See also separate comments submitted into the docket from the Wisconsin DNR on the regional technical potential approach for RE goal as presented in EPA's October 30, 2014 Notice of Data Availability.

31. The use of state renewable portfolio standard (RPS) targets to determine goals is inappropriate.

Renewable portfolio standards are set largely based on policy goals rather than technical potential, and most states meet these goals partly through purchase of RE from other states, rather than just from in-state generation. Accordingly, states with high RPS goals are states that have chosen to invest in renewable energy (and reduce CO_2 emissions) and not necessarily those states that have naturally high

[9] Part 1: General Comments.

capacity for renewables development. EPA should not set higher goals for states that have already made a policy decision to invest in RE than for states that have not done so.

Additionally, most states’ RPS goals assume the use of considerable existing hydroelectric generation. Thus, EPA’s exclusion of this generation from compliance is inconsistent with state RPS goals and with the way EPA set the renewables part of the goal.

Setting state goals based on regional targets presents a number of problems as well. Renewable energy potential varies significantly within the regions EPA used. For example, Wisconsin has significantly less wind potential than does South Dakota, but both states are in the same region used by EPA to set the building block 3b goals. There is little logic in grouping such different states together in such an arbitrary manner. Grouping states together regionally in setting an RPS-based goal may further enhance differences among states and additionally “penalize” early adopting states that have high RPS goals. States in regions that have taken early action via aggressive RPS standards will be required to achieve more in the future than they would have if they were in a region with less ambitious goals. Such groupings create artificial differences among the goals for the different states depending on the renewable policy decisions made by other states in their region.

32. The use of a state’s technical and economic potential to set RE goals ignores the interstate nature of renewable energy.

The use of a state’s technical and economic potential (as discussed in EPA’s alternative approach technical support document) avoids setting the goal based on renewable energy policies. However, this potential-based approach ignores the interstate nature of renewable electricity and the fact that utilities and other entities frequently purchase RE from other states with higher RE potential. This leads to serious inequity issues and also may fail to acknowledge existing investments in out-of-state RE.

A potential-based approach requires enormous amounts of investment from states that have large technical and economic potentials (such as the Plains states). At a minimum, the EPA should cap the amount expected of such high-potential states. For example, EPA’s alternative approach would require South Dakota to generate RE that is equivalent to more than double its 2012 total generation, corresponding to adding 16,000 GWh of RE and generating 6 to 7 times as much wind generation in 2030 as in 2012. This would require a large amount of capital investment by the state, with utilities in other states being unlikely to support this development if they will not be credited with the RE for compliance. This approach would also result in the state generating more RE than it can consume. This RE would therefore be exported to other states, such as Wisconsin, who would end up paying for the RE but not being credited with this renewable generation. This approach is unfair to both the generating and purchasing states.

In contrast, the alternative approach would require very little of states that have low RE potentials, despite the fact that such states could invest in RE development in other states with higher potential. For example, under this approach, Kentucky is only required to add 2,000 GWh of RE (projected as hydro, which doubles the state's hydro generation), despite the fact that Kentucky could buy wind power from neighboring Illinois, which has much higher technical potential. Similarly, because of the methodology by which solar generation potential is calculated, Florida is only expected to generate RE equivalent to 1% of its 2012 generation by 2030, despite having large solar energy resources available.

Wisconsin is also concerned that because the alternative technical and economic potential approach is based on potential within a state, EPA may only permit in-state RE generation to count for compliance under this approach. Wisconsin would oppose this approach because it would not credit the state for the large amount of investment Wisconsin utilities, citizens and others have made in RE in neighboring states. (See comment 34 below for more information on the state's RE investments in neighboring states.) It is essential that Wisconsin be able to use this out-of-state RE for compliance.

33. EPA should apply a growth rate that does not set higher goals for states that have already built or invested in significant RE relative to those that have not.

EPA's use of a growth rate that is a certain percentage of existing RE generation creates significant inequities among states by requiring more growth from states with more existing RE. If EPA continues to rely on a growth rate for RE, they should apply a type of growth rate that does not depend on a state's starting point (such as a linear growth rate applied equitably to all states). EPA should also consider the practical limitations on growth of RE, such as the requirements to integrate new RE into transmission/distribution systems, the difficulty of obtaining regulatory approval for new RE, and the time required to build new RE generation sources.

34. EPA needs to establish clear guidelines to allow states that own renewable generation in another state or purchase such generation to claim credit for that RE.

EPA must assign credit for RE sold across state lines to the state that purchased that generation in order to be consistent with how RE is treated within established tracking systems. Generation and sale of RE is already tracked in well-established tracking systems, in which the renewable attributes of the RE follow purchase of the renewable energy certificate (REC), which represents a megawatt-hour (MWh) of generation.[10] The renewable attributes (including emissions reductions) in these systems are associated with the amount of <u>generation</u> (MWh), and when credits are sold across state lines, the renewable attributes follow the credit,[11] regardless of where the RE was generated and regardless of whether the generating state had incentives (such as production tax credits) to promote in-state generation. EPA

[10] From the Midwest Renewable Energy Tracking System (M-RETS) Operating Procedures (April 23, 2010; emphasis added): "An M-RETS Certificate represents all of the attributes from one MWh of electricity generation from a renewable generating unit… M-RETS expects that its certificates be "whole certificates"… A "Whole Certificate" is one where none of the renewable attributes have been separately sold, given, or otherwise transferred to another party by a deliberate act of the Certificate owner. Renewable attributes shall include the environmental attributes that are defined as any and all credits, benefits, <u>emissions reductions</u>, offsets, and allowances, howsoever entitled, directly attributable to the generation from the generation unit(s).

[11] An exception to this approach is the North Carolina Renewable Energy Tracking System, which does not require that environmental attributes be automatically bundled with RECs.

must treat cross-state sales of RE in a parallel way, allowing the purchasing state the credit for that RE. This means that in cases where one state has an RPS and purchases RE from another state that has a production tax credit, EPA must consider the purchasing state to have the “enforceable measure” and give that state the credit for the RE. Doing otherwise would directly conflict with how RE has been treated for years under existing tracking systems.

In addition, states require clear guidance from EPA on this issue at the time of rule finalization. It has become clear during our discussions with other states that it will be difficult, if not impossible, for some states to come to agreement on how to credit RE generated in one state, but paid for by another. As previously stated, EPA must clarify that the state paying for the RE generation may claim credit for that generation regardless of where the generation physically occurs. Allowing the state in which the generation is located to claim the credit would be unfair to entities who have made investments in out-of-state renewable generation to optimize use of renewable resources, in addition to being inconsistent with how tracking systems treat RE, as discussed above.

For example, Wisconsin utilities built, own and operate 378 MW of wind energy in neighboring Minnesota and Iowa that is dedicated to meeting Wisconsin’s renewable energy needs (see Table 4). This is in addition to wind farms owned by utilities within their service territory in other states, some of whose generation may be used for compliance in Wisconsin. In 2012, these facilities generated over 970,000 MWh of carbon-free electricity, or about 35% of the total out-of-state wind energy claimed by Wisconsin under the state RPS and green purchasing agreements. Because this generation capacity is owned and operated by Wisconsin utilities for use in Wisconsin, it would be inequitable for the hosting state to claim credit for the generation. It is essential that Wisconsin be able to claim this Wisconsin owned-and-operated generation for compliance. In addition to this generation owned by utilities in Wisconsin, the utilities and others in the state purchased an additional 1,794,664 MWh of renewable electricity from our neighboring states, much of it through long-term power purchase agreements that enabled the construction and operation of these wind farms. The state must also be credited with this RE.

Table 4. Out-of-state wind energy owned or purchased by Wisconsin entities.

Out-of-State Wind Facilities Owned by Wisconsin Utilities Dedicated to Use in Wisconsin*					
Facility	Year online	State	Owner/Operator	Capacity	2012 Generation
Bent Tree Wind Farm	2011	MN	Wisconsin Power and Light Company	201 MW	430,668 MWh
Crane Creek Wind Farm	2009	IA	Wisconsin Public Service Corporation	99 MW	315,656 MWh
Top of Iowa III Wind Farm	2008	IA	Madison Gas & Electric	30 MW	74,133 MWh
Grand Meadow Wind Farm	2008	MN	Northern States Power	16 MW for WI**	49,683 MWh for WI**
Nobles Wind Farm	2010	MN	Northern States Power	32 MW for WI**	103,281 MWh for WI**
Total				**378 MW**	**973,421 MWh**

Total Out-of-State Wind Energy used by Wisconsin Under state RPS or via Green Power Purchasing agreements	
2012 total wind energy (35% owned and operated by WI utilities)	2,768,085 MWh

*Note that other Wisconsin utilities own wind farms in other states within their service territory (e.g., IA and MN) that may or may not provide renewable energy to Wisconsin.
**These numbers reflect the 16% of the power generated at Northern States Power's two wind farms that is dedicated to serving Wisconsin. The total capacity of the Grand Meadow Wind Farm is 100.5 MW, and its total 2012 generation was 310,521 MWh. The total capacity of the Nobles Wind Farm is 201 MW, and its 2012 total generation was 645,508 MWh.

EPA should also allow the use of RE purchased from other countries for compliance with the regulation provided this RE meets all of the other requirements on RE used for compliance with this rule. Wisconsin utilities currently purchase 75 MW of wind power from Manitoba via long-term power purchase agreements, and these utilities have committed to purchasing around a thousand additional MWs of wind and hydroelectric energy in future years. This RE should count towards compliance with the regulation. In addition, there is large potential for expansion of wind and hydropower capacity in Canada, particularly in Manitoba, that provides additional RE resources to nearby U.S. states. If EPA does not allow this cross-border RE to count towards compliance, these carbon-free resources may go undeveloped.

COMMENTS ON BUILDING BLOCK 4 (ENERGY EFFICIENCY)

Wisconsin has a well-established and effective statewide energy efficiency program called Focus on Energy. However, WDNR and PSCW do not have independent authority to expand this program to comply with the Clean Power Plan and are even prohibited by statute from requiring utilities to implement EE measures beyond those required under the Focus on Energy program. Because spending on this program is set by state legislation, legislative action would be necessary to increase program spending.

In addition to the issue discussed below, we also address a number of compliance issues related to energy efficiency (EE) in the Compliance Issues section of our General Comments[12] and two corrections to Wisconsin's energy efficiency goal calculation in our Technical Corrections attachment.[13]

35. EPA should adjust the way it calculates EE goals to make these goals more equitable among states.

EPA's methodology for this building block suffers from the same flaw that some other building blocks do: it requires more action from states that already have strong EE programs than from states that have done less. EPA should relax the pace at which early acting states are assumed to increase EE programs to make the goals more equitable among states. This approach would recognize that future EE savings may be more costly for those states that have already implemented significant EE measures because they have already taken advantage of the "low hanging fruit."

36. States should be able to adjust their EE goals over time.

It is impossible to predict what levels of EE savings will be achievable on a sustained basis over decades. EPA reports in the GHG Abatement Measures TSD that only three states achieved incremental savings of 1.5% or higher in 2012. Only one of these programs (in Vermont) had been operational for more than a few years at this point, so, with the possible exception of one state (Vermont), states have no experience with sustaining incremental EE savings of 1.5% over many years.

Wisconsin has one of the longest-established state-wide EE programs, which has been running for 13 years and has incentivized many different EE measures over this time period. At some point, states may reach a point of diminishing returns where achieving additional energy savings becomes cost-prohibitive. Early-adopting states like Wisconsin are likely to reach this point sooner than late-acting states. If the state discovers that it is reaching that point and can demonstrate this to EPA, EPA should allow the state to adjust our EE goal to be less stringent. Having the ability to make this kind of correction would recognize the savings already achieved by leading states and make the EE goals more equitable among states.

[12] Part 1: General Comments.
[13] Part 3: Technical Corrections.

WISCONSIN'S COMMENTS ON EPA'S PROPOSED CLEAN POWER PLAN
PART 3:
TECHNICAL CORRECTIONS

Wisconsin discovered numerous errors in the data EPA used to determine the state's interim and final goals. Corrections to the data were identified and changes were suggested in methodology necessary in developing the building blocks and cost estimates for the proposed rule. EPA should correct its data, recalculate the state goals and adjust its analysis as necessary.

CORRECTIONS TO EPA'S BASELINE INFORMATION

1. EPA must adjust Wisconsin's baseline to account for the May 2013 closure of Kewaunee Nuclear Plant

A. Background

Kewaunee Nuclear Plant closed in May of 2013. The loss of Kewaunee's generation (it provided 7.3% or 4.5 million MWh of Wisconsin's electricity generation in 2012) resulted in other generators (mostly fossil) filling the void. Any historical baseline that EPA could choose based on currently available data would include generation from Kewaunee and thus would not truly represent Wisconsin's power sector going forward. Because of the loss of this carbon-free generation source, it will be impossible for the state to attain the emissions levels achieved in 2012 without dramatic actions. Accordingly, EPA must adjust Wisconsin's 2012 baseline to account for the loss of generation from Kewaunee. EPA has already adjusted Wisconsin's nuclear goal in building block 3 by eliminating Kewaunee's generation from the 2012 baseline for purposes of that building block. Wisconsin requests that the EPA treat the closure of Kewaunee consistently in each building block of the rule by adjusting the 2012 baseline to exclude the generation previously attained from that unit.

Four different ways were investigated by which EPA could adjust Wisconsin's baseline and goals to account for the retirement of Kewaunee. These approaches include:

1. Assuming the generation would be replaced by coal;
2. Assuming the generation would be replaced by a combination of coal and natural gas;
3. Assuming the generation would be replaced by a combination of coal, natural gas and renewables; and
4. Using a 12-month baseline from July 2013 to June 2014 to represent how the power sector actually functioned after Kewaunee closed.

Electricity sales remained flat from 2010-2013, but overall fossil generation in Wisconsin increased significantly from 2012 to 2013, and all of this increase can be correlated with replacement of Kewaunee's power, as shown in Table 1. Because sales were similar in 2011 and 2013, we compared fossil generation in 2013 (when Kewaunee operated on a much smaller scale as it was shutting down) with that in 2011 (when it was fully operational) to determine the proportion in which NGCC and coal units ramped up during this time. (2012 was excluded because gas prices were so low that year.) We used the amount by which in-state renewable generation expanded from 2012 to 2013 (2012 was used in this case because RE generation would not be directly affected by natural gas prices). The combination of expanded fossil generation and additional renewables accounts for 99% of the needed expansion.

Table 1. Data for Wisconsin Generation. Data on generation at Kewaunee is from EIA, data on fossil generation is from EPA's Clean Air Markets Division (CAMD), and data on renewables comes from Wisconsin's Renewable Portfolio Standard Compliance Reports.[1]

Parameter	Generation	Notes
2012 Generation from Kewaunee	4,515,892 MWh	
2013 Generation from Kewaunee	1,733,479 MWh	
Amount of additional 2013 generation needed	2,782,413 MWh	
2013 – Additional fossil generation (versus 2011)	2,544,114 MWh	
Coal	686,523 MWh	91% of needed generation
NGCC	1,808,585 MWh	
other	49,005 MWh	
2013 – Additional renewable generation (vs 2012)	226,911 MWh	8% of needed generation

B. <u>Adjustments to EPA's Emission Rates for Wisconsin</u>

Four scenarios were tested to adjust EPA's rate-based goals for the state for the loss of Kewaunee's carbon-free generation. These scenarios are outlined in Table 2 and described below, and the results are shown in Table 3. All provide similar results.

Table 2. Changes in generation (MWh) under the different scenarios to account for lost generation at Kewaunee Nuclear Plant.

	Scenario 1	Scenario 2	Scenario 3
Additional coal	4,515,892	1,242,537	1,138,930
Additional NGCC		3,273,355	3,000,411
Additional RE			376,551
	Scenario 4		
Change in NGCC from 2012	-3,409,352		
Change in coal from 2012	7,450,031		
Change in oil/gas steam from 2012	-28,476		

[1] Renewables data includes all in-state generation, including hydropower. Data reported for the state RPS program more accurately reflects the change in generation over these years rather than data from EIA because the preliminary EIA renewables data for 2013 appears to be incomplete. For example, EIA shows a decline in hydropower generation in 2013 versus 2012 even though hydro generation was very low in 2012 due to a severe drought, and reporting for the state RPS shows a significant increase in in-state hydro generation during this time period.

Scenario 1: Replacement with coal. This scenario assumes that all of the 2012 generation from Kewaunee would be taken up by the newer coal plants (Elm Road and Weston 4), which have enough extra capacity to do so.

Scenario 2: Replacement with NGCC and coal. This scenario assumes that Kewaunee's 2012 generation would be made up by NGCC and coal units in the proportions in which they expanded from 2011 to 2013 (72% NGCC and 28% coal).

Scenario 3: Replacement with NGCC, coal and renewables. This scenario assumes that the generation would be made up by NGCC, coal and renewables units in the proportions in which they expanded from 2011 to 2013 for the fossil units or 2012 to 2013 for renewables (66% NGCC, 25% coal, and 8% renewables). Note that PSCW expects this amount of additional renewable generation to be added in 2014 irrespective of this rule.

Scenario 4: 12 month baseline from July 2013 to June 2014. For this scenario, the actual generation was analyzed for the 12 months after Kewaunee closed (July 2013-June 2014) based on data reported to EPA's CAMD and determined the estimated net[2] MWh of coal, NGCC and oil/gas boilers based on this data. This data should reflect actual in-state emissions without Kewaunee. Total estimated net fossil generation is very similar to the 2012 baseline + 2012 Kewaunee generation. Table 2 shows the differences between generation under this scenario and that in the 2012 baseline used in the proposal.

Table 3. Recalculated goals for Wisconsin under different scenarios. The bottom row shows the average of the scenarios.

#	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	**Interim**	**Final**
1	1,446	1,421	1,398	1,377	1,357	1,339	1,322	1,306	1,291	1,277	**1,353**	**1,277**
2	1,446	1,421	1,398	1,377	1,357	1,339	1,322	1,306	1,291	1,277	**1,353**	**1,277**
3	1,440	1,415	1,392	1,371	1,351	1,333	1,316	1,300	1,285	1,271	**1,348**	**1,271**
4	1,440	1,415	1,392	1,371	1,351	1,333	1,316	1,300	1,285	1,271	**1,347**	**1,271**
	1,440	***1,415***	***1,392***	***1,371***	***1,351***	***1,333***	***1,315***	***1,299***	***1,284***	***1,270***	***1,347***	***1,270***

Table 3 shows that the results of these corrections cluster into two sets based on whether renewables are allowed to compensate for some of the lost generation. The first set includes the first two scenarios, in which all of the generation is assumed to be replaced by fossil sources. The goals for these two scenarios are identical after applying building blocks 1 and 2 because the total amount of fossil generation remains the same as does the amount of NGCC capacity, so the emissions from coal and NGCC are the same after expanding NGCC operation to 70% of capacity. The second set includes replacement by fossil and renewables and the actual 12-month generation (2013-14 – in which renewable energy was in the system; scenario 4). These scenarios end up with identical goals, likely because both analyses rely on data from 2013. All of these scenarios give similar adjusted overall goals,

[2] CAMD's reported gross MWh was converted to net MWh based on the ratios observed from 2012 CAMD and EIA data.

with final goals of 1271-1277 lbs CO_2/MWh-net. All of these goals are less stringent in comparison with the proposed goal of 1203 lbs CO_2/MWh-net. These adjusted goals more accurately reflect the current status of Wisconsin's power sector, and EPA must adjust the state's goal in a similar manner to reflect the significant impact of the retirement of the Kewaunee Nuclear Plant.

If EPA uses a multi-year baseline as we recommend in our general comments, EPA should make the Kewaunee adjustment based on as many years of data as they can. EPA is unlikely to have three years of post-retirement data available but should use data from as long a time period as is available at that point.

2. EPA needs to make the following additional corrections to the data used in calculating Wisconsin's baseline.

A. EPA should include Bayfront unit 5, operated by Northern States Power Wisconsin, in the baseline. This unit fired both coal and natural gas in 2012, generating 6,214 MWh of electricity and emitting 5337.8 tons CO_2, based on EPA's Acid Rain Program database for 2012.

B. EPA must remove MWh and CO_2 emissions resulting from biomass fuels fired with fossil fuels at Manitowoc Public Utilities unit 9, as identified in Table 4.

Table 4. Generation and emissions data for Manitowoc Public Utilities unit 9.

Fuel	Heat Input (mmBtu)[a]	Electrical Generation (MWh-net)[b]	CO_2 (tons)[c]
Total	955,833	58,974	99,613
Biomass	119,940	**7,400**	**12,404**

[a] Total heat input is from EPA's Acid Rain Program for 2012. Heat input from biomass was calculated based on the tons of paper pellets reported in the WDNR 2012 Air Emissions Inventory and a conversion factor for solid biomass fuel (17.48 mmBtu/ton) from EPA's Greenhouse Gas Reporting Program.
[b] Total electrical generation is from the EIA-923 database for 2012. Electrical generation attributed to biomass was calculated based on the ratio of biomass heat input to total heat input.
[c] Total CO_2 emissions are from EPA's Acid Rain Program for 2012. The CO_2 emissions from biomass was calculated based on the calculated biomass heat input and an emission factor for solid biomass fuel (93.8 kg CO_2/mmBtu) from EPA's Greenhouse Gas Reporting Program.

C. EPA should include useful thermal output (UTO) in 2012 for the following power plants in Wisconsin, as part of the data derived using the eGRID methodology and used in the goal calculation:
   - Manitowoc Public Utilities
   - Valley
   - West Campus Cogeneration Facility

   Also note that in the October 2014 notice of data availability for the proposed rule, when seeking comment on including 2010 and 2011 as part of the baseline, EPA included UTO in 2010 and 2011 for these plants in the eGRID methodology.

D. EPA should remove MWh and CO_2 emissions resulting from biomass fuels fired from the baseline at Wisconsin combined heat and power (CHP) and industrial generators shown in Table 5 where the energy is not exported to the grid.

Table 5. Generation data for biomass at Wisconsin CHP and industrial generators.

Facility	Black Liquor	Biomass Gas	Sludge Waste	Wood Solid Waste	Other Biomass Solids
	Net Generation in 2012 (MWh)				
Biron Mill	0	0	0	22,305	0
Domtar Paper Company-Rothschild	0	0	0	5,745	0
Flambeau River Papers	0	0	0	24,399	517
Domtar Paper Company-Nekoosa	87,563	0	0	5,542	0
Kaukauna Paper Mill	62,878	0	0	11,661	0
Mosinee Paper	67,769	0	1,138	10,097	0
Packaging Corporation of America-Tomahawk Mill	15,361	2,597	0	29,629	43
Wisconsin Rapids Pulp Mill	216,029	0	0	59,398	0

CORRECTIONS TO EPA'S BUILDING BLOCKS

3. EPA should make the following corrections to building block 1

A. EPA should use fuel consumption data from the CAMD database to calculate real gross and net heat rates for individual EGUs.

B. EPA should exclude coal-fired EGUs that will be retired before 2020 (shown in Table 6) in calculating the heat rate improvement target for each state.

Table 6. Wisconsin coal-fired EGUs that will retire by 2020.

EGU	Action	Date of Retirement	Enforceability
Alma 4	Retirement	October 2014	Retired
Alma 5	Retirement	October 2014	Retired
Edgewater 3	Retirement	January 2016	EPA Consent Decree
Nelson Dewey 1	Retirement	January 2016	EPA Consent Decree
Nelson Dewey 2	Retirement	January 2016	EPA Consent Decree
Pulliam 5	Retirement	June 2015	EPA Consent Decree
Pulliam 6	Retirement	June 2015	EPA Consent Decree
Weston 1	Retirement	June 2015	EPA Consent Decree
Edgewater 4	Retirement/ Convert to NG	January 2019	EPA Consent Decree

C. EPA must assume the coal-fired EGUs listed in Table 7 will be operating past 2020 in applying both building blocks 1 and 2. In addition, specific corrections to the IPM model are marked in Table 7 (following page).

Table 7. Coal-fired EGUs that EPA should assume will continue operating past 2020, with specific corrections to IPM model results marked "*".

Generating Unit(s)	Issue
Bayfront 1,2 & 5	The IPM model should continue to operate Bayfront 1 and 2 as biomass fired EGUs and operate Bayfront 5 as a natural gas fired EGU.
Columbia Units 1 & 2	EPA's IPM Policy Run predicts both units will retire. This is contrary to Alliant's plans.*
Edgewater Unit 4 & 5	The IPM model should continue to run the Edgewater 4 EGU as natural gas-fired. EPA's IPM Base Run and Policy Run predict this unit to have a 3.6% and 0.9% capacity factor, respectively. This is contrary to Alliant's plans.*
Elm Road 1 & 2	The IPM model should continue to operate Elm Road 1 & 2.
Genoa Unit 3	The 2025 modeled capacity factor of over 80% may be possible when considering the NOx annual tonnage cap for the Genoa power plant, but is higher than any of Dairyland's internal forecasts.*
JP Madgett	The 2025 IPM has JPM in retirement prior to 2025. Dairyland's plans have JPM operating post-2025.*
Manitowoc Public Utilities 8 & 9	The IPM model should continue to operate MPU units 8 and 9.
Pleasant Prairie Unit 1	IPM model predictions in both the 2025 base and 2025 policy cases that show retirement of one unit at Pleasant Prairie in the 2025 policy case. We Energies has no plans to retire either unit at the Pleasant Prairie Power Plant in the foreseeable future.*
Presque Isle	IPM model predictions in both the 2025 base and 2025 policy cases that show retirement of the Presque Isle power plant. This plant is currently operating under a system support resource (SSR) agreement with MISO.*
Pulliam Unit 7 & 8	The IPM model should continue to operate Pulliam 7. The 2025 IPM has Pulliam Unit 8 in retirement prior to 2025. Wisconsin Public Service Corporation's plans have this unit operating post-2025.*
South Oak Creek 5 to 8	The IPM model should continue to operate South Oak Creek 5 through 8.
Weston 2, 3 & 4	The IPM model should continue to operate Weston 3 and 4. The IPM model should continue to operate Weston 2 as a natural gas-fired steam boiler.
Valley	IPM model predictions in both the 2025 base and 2025 policy cases that show retirement of the Valley power plant. This plant is being converted from coal to natural gas and is not being contemplated by We Energies for retirement in the foreseeable future.*

4. EPA should make the following corrections to building block 2

Thermal energy produced at NGCC units should be converted into equivalent MWh and be included in the calculation for building block 2. For example, Table 8 contains 2012 data from Madison Gas and Electric for their West Campus Cogeneration Facility.

Table 8. 2012 Generation and thermal energy output for the West Campus Cogeneration Facility.

Unit Parameter	Value
Total Gross 2012 Generated (MWh)	277,559
Net 2012 Generation (MWh)	256,470
Total 2012 Useful Thermal (mmBtu)	430,240

5. EPA should make the following corrections to building block 4

A. EPA should correct the 2012 energy efficiency (EE) data for Wisconsin

Wisconsin identified several problems with the EE data reported to EIA that have a small impact on the size of Wisconsin's EE goal. The Focus on Energy program slightly underreported savings from the program and several utilities over-reported their EE savings (i.e., reported savings that had already been reported by the Focus on Energy program; these discrepancies are detailed in Table 10, following page). These reporting issues have been addressed and will not occur in future years, but Wisconsin encourages EPA to work with EIA to clarify reporting instructions to utilities and co-ops to ensure that similar errors do not occur in the future. When the reported values are corrected, Wisconsin's overall goal becomes slightly less stringent, as shown in Table 9.

Table 9. Corrections to Wisconsin's goals from correcting energy efficiency data.

	2012 Savings (GWh)	Interim Goal (lb CO2/MWh)	Final Goal (lb CO2/MWh)
Used by EPA	722	1281	1203
Corrected verifiable savings	629 (13% lower)	1286	1205

Table 10. Differences between Wisconsin energy efficiency savings reported to EIA and best estimates from the Public Service Commission of Wisconsin for 2012.

	Savings due to energy efficiency programs (kWh)				
	EIA Report	**PSCW Estimate**	**Difference**	**% Difference**	**Notes**
Statewide Energy Efficiency Program		*Source: CY12 Focus Evaluation Report*			
Focus on Energy Program Verified Gross Savings (Minus Renewables)	589,000,600	614,588,138	25,587,538		Reason for difference is unclear; person who did the reporting no longer with program.
Investor Owned Utility Voluntary/Stipulation Programs		*Sources: Program Evaluations filed with PSC*			We Energies, Xcel and WPS had other programs that were correctly reported under the Focus on Energy Program.
Wisconsin Public Service Corporation Stipulation Community Programs	0	2,280,288	2,280,288		WPS didn't report any savings due to lack of data availability at the time of reporting deadline.
Wisconsin Power & Light Shared Savings	935,000	1,375,137	440,137		WPL appears to have reported net savings rather than gross.
Madison Gas & Electric	34,732,000	0	-34,732,000		All of the savings reported by MG&E were also reported by the Focus on Energy program. MG&E will be correcting this error for future reports.
Regional Power Company		*Source: WPPI*			
WPPI Energy	80,263,000	10,879,032	-69,383,968		WPPI reported savings that are also reported by the Focus on Energy program, as well as savings from out-of-state member utilities. WPPI achieved additional savings through voluntary programs that were not counted by Focus on Energy. WPPI provided an estimate of savings from those programs and has corrected this error for future reports.
Municipal Utility and Electric Cooperative Programs		*Source: CTC reports submitted to PSC and EIA reports*			
Commitment to Community Programs	10,400,000	13,492,244	3,092,244		A few utilities with CTCs didn't report to EIA.
Other utilities*	7,497,000	3,407,000	-4,090,000		Marshfield, which reported more than half of the savings in this category, confirmed that all of its savings were reported by the Focus on Energy program and that this error has been corrected for future reports. It's possible some of the other utilities did the same, but given the generally small numbers, PSCW did not investigate further.
Total accepted savings	**722,827,600**	**646,021,839**	**-76,805,761**	**89.4%**	Includes all savings reported or that PSC has documented.
Total Verifiable Savings	**722,827,600**	**629,122,595**	**-93,705,005**	**87.0%**	Only includes those savings subject to formal, rigorous calculation: Focus on Energy, IOU programs, and WPPI.**

*Other utilities include Clark Electric Coop, Eau Claire Electric Coop, City of Marshfield, Oakdale Electric Coop, Pierce-Pepin Coop Services, Polk-Burnett Electric Coop, Price Electric Coop Inc, Scenic Rivers Energy Coop, Taylor Electric Coop, and Vernon Electric Coop.

**Focus and IOU programs are evaluated by third-party professionals; WPPI program savings are calculated based on sound, consistent methods applied by qualified WPPI staff. Programs at municipal utilities and electric coopereratives are not rigorously evaluated, in part because most activity occurs at coops over which PSCW has limited regulatory authority.

B. EPA should correct the percent of Wisconsin electrical sales generated within the state

In the TSD spreadsheet, "20140602tsd-state-goal-data-computation", EPA uses a value of 83.97% for Wisconsin's state generation as a percent of sales. However, when we attempted to reproduce this value using data from EIA, we calculated 86.15%. We have not found an explanation of how EPA calculated this value, but we explain our calculation in Table 11. EPA should either use the value determined by Wisconsin or explain how they calculated their value and justify why this value is more appropriate than the one calculated by the state.

Table 11. Calculation of state generation as % of sales for Wisconsin.

Parameter	Value	Source
2012 Total MWh (sales x 1.0751)	73,988,479 MWh	EPA's spreadsheet (TSD state goal data computation)
2012 Wisconsin generation	63,742,910 MWh	www.eia.gov/electricity/data/state
WI generation as % of WI sales Calculated by Wisconsin Calculated by EPA	 86.15% 83.97%	 Calculated EPA's spreadsheet (TSD state goal data computation)

CORRECTION TO EPA'S TECHNICAL SUPPORT DOCUMENTS

6. EPA should correct the year of adoption of Wisconsin's Energy Efficiency Resource Standard

In EPA's TSD on GHG Abatement Measures, EPA reports in Table 5-3 that Wisconsin's Energy Efficiency Resource Standard (EERS) was adopted in 2011. In fact, the Focus on Energy program was established in 1999 by Wisconsin Act 9 and began operating in July 2001. This makes Wisconsin's EERS one of the longest-running in the nation. EPA should correct this error in any future publications on this issue.

CORRECTIONS TO EPA'S USE OF THE IPM MODEL

7. The contradictory projections in the IPM model outlined in Table 12 should be corrected.

Table 12. Corrections to the IPM model results.

Generating Unit(s)	Issue
Edgewater Unit 5	A dry scrubber is scheduled to begin operation in 2017; however, it is not included in the IPM modeling assumptions.
Riverside	A SCR is currently installed on this unit; however, it is not included in the IPM modeling assumptions.
Seven Mile Creek Unit 4	The 2025 IPM has Unit 4 listed with a 2.1 MW capacity; the actual capacity is 975 kW.

8. The corrections outlined in Table 13 should be made to the NEEDS database.

Table 13. Corrections to the NEEDS database.

Generating Unit(s)	Issue
	Dairyland Power Cooperative
Genoa Unit 3	• Capacity MW is listed as "325," but because of a conversion to sub-bituminous rather than bituminous fuels, the current capacity for G-3 is 296 MW net. • 2012 heat rate (Btu/kWh, net) is 10,830 (calculated using EIA net generation and CAMD heat input data), not 10,133 as is currently reported in NEEDS 5.13v3. • "Flue Gas Conditioning Flag" should be "No." • "Mercury Controls" lists ACI being online at G-3 in 2009; ACI will be online in 2015.
JP Madgett	• 2012 heat rate (Btu/kWh, net) is 11,380 (calculated using EIA net generation and CAMD heat input data), not 10,652 as is currently reported in NEEDS 5.13v3. • "Scrubber Efficiency" and "Scrubber Efficiency MATS" should both be 80% rather than the currently listed "53." • "NOx Post-Comb Control" lists "SCR" and "SCR Online Year" is listed as "2010." The JPM SCR will be operational spring of 2016.

Generating Unit(s)	Issue
Northern States Power Corporation	
Bayfront Unit 5	Capacity should be 30 MW instead of 20 MW.
We Energies	
South Oak Creek Unit 5	Capacity MW is listed as "299.2," but the current capacity should be 262 MW.
South Oak Creek Unit 6	Capacity MW is listed as "299.2," but the current capacity should be 265 MW.
South Oak Creek Unit 7	Capacity MW is listed as "317.6," but the current capacity should be 298 MW.
South Oak Creek Unit 8	Capacity MW is listed as "324.0," but the current capacity should be 314 MW.
Wisconsin Power and Light	
Riverside Energy Center – STG 1	Capacity should be 277.1 MW instead of 299.7 MW.
Riverside Energy Center – CTG 1	Capacity should be 198.9 instead of 198.0 MW.
Riverside Energy Center – CTG 2	Capacity should be 198.9 instead of 198.0 MW.
Wisconsin Public Service Corporation	
Eagle River	Units no longer exist.
Glenmore Turbines	Unit no longer exists.
Fox Valley Energy Center	Facility closed in June 2013.
Oneida Casino	Units no longer exist.
Point Beach Nuclear Plant Unit 5	IC engine unit is for black start and emergency operation only.
Juneau Unit 31	Unit is currently non-operational and has an unknown fate.
Ridgeview Landfill	This facility is a non-utility generator operating without performance or availability guarantees, and should not be modeled as an active generator as it has no obligation to continue generating energy.
Weston Unit 2	Unit is shown as being retired prior to 2016. Weston 2 can operate on natural gas and in order to comply with the EPA Consent Decree the plan is to operate Weston 2 on natural gas starting June 2015 rather than retire prior to 2016.
Winnebago County Landfill	This facility is a non-utility generator operating without performance or availability guarantees, and should not be modeled as an active generator as it has no obligation to continue generating energy.

9. EPA used the IPM model to estimate costs in complying with the proposed rule requirements. The following corrections should be made in this costing analysis.

A. At a minimum EPA must run the EGUs list in comment 3.C. Utilities have made significant investments in these EGUs to continue their operation for the foreseeable future. In response to the CAIR, CSAPR, BART, Visibility and MATS rules, the utilities have recently had considerable expenditures. At a minimum, EPA must include current unpaid costs for individual EGUs. These expenditures will impact the way IPM dispatches resources or, at a minimum, affect the total cost of the proposed CO_2 rule. EPA must include these unpaid costs in the base information and identify when EGUs are retired and costs are not being paid through operation of the EGU. EPA must acknowledge in the analysis that the less EGUs with existing cost operate, the longer it will take to pay the debt.

B. EPA should include the cost for both additional natural gas pipeline and storage capacity. This includes assuming expansion of all existing natural gas pipeline to existing NGCC and CT plants to ensure firm supply.

C. EPA should include the cost to utilities of contracting natural gas storage in order to ensure firm supply.

WISCONSIN'S COMMENTS ON EPA'S PROPOSED CLEAN POWER PLAN
PART 4:
WISCONSIN'S PRE-PROPOSAL ACTIONS TO REDUCE CO_2 EMISSIONS FROM THE POWER SECTOR

Wisconsin has already significantly reduced its CO_2 emissions from power plants through a broad range of actions. CO_2 emissions from Wisconsin's power sector declined by 16% from 2005 to 2012.[1] These reductions occurred due to a combination of:

1) Improved heat rates at Wisconsin's fossil fuel-fired power plants,
2) Expanded renewable electricity generation as part of Wisconsin's Renewable Portfolio Standard and green power purchasing agreements,
3) Expansion of energy efficiency through Wisconsin's utility-funded energy efficiency program, Focus on Energy, and
4) An extended power uprate at the Point Beach Nuclear Plant.

Wisconsin utilities and others invested billions of dollars to make these changes, as shown in Table 1. It is essential that the state receive credit for these early actions when complying with the Clean Power Plan. These measures were discussed in detail in our December 13, 2013 comments to EPA (attached) and are outlined briefly here.

Table 1. Selected investments made by Wisconsin utilities and others from 2000 to 2013.

Category	Action	Capital Cost (million $)	Capacity (MW)
Existing Plants	Efficiency upgrades	$184	
	Air Pollution Control Equip.	$3,080	
		$3,264	
New Capacity	Supercritical Coal	$2,905	1,753
	Natural Gas Combined Cycle	$1,603	2,150
		$4,508	**4,200**
New Renewable	Wind	$2,061	1,018
	Biomass	$255	100
		$2,316	**1,118**
Electricity Efficiency Programs	Focus on Energy Program	**$469**	
Extended power uprate at Point Beach Nuclear Plant		Undisclosed (estimated: $1 billion)[2]	**162**
Total Investments		**$11.6 billion**	

[1] CO_2 emissions increased between 2012 and 2013 in part because increased generation at fossil fuel-fired plants was needed to make up for the loss of carbon-free generation from the closure of Kewaunee Nuclear Plant in May of 2013. This issue is discussed in greater detail in the Technical Corrections document. Prior to its closure, Kewaunee provided 7% of Wisconsin's total electricity generation. Total CO_2 emissions from Wisconsin's power sector decreased only 3% from 2005 to 2013.

[2] Cost is estimated based on the cost per kWh for similar projects by the same company, NextEra Energy's affiliate, Florida Power & Light, and contractor, Bechtel. The uprates at Turkey Point and St. Lucie cost $6500 per kW. http://www.psc.state.fl.us/publications/pdf/electricgas/FPL_2014.pdf

1. Wisconsin's utilities have significantly improved heat rates at the state's fossil fuel-fired power plants.

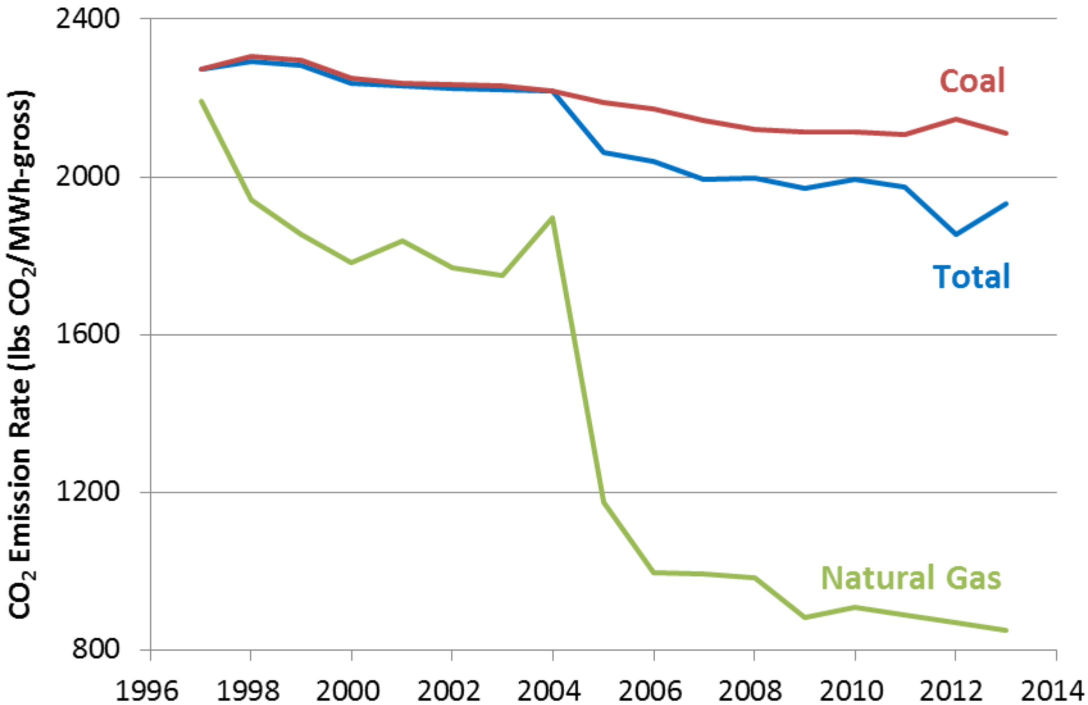
Wisconsin's utilities have improved heat rates from the fossil fuel-fired fleet by 2% since the early 2000s via a combination of efficiency upgrades, retirements of older, inefficient capacity, and construction of new, more efficient units. The improvements in coal unit heat rates are discussed in detail in our building block 1 comments[3], and Table 2 lists retirements, new capacity and fuel switching that occurred at fossil fuel facilities. These changes reduced CO_2 emission rates at coal EGUs by 2% and at natural gas-fired EGUs by 26% by 2012 from 2005 levels,[4] as shown in Figure 1. Overall emissions rates declined by 10% over the same time period.

Table 2. List of power plants in Wisconsin that retired, began operations, or switched fuels since 1997 and planned future changes.

Facility	Capacity (MW)	Units	Type of facility and date changed
Plant Retirements			
Alma	63	1-3	Coal, retired 2005
Manitowoc	46	5-7	Coal, retired 2010
Port Washington	322	1-4	Coal, retired 2002 & 2004
Pulliam	53	3-4	Coal, retired 2008
Rock River	150	1-2	N. gas, retired 2009
New Generation Capacity			
Elm Road	1234	1-2	Coal, operational 2009 & 2010
Fox Energy	635	1-2	N. gas combined cycle, operational 2005/2006
Port Washington	1090	11, 12, 21, 22	N. gas combined cycle, operational 2005/2008
Riverside Energy Center	600	1-2	N. gas combined cycle, operational 2005
West Campus Cogeneration	150	1-2	N. gas combined cycle, operational 2005
Weston	519	4	Coal, operational 2008
Fuel Switching			
DTE Stoneman	50	1-2	Former coal-fired plant, converted to firing wood in 2010
Blount	190→100	3, 5-9, 11	Formerly coal-fired plant, retired 90 MW and converted the rest to natural gas, 2011

[3] Part 2: Comments on Building Blocks.
[4] Reductions from 2005 to 2013 were even larger: 3.6% for coal-fired EGUs and 32% for natural gas-fired units. The total fossil sector rate declined by 6% over this time period.

Figure 1. CO_2 emission rates for coal-fired, natural gas-fired and average fleet power plants in Wisconsin.

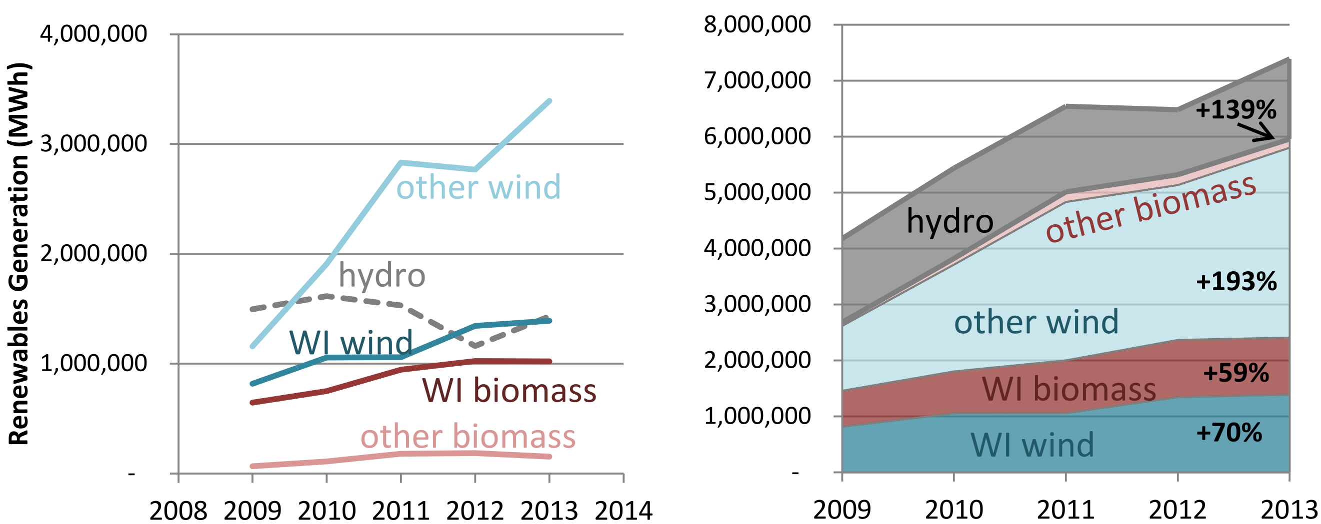


Emissions rates were derived from data obtained from EPA's Clean Air Markets Division, http://ampd.epa.gov/ampd/.

2. Wisconsin has dramatically increased renewable energy generation both in the state and in our neighboring states.

Wisconsin's Renewable Portfolio Standard (RPS) requires that 10% of electricity generation for the state comes from renewable sources by 2015. Wisconsin utilities met this standard in 2013, two years ahead of schedule, and are expected to continue to exceed the standard through at least 2020 based on PSCW forecasts.[5] As shown in Figure 2, Wisconsin entities generated or purchased almost 6 million MWh of non-hydroelectric RE in 2013. Over the last 4 years, in-state generation (used for RPS compliance and sold via green power purchasing) of wind and biomass power has increased 70% and 59%, respectively, whereas out-of-state generation of wind and biomass energy has increased 193% and 139%, respectively. Wind energy generated for Wisconsin in neighboring states has increased faster than that generated in the state because many of our neighbors have much greater wind resources and can generate wind energy at a much lower cost. As discussed in the comments on building block 3a[6], Wisconsin utilities own and operate roughly 35% of this out-of-state generation. We estimate that the non-hydroelectric renewables avoided emission of roughly 5 million tons of CO_2 in 2013.

Figure 2. Renewable energy used for compliance with Wisconsin's Renewable Portfolio Standard and purchased via green power purchasing agreements, generated in Wisconsin and in "other" states. The plot on the left shows values for each source and the one on the right shows the cumulative MWh and % increase in each source.



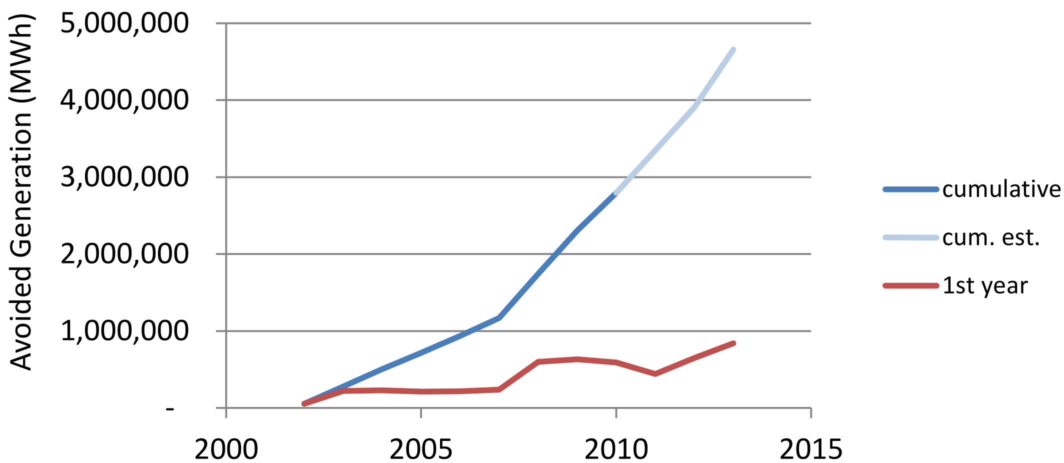
Note: The values shown list the percent increase in that generation source over this four-year period. Data are from the Public Service Commission of Wisconsin's RPS Compliance Reports, http://psc.wi.gov/renewables/rpsCompliance.htm.

[5] Public Service Commission of Wisconsin memorandum, 2013 Renewable Portfolio Standard Summary Report, http://psc.wi.gov/apps35/erf_search/content/SearchResult.aspx.
[6] Part 2: Comments on Building Blocks.

3. Wisconsin is a national leader in energy efficiency, and our Focus on Energy program has greatly expanded energy efficiency in the state.

Wisconsin's Focus on Energy program is funded by a rate payer add-on fee charged by the state's utilities and provides incentives for installation of energy efficiency (and renewable energy) measures. This program is well-established and highly effective, and it includes rigorous measurement and verification methods. As shown in Figure 3, first-year savings (from measures installed that year) have increased from 56,000 MWh in 2002 to over 800,000 MWh in 2013. Estimated cumulative ("lifetime") savings from measures in place in 2013 were over 4,500,000 MWh. We estimate that these measures avoided emission of roughly 3.8 million tons of CO_2 in 2013.

Figure 3. Estimated gross electricity generation avoided due to the Focus on Energy program. Avoided generation is shown on a first-year (incremental) and a cumulative basis.

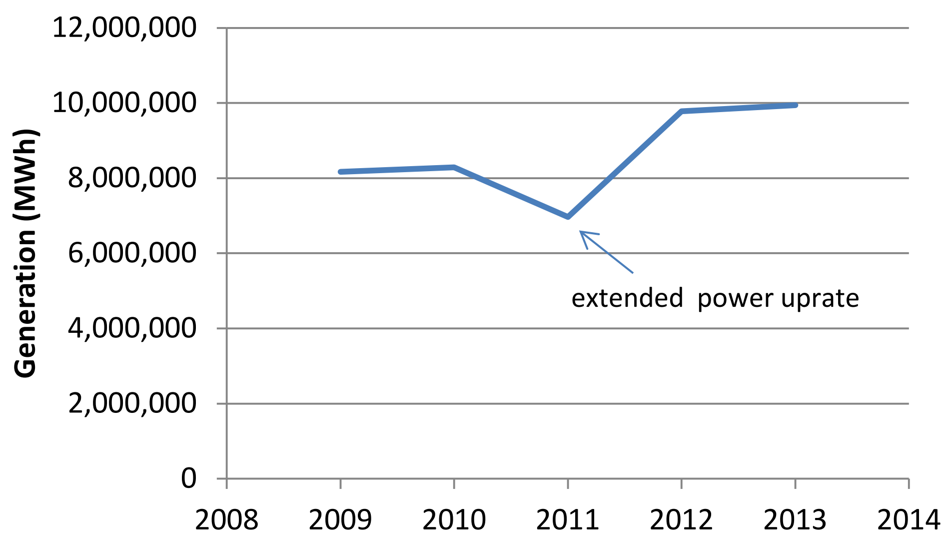


Data are from the Public Service Commission of Wisconsin's Focus on Energy Evaluation Reports, https://focusonenergy.com/about/evaluation-reports. Note that cumulative values for 2011-2013 were not calculated by the program, but were estimated by WDNR based on average measure lifetimes.

4. Wisconsin's Point Beach Nuclear Plant significantly increased its generation via an extended power uprate in 2011.

In 2011, the Point Beach Nuclear Plant underwent an extended power uprate to increase generation. This uprate was supported by a power purchase agreement with Wisconsin's WPPI Energy. As shown in Figure 4, total yearly generation increased roughly 1,600,000 MWh, a 20% increase, from before the uprate in 2009-10 to after the uprate in 2012-13. This uprate significantly increased generation of carbon-free baseload power, offsetting generation (and CO_2 emissions) from fossil fuels.

Figure 4. Generation at the Point Beach Nuclear Plant before, during, and after its extended power uprate.



Data from the Energy Information Agency (EIA), http://www.eia.gov/nuclear/generation/index.html.

WISCONSIN'S COMMENTS ON EPA'S PROPOSED CLEAN POWER PLAN
PART 5:
LEGAL COMMENTS

EPA's authority under the Clean Air Act ("Act") to regulate air pollution sources is expressly limited by Congress in both the extent to which they can compel reductions and the methods available to achieve the desired results. In the technical comments on the proposed Clean Power Plan, Wisconsin raises specific factual and practical concerns with each building block under the proposed rule. The issues identified as part of Wisconsin's technical comments also support broader legal concerns that EPA has acted in an arbitrary and capricious manner and exceeded its authority under Section 111of the Act in the proposed Clean Power Plan.

Specifically, Wisconsin is concerned that EPA lacks and/or exceeds it authority to dictate the extent of greenhouse gas ("GHG") controls as follows:

1. EPA is exceeding its authority by setting individual state emission targets under Section 111(d).

EPA's authority to set emission guidelines for a given source based on the best system of emission reductions ("BSER") does not correlate to authority to set a statewide emission goal. This issue was also raised in the attached white paper from 18 state attorney generals, including Wisconsin's Attorney General J.B. Van Hollen. Additionally, the methodology used by EPA to establish state goals is inequitable amongst the states. *See* Wisconsin's Comments on EPA's Proposed Clean Power Plan, Part 1, General Comments #1 and 27; and Part 2: Building Block Comments #31, 32, 33, and 35.

EPA's role under Section 111(d) is limited to requiring a state to adopt standards and providing guidance to states describing the system of emission reductions deemed acceptable to EPA and the criteria for judging the adequacy of a state plan. The determination of the final, substantive emission standards is the sole right of the states, allowing Wisconsin to account for state specific and case-by-case considerations. In multiple parts of our technical comments, Wisconsin raises concerns whether EPA has adequately considered all of the state specific factors in identifying the reductions in each building block and how this is reflected in the ultimate state goal. *See e.g.* Wisconsin's Comments on EPA's Proposed Clean Power Plan, Part 1: General Comments #29; and Part 2: Building Block Comments #4, 17, 18, 19, and 31.

2. Section 111(d) of the Act requires each state to submit a plan establishing "standards of performance for any existing source", not an entire electric generating system.

EPA's proposed BSER for greenhouse gas emissions from electricity generating units ("EGUs") is established for the entire electric generating system instead of for distinct sources of air pollution. EPA's consideration of the entire electrical system and performance standards outside of the control of a single stationary source when setting the BSER is a significant deviation from the historical approach of reducing emissions from individual power plants and is inconsistent with the intent and purpose of Section 111 of the Clean Air Act. Every existing source guideline promulgated by EPA has been based on measures that the regulated source can incorporate into its design or otherwise implement on its own. In contrast, building blocks 2 through 4 of EPA's proposal rely on "outside the fence line" measures that are beyond the control of regulated sources. This is contrary to the language, intent, and historical application of Section 111(d).

3. Neither the Clean Air Act nor Wisconsin's air pollution statutes currently provide the authority to regulate "outside the fence" of a designated stationary source or dictate distribution of energy resources.

The proposed Clean Power Plan considers reductions "outside the fence" of a designated electric generating utility in the identified building blocks. Building blocks such as deployment of renewables and energy efficiency are reductions outside of the direct control of the regulated EGU. By allowing measures such as expanding generation at low or zero-carbon generating facilities to qualify as BSER, EPA is essentially interpreting the Act well beyond its intent as an air pollution control law into the realm of dictating state and national energy policy.

Wisconsin's authority under current state law is limited to stationary sources, a term specifically defined by statute. Section 285.01(41), Wis. Stats., defines "stationary source" as "any facility, building, structure, or installation that directly or indirectly emits or may emit an air contaminant only from a fixed location." The defined term "stationary source" is also referenced in Wisconsin's authority to adopt standards of performance promulgated under section 111 of the Clean Air Act. See 285.27(1), Wis. Stats. "If a standard of performance *for new stationary sources* is promulgated under section 111 of the federal clean air act, the department shall promulgate by rule a similar emission standard." (emphasis added)

4. EPA's proposed BSER is not achievable in practice for Wisconsin, does not properly evaluate all considerations specified under the Act, and does not qualify as a system of emission reduction

Throughout Wisconsin's comments is the recurring theme that EPA's proposed building blocks are not achievable in practice. For example, Wisconsin argues that EPA did not consider what is achievable in practice for the specific units being controlled, when the interactions between building blocks are considered, or when applied to individual states. *See e.g.,* Wisconsin's Comments on EPA's Proposed Clean Power Plan, Part 2: Building Block Comments #2, 3, 4, 16, 20, and 22.

EPA must consider all factors specifically dictated to EPA by Congress under Section 111(d) when setting the BSER and the resulting emission guidelines. These include such factors as cost of achieving reductions and impact on energy requirements. A specific example for Wisconsin is our comment #8 in Part 2: Building Block Comments, which argues that EPA did not consider the remaining life of coal fired EGUs when considering heat rate improvement capability. Many of Wisconsin's EGUs considered for heat rate improvements under the proposed Clean Power Plan have already been converted to natural gas fired boilers or are otherwise slated for retirement in advance of the Clean Power Plan compliance date.

Not only are EPA's proposed building blocks not achievable as applied to Wisconsin, but the proposed building blocks do not qualify as a system of emission controls as that term has ever been understood or historically applied under section 111 of the Act. A "system" under section 111 has always consisted of specific work practices or controls that an emission unit owner can implement to achieve a known reduction in a pollutant. EPA's four building blocks as proposed under this rule are outside the coordination and control of the owner or operator, are not recognizable "systems" of work practice or control that can be applied to an emission unit, and cannot guarantee a certain, conclusive GHG emission reduction when implemented as a whole. Our comments #2 and 3 in Part 2: Building Block Comments further underscore the specific deficiencies relative to adequate identification of a

BSER. Given the foregoing, the proposed building blocks cannot rise to even be a BSER capable of being found "adequately demonstrated" by the EPA, as required by the definition of a "standard of performance" in §111(a)(1). Thus, the proposal at the outset is unlawful for want of a threshold "standard of performance" capable of any reasonable assessment as to effectiveness and lawfulness. The proposal of the building blocks as a BSER is fundamentally arbitrary and capricious.

5. **Wisconsin is also concerned whether EPA has proposed regulation of GHG emissions from EGUs following the proper procedural requirements and under the appropriate section of the Act.**

The U.S. Code version of Section 111(d) of the Clean Air Act authorizes regulation of existing sources, but only for those source categories *not* already regulated under Section 112 of the Clean Air Act. EGUs are currently regulated under Section 112 of the Clean Air Act. This issue was raised in the attached September 9, 2014 letter to President Obama from 15 governors, including Wisconsin Governor Scott Walker.

6. **EPA cannot finalize the Clean Power Plan under Section 111(d) of the Act unless it has established regulations for new EGU sources under Section 111(b) of the Act**

Section 111(b) of the Act requires EPA to identify a category of new stationary sources contributing significantly to a given air pollutant before it can regulate the category for existing sources under Section 111(d) of the Act. EPA has not yet finalized its new source performance standards regulating EGU GHG emissions as proposed on January 8, 2014 *(*79 FR 1430*)*.

7. **EPA must make all information and documents upon which the proposed rule is based available in the docket**

Full access to documents used by EPA in its development of the proposed rule is essential for states in the development of their plans.

8. **EPA's proposed schedule for states to develop state implementation plans and implement the Clean Power Plan is arbitrary and not achievable.**

EPA's current schedule for development, submittal of plans and for compliance with the identified goals is unreasonable given the expected amount of planning, stakeholder engagement, rulemaking, need for legislative authorization and potential coordination with other states needed to fully implement the Clean Power Plan. *See* Wisconsin's Comments on EPA's Proposed Clean Power Plan, Part 1: General Comments #2, 5, and 10; and Part 2: Building Block Comments #23.

The Clean Air Act at 42 USC 7411(d) requires EPA to establish a procedure for submittal of state plans similar to those required under section 110 of the Act. The regulation of greenhouse gas has more complex considerations than the well-established planning process for criteria pollutant ambient air standards. Given the wide reaching implications of the proposed rule and the varied means identified to achieve the standard, EPA must set a reasonable time schedule that respects state authorities and considers all steps needed to fully implement the proposed Clean Power Plan.

WISCONSIN'S COMMENTS ON EPA'S PROPOSED CLEAN POWER PLAN
PART 6:
EGEAS MODELING OF THE WISCONSIN ELECTRIC UTILITY SYSTEM
CONDUCTED BY THE PUBLIC SERVICE COMMISSION OF WISCONSIN

The Public Service Commission of Wisconsin (PSCW) performed modeling of Wisconsin's electric utility generation system to evaluate the potential impacts and costs of the proposed Clean Power Plan. This part of Wisconsin's comments presents the methodology and results applied in performing the modeling. The modeling was performed using the Electric Generation Expansion Analysis System (EGEAS) model licensed by the Electric Power Research Institute. The directive for EGEAS modeling was to determine the costs for compliance with the proposed rule for the entire compliance period if Wisconsin were to approach it from a state-only perspective.

These results should be considered preliminary and should not be construed as Wisconsin endorsing any of the model runs as a feasible or cost-effective compliance effort or in support of the proposal. Conducting this modeling required numerous assumptions in critical areas due to ambiguities in EPA's proposal. The model excludes costs attributable to electric and gas infrastructure upgrades and assumes a high penetration of demand side resources, such as energy efficiency, will be able to be attained at a low cost. Ultimately, whatever plan Wisconsin develops to comply with this proposal will greatly increase costs to the state.

1. Modeling included several assumptions due to the ambiguity of EPA's proposal.

PSCW conducted several EGEAS modeling runs, including a reference case run, to evaluate EPA's proposal under various conditions and assumptions. In all of the runs, the model was allowed to optimize electric generating units (EGU) dispatch in meeting the same electricity load. The electricity load was projected by applying the MISO growth rate of 0.8% per year based on 2012 Wisconsin electricity sales plus transmission losses. In-state and out-of-state EGUs dedicated for Wisconsin plus additional market purchases were dispatched in an optimized manner. EGEAS estimates 13 percent of Wisconsin's electricity to be generated from out-of-state capacity in 2014, plus a smaller percentage of out-of-state energy purchases. The in-state EGUs available for operation under the EGEAS model do not include the Kewaunee nuclear plant that was shutdown in 2013.

In all of the runs, the model was allowed to pick from various new options in meeting CO_2 requirements and load demand, including additional energy efficiency measures, renewable energy generation, natural gas combined cycle, and combustion turbines.

Assumptions were also made so that the building blocks presented by the proposal could be applied realistically to Wisconsin's fleet. For building block 1, a 6% heat rate improvement is not feasible for Wisconsin's coal-fired fleet. Wisconsin identified elsewhere in our comments[1] that the maximum HRI

[1] Part 2: Comments on Building Blocks, comment 6.B.

potential may range from 0.5% to 2.3% of the gross heat rate. PSCW's EGEAS model runs assumed an ambitious 3% heat rate improvement for units that were not built after 2005, supercritical units, or retiring during the compliance period. Because the results tended to show coal-fired generation running at less than full capacity, which often negates HRI investments, no additional improvements were included for any of the limit runs.

Due to the ambiguity of the proposed rule, multiple assumptions were made to determine the final mass-based goal for Wisconsin. For example, the emission rate formula, as stated in the draft rule, uses "in-state, non-hydro renewable resources" in setting the baseline renewable generation in the denominator of the formula. This may be correct if Wisconsin was an island that did not import or export electricity. However, Wisconsin is an importing state connected to the rest of MISO, and relies heavily on out-of-state renewable resources to meet the renewable portfolio standard (RPS). While this renewable generation might not be in Wisconsin's emission rate baseline, this generation would most likely be in Minnesota's and Iowa's baseline. If the current rule counts these out-of-state renewable resources for the states in which they are located, this will change these respective states' baselines and this will make their goals more stringent.

Another assumption made for the purpose of modeling was to increase the mass-based goal proportional to the amount of non-renewable energy imported from other states. The treatment of out-of-state resources dedicated to Wisconsin is not clearly addressed in the Clean Power Plan as proposed. For example, Minnesota may be responsible for reducing carbon emissions attributable to the non-renewable energy it exports to Wisconsin. As a result, there will be extra costs associated with compliance in exporting states. As it is unlikely that ratepayers in exporting states will cover the costs associated with generation allocated for supplying out-of-state load, these costs will be passed on to Wisconsin ratepayers in some form, either through increased rates for imported electricity or through construction of new generation in Wisconsin to meet the load currently being met with imports. Thus, it is necessary to take into account out-of-state resources in determining an actual cost of compliance to Wisconsin ratepayers.

2. Several scenarios were modeled and evaluated by Wisconsin.

PSCW conducted the multiple runs with specific fixed conditions. Table 1 (following page) summarizes the costs and emissions reductions of the different model runs, which are explained in detail below.

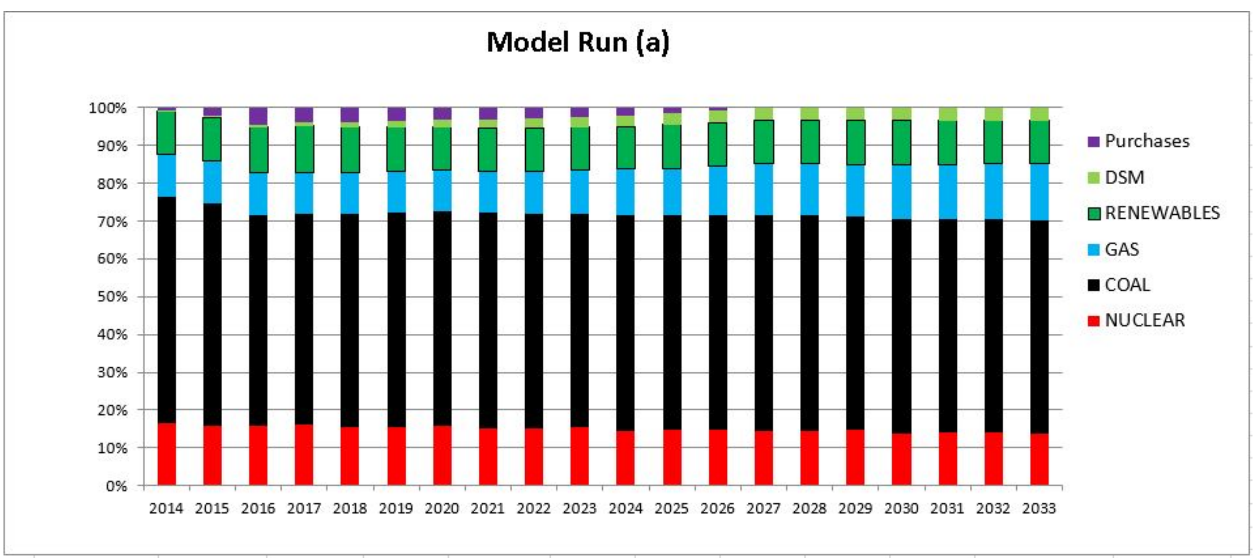
Table 1. Summary of PSCW's EGEAS Model Runs.

Wisconsin EGEAS Model Runs		
	Cost Above Reference Case	**CO_2 Change from Today (%)**
Runs	(In $Millions)	(In %)
(a) Reference Case	$ -	9.3%
(b) Building Blocks as Designed	$ 3,279	-15.6%
(c) Excluding Emissions from New NGCC with $4/MMBTU	$ 4,238	-34.3%
(d) Excluding Emissions from New NGCC with $6/MMBTU	$ 7,469	-34.5%
(e) Including Emissions from New NGCC with $4/MMBTU	$ 9,576	-35.0%
(f) Including Emissions from New NGCC and Replacing Nuclear	$ 13,091	-34.9%

A. Model Run (a): Reference Case

The reference case included the assumptions above and assumed no carbon regulation was in place. This model also assumed and that current energy efficiency and renewable energy programs would continue in the same manner in the future, and disallowed the construction of new coal-fired generation.

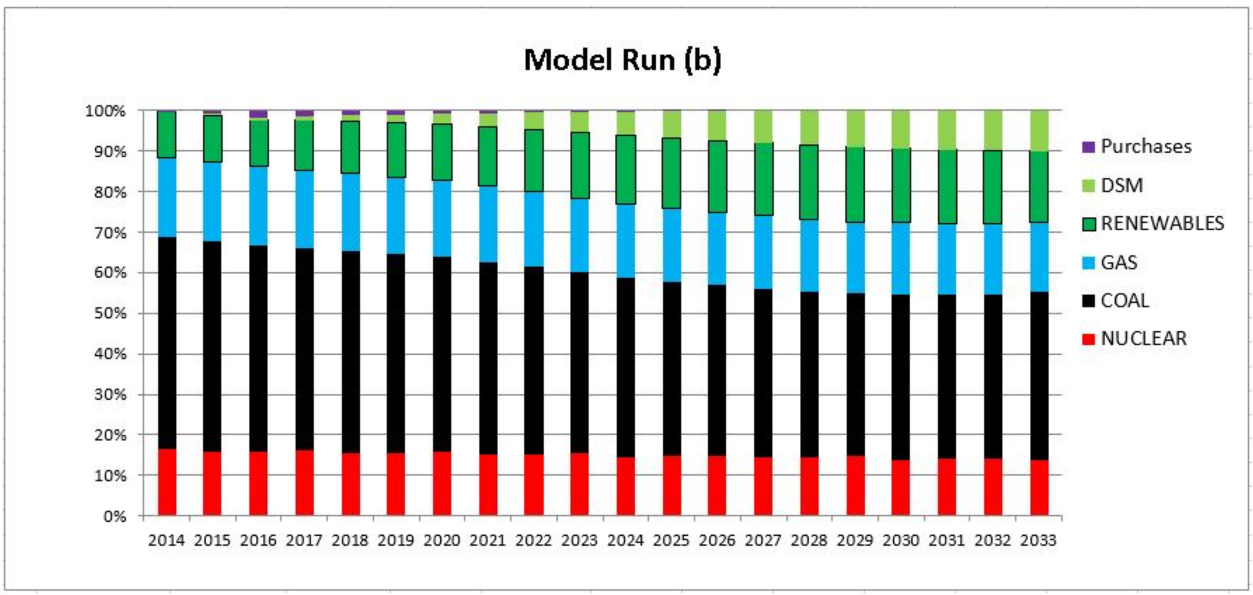
The reference case resulted in 9.3% increase in mass-based CO_2 emissions from the baseline level, which is attributable solely to the load growth in the model. This does not necessarily translate to an increase in rate-based emissions, which is an important distinction. As noted in Part 4 of our comments, CO_2 emissions have decreased significantly since 2005.



B. Model Run (b): Building Blocks as Designed

Model Run (b) simulated EPA's building block approach based on Wisconsin's current generation fleet. Building block 1 was modified to reflect identified limitations and includes a 3% improvement in heat rate at plants expected to stay in operation and built prior to 2005. Building block 2 changes included increased capacity factors to 70% for existing NGCC EGUs, and building blocks 3 and 4 were fully implemented as laid out in the proposal.

EGEAS modeling confirms the building blocks, which were developed independently of each other, do not work together to achieve the reductions desired by the EPA. When all four building blocks were implemented simultaneously, the total reduction in carbon by 2030 was 15.6%, which is far below Wisconsin's goal and demonstrates that EPA's proposed best system of emission reduction, on its face, does not function as a system.

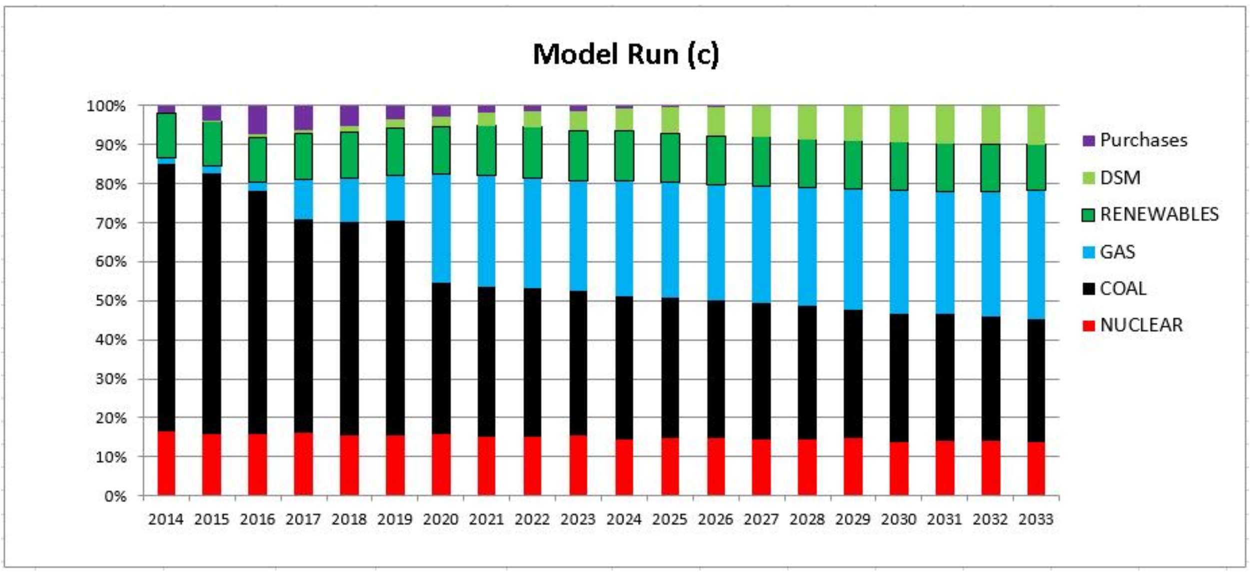


C. Model Run (c): Optimization Excluding Emissions from New NGCC Facilities

Model Run (c) allowed the electric system to run in an optimized manner to meet the calculated mass limit. It included the assumption that emissions from new units (specifically new NGCC units) are not counted toward the equivalent mass cap at any point before 2030. The average price of gas was assumed to be $4/MMBTU.

While this run met the overall mass cap for existing units, it excluded approximately 7.5 million tons of emissions from new NGCC plants which would presumably be regulated under EPA's proposed new source performance standard for power plants under section 111(b) until 2030. It also heavily relied on

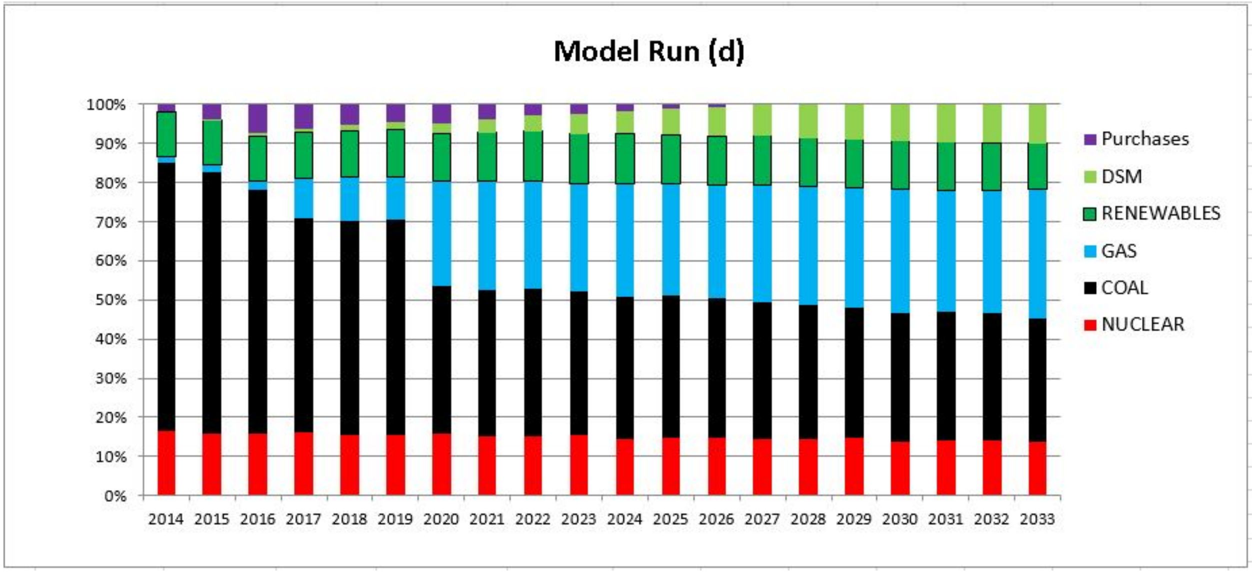
the *new* NGCC units, and tended to run the existing natural gas combined cycle units minimally, regardless of the relative emissions rates of the new and existing units.
The overall reductions in emissions for this case, assuming emissions from new NGCC units are excluded, was 34.4%. In reality, the reduction is closer to 19.3% when all emissions are considered. It was the lowest cost run, with a cost increase of $4.24 billion above the reference case (Model Run (a)). Because this run relied heavily on new NGCC plants, significant additional cost is expected for upgrading and building new gas supply infrastructure. It is questionable whether gas prices will remain at the current level if much of the country moves toward reliance on natural gas for base load electric generation. Any increase in the price of natural gas would also add significantly to this estimate. It is fair to say that this model significantly underestimates the overall cost of the proposal.



D. Model Run (d): Optimization Excluding Emissions from New NGCC Facilities with a $6/MMBTU Gas Price

This run held all parameters constant with Model Run (c) except for the price of natural gas. The U.S. Energy Information Administration projects gas prices of approximately $6/MMBTU, so this run was completed to show the impact of that increase on the system with the proposed rule in place. The cost of gas was raised from $4/MMBTU to $6/MMBTU in 2020 to model the price shock that is likely to occur at the beginning of the compliance period.

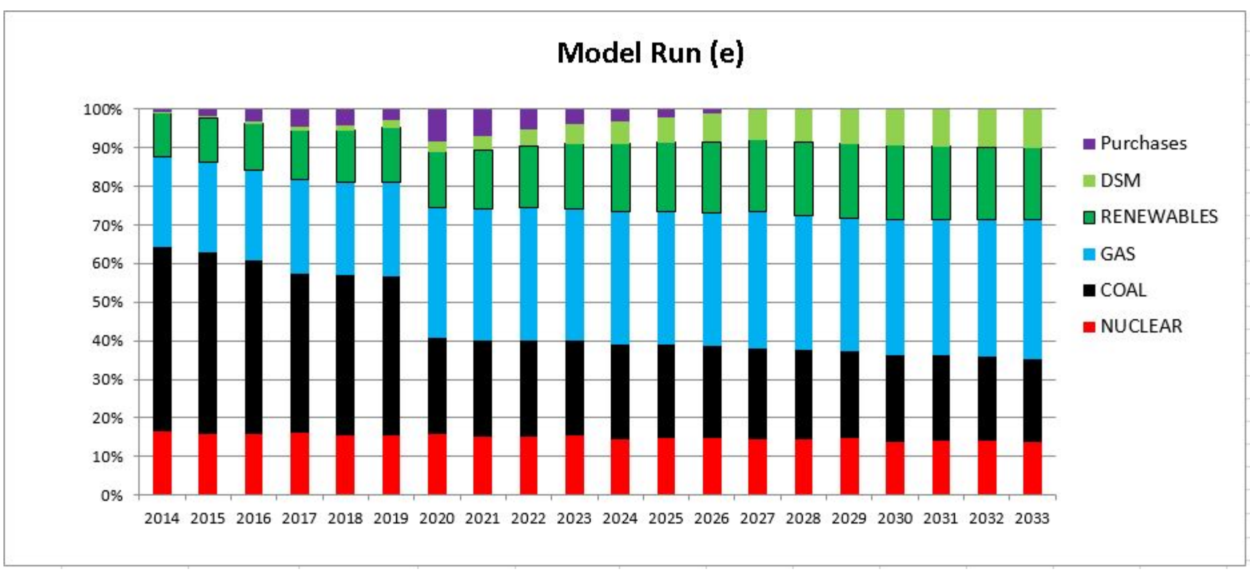
This scenario adds $7.47 billion in costs above the reference case, and $0.23 billion higher than Model Run (c), though it results in the same level of reductions as Model Run (c). The increased costs are attributable to the marginally higher gas prices, though the resulting generation mix did not change dramatically between this model run and the previous run.



E. <u>Model Run (e): Optimization Including Emissions from New NGCC Facilities</u>

This model had the same parameters as Model Run (c) above, but includes emissions from new NGCC facilities in the mass cap. This methodology would allow existing plants and new plants at the same emission level to compete in the energy market.

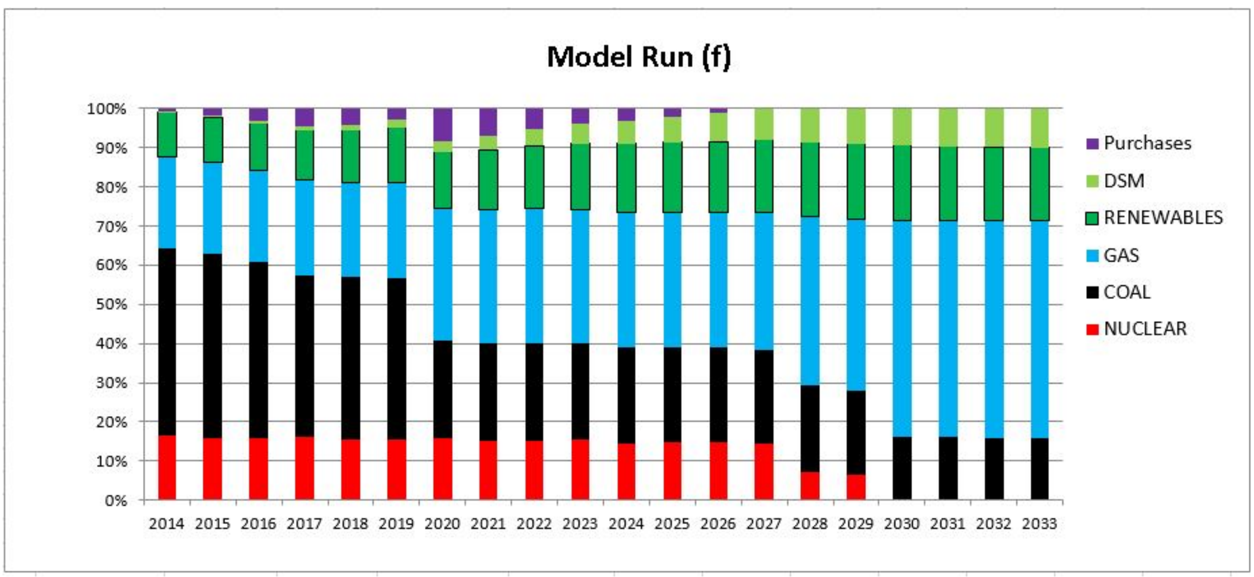
This resulted in an increase of $9.58 billion above the cost of the reference case, and reduced emissions by 35% total from the baseline. Because emissions from new NGCC plants were included in compliance, 35% is a true representation of the emissions reductions.



F. Model Run (f): Optimization Including Emissions from New NGCC Facilities and Accounting for Nuclear Retirements

This run had the same parameters as Model Run (e) above, and also accounted for the retirement of nuclear generation that will need to be replaced. The affected nuclear facilities supplying electricity to Wisconsin include two units at the Point Beach Facility and contracted portions of out-of-state units Prairie Island 1, Prairie Island 2, and Monticello. The licenses for these units will expire between 2030 and 2033. This model run assumed those units would no longer provide generation after their retirement date. EGEAS primarily replaced this lost nuclear generation with new NGCC facilities.

This was the highest cost scenario, with a total marginal cost increase of $13.44 billion from the reference case. The significant cost of this model run emphasizes why the future retirement of nuclear must be considered, particular because Wisconsin law does not currently allow construction of new nuclear facilities. A plan to replace lost nuclear generation must be considered long before the units go offline, and the cost of replacing that generation must be minimized.



3. The EGEAS runs demonstrate the necessity of staging rule requirements and allowing states to determine the appropriate schedule for interim requirements.

The modeling runs indicate that at least 1,800 to 2,400 megawatts (MW) of new NGCC capacity will have to be built by 2020 in order to meet the interim goals as currently proposed by EPA. This is a substantial undertaking that will have to go through environmental permitting processes and approval by PSCW. It is questionable whether the amount of new NGCC capacity can be permitted and built by 2020. It is estimated that such work would require five to seven years from start of the process to bringing the units online. If a state rule is not approved until 2019, the new NGCC units would not be available until 2024 to 2026 at the earliest. This modeling performed by the PSCW shows the importance of allowing states to determine the appropriate schedule for reducing carbon emissions.

4. EPA must allow states to replace lost nuclear capacity with existing coal generation resources.

Model run (f) showed that 6,600 MW of new NGCC may be required by 2030 to replace lost nuclear capacity due to license expiration. This may be up to an additional 4,200 MW beyond the new NGCC capacity needed for compliance if the nuclear generation remains online. This means that 55% of Wisconsin's generation will be from natural gas, and only 16% of the generation will come from coal-fired units. EPA cannot realistically expect natural gas infrastructure and Wisconsin utilities to be able to operate this much additional NGCC capacity. Therefore, EPA should allow states to offset lost nuclear generation with existing capacity, including existing coal-fired plants.

5. The modeling demonstrates building block 2, as proposed, is not cost-effective for electric generation.

A comparison of Model Run (b) with Model Run (c) shows that the EGEAS model selects installation of new NGCC capacity instead of operating existing NGCC capacity above a 15% capacity factor in 2020. This results in new NGCC units operating at over 80% capacity factor in comparison to existing NGCC units, which run below 20%, because emission from the new units do not count toward the goal and are, therefore, lower cost. Not only does this make it impossible for existing NGCC units to operate at a 70% capacity factor, as required by building block 2, but it also encourages construction of new NGCC units that would not otherwise be necessary to meet load. The market dynamics of the proposal significantly disadvantages existing NGCC facilities, regardless of their emissions level relative to a new NGCC facility.

6. Additional modeling will have to be conducted once a proposal is further refined in order to clearly understand potential cost impacts.

The results of this modeling exercise and discussion illustrate the wide range of cost due only to the generation fleet that could result from the proposed CO_2 rule. This exercise also highlights that EPA must re-propose the rule for additional review, analysis and comment after refining requirements. The rule as proposed contains ambiguity that prevents the PSCW from accurately assessing the total cost impact on Wisconsin citizens. States must be allowed to fully understand the cost impacts based on clearly defined parameters before the rule is finalized.

7. The modeling analysis indicates that significantly more analysis by the EPA must be done to assess the impacts on electric reliability and costs for upgraded electric and gas infrastructure.

The EGEAS modeling shows that new NGCC will be extensively utilized in any compliance plan, especially in the case where existing clean nuclear capacity is retired at license expiration. This modeling, however, does not assess feasible schedules for installing this capacity or necessary work to the natural gas infrastructure. In addition, the modeling does not assess the electric reliability implications of retiring coal capacity or turning down coal from 60% to potentially less than 20% of Wisconsin's energy needs by 2030. Nor does the model evaluate how much of the expense to ratepayers is stranded costs for plants that are already built and are currently being paid for. Also excluded is the cost of additional infrastructure installation costs. Further work needs to be done in evaluating these issues.

Wisconsin's Comments on EPA's Proposed Clean Power Plan
November 30, 2014
Docket ID No. EPA-HQ-OAR-2013-0602

Additional Attachments Referenced in Comments

1. State of Wisconsin comments to Administrator McCarthy on EPA's development of CO_2 regulations for existing power plants, December 13, 2013.

2. Perspectives of 18 states on greenhouse gas emission performance standards for existing sources under sec. 111(d) of the Clean Air Act (state attorneys general white paper).

3. Letter to President Obama from 15 states expressing concerns about U.S. EPA's proposal for reducing carbon dioxide at existing power plants, September 9, 2014.

State of Wisconsin \ DEPARTMENT OF NATURAL RESOURCES

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December 13, 2013

Ms. Gina McCarthy, Administrator
US Environmental Protection Agency
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460

RE: Comments regarding development of carbon dioxide regulations for existing power plants.

Administrator McCarthy:

The State of Wisconsin appreciates the opportunity to provide comments regarding development of carbon dioxide (CO_2) regulations for existing power plants under section 111(d) of the Clean Air Act. In September 2013, the U. S. EPA (EPA) issued a series of questions to states for response. This letter and attachment responds to those questions and relays major concerns that have been identified through review of the issues and stakeholder engagement.

To begin, we must emphasize that the technical comments set forth below should not be interpreted as the State of Wisconsin's endorsement of this initiative. Given that EPA has not yet provided a rule proposal for comment, these comments are necessarily preliminary in nature, and we reserve the right to revise these comments and the related underlying assumptions in response to any specific proposal. Furthermore, this response does not waive any future legal claims that the state may have regarding the promulgation or enforcement of the regulations.

We note that there are significant legal issues regarding EPA's authority to regulate CO_2 emissions from existing power plants and important policy concerns regarding this regulation. As noted in a November 4, 2013 letter from Governor Walker to EPA Administrator Gina McCarthy, Wisconsin derives over half of its electricity from coal-fired generation, and a number of coal units have already shut down. This approach risks continued access to Wisconsin's most reliable energy source and our ability to provide affordable energy to the citizens of Wisconsin.

The Wisconsin Department of Natural Resources (WDNR) worked with the Public Service Commission of Wisconsin (PSCW) and the State Energy Office (SEO) to evaluate issues related to developing CO_2 requirements for power plants. The WDNR also received input from seven electric utilities, two industrial groups, a prominent environmental group, a citizens' utility group, a statewide business association and an academic energy policy researcher. Based on this work, we have identified the following issues and concerns.

- **CO_2 is not like other air emissions.** There are no readily available back-end control technologies that reduce emissions of CO_2 from power plants. Regulation of CO_2 emissions therefore requires a different type of regulatory approach than that applied to other air emissions. Any regulation of CO_2 emissions must consider the specific situation of each utility, including the size, age, and debt load of its fleet, and must allow utilities to comply via off-site programs to reduce CO_2 emissions (e.g., via renewable electricity and energy efficiency).

- **Cost is an important concern for the State of Wisconsin.** EPA must ensure that costs incurred under any requirement for the "best system of emission reduction" (BSER) are minimized by providing states maximum flexibility in determining BSER and allowing maximum flexibility in compliance options. States must be able to set compliance deadlines that allow utilities to pay off existing debt on their power plants and pollution control equipment. Since 2000, Wisconsin utilities have invested over 3.2 billion dollars in air pollution control equipment and efficiency upgrades for existing power plants. Setting fixed compliance dates could strand this debt and make the installation of new, cleaner replacement generation more costly.

- **Existing state programs that reduce CO_2 emissions.** Wisconsin has had a state Renewable Portfolio Standard (RPS) since 1999 and a very effective, utility-funded energy efficiency program called Focus on Energy (Focus) since 2002. We estimate that the RPS and Focus programs have resulted in avoided CO_2 emissions equivalent to roughly 10 percent and 7 percent of total 2005 emissions, respectively. The RPS and Focus programs have significant tracking and verification systems in place and should qualify as compliance mechanisms for any potential CO_2 regulation affecting existing power plants.

- **Credit for CO_2 reductions already achieved.** Wisconsin utilities have already invested significant money to build new, more efficient power plants and retire older units. Wisconsin utilities have invested over 4.5 billion dollars for 4,200 megawatts (MW) of new coal and natural gas generation since 2000. In addition, over 2.3 billion dollars is invested in approximately 1,100 MW of renewable electricity for meeting the state RPS requirement. Wisconsin ratepayers have also contributed over 469 million dollars to the Focus program and other efficiency efforts since 2000. Since 2005, as a result of these combined actions, the power plant fleet heat rate (efficiency) has improved by approximately 9 percent and overall CO_2 emissions have been reduced by approximately 16 percent. Wisconsin's early actions and investments should be credited under a CO_2 regulation for power plants. In order to credit these and other early CO_2 reduction measures, states should be able to credit actions back to 2000.

- **Biomass energy.** We submit comments and suggestions on two issues related to biomass energy: 1) BSER performance standards for power plants should not apply to any portion of biomass co-fired with fossil fuel, and 2) biomass should be considered a carbon neutral energy source and be creditable for demonstrating compliance with a fossil fuel BSER performance standard. Biomass energy qualifies as a renewable fuel under the state RPS, and the state follows state-certified sustainable forestry practices to ensure the carbon-neutrality of biomass fuels. This sustainable forestry program is successful and could serve as a model for the country. Wisconsin utilities have already installed approximately 132 MW of woody biomass-fired capacity and are co-firing waste wood and paper in several other units. All of these investments should count towards compliance with any regulation of CO_2 emissions.

While this letter highlights our major concerns and recommendations, an attachment is provided to this letter which explains our high-level concerns along with other identified concerns in greater detail and describes existing state programs that should be relevant under the development of CO_2 regulations for existing power plants.

In conclusion, after lengthy discussions between Wisconsin state offices and with our stakeholders, and assuming EPA decides to move forward with the development of BSER guidelines under section 111(d) of the Clean Air Act, the State of Wisconsin recommends a regulatory structure that allows states to balance carbon reductions with minimal cost to consumers.

Sincerely,

P. L. Montgomery

Phil Montgomery
Chairperson
Wisconsin PSC

Eric Callisto
Commissioner
Wisconsin PSC

Ellen E. Nowak

Ellen Nowak
Commissioner
Wisconsin PSC

Cathy Stepp

Cathy Stepp
Secretary
Wisconsin DNR

Cc:
Bob Norcross, Administrator, Division of Gas and Energy, PSCW
Pat Stevens, Administrator, Division of Air, Waste and R&R

Attachment: Discussion of Major Issues and Response to EPA Questions Related to Developing a BSER CO_2 Performance Standard for Existing Power Plants

Attachment

Discussion of Major Issues Related to Developing a CO_2 BSER Performance Standard for Existing Power Plants.

This attachment provides additional information related to developing CO_2 performance standards for existing power plants. The attachment is organized to be responsive to four questions posed by the U.S. Environmental Protection Agency (EPA).

For further information regarding this attachment, please contact Bart Sponseller at (608) 264-8537 or Bart.Sponseller@Wisconsin.gov.

Section 1. Response to EPA Question 1

EPA Question 1. What is state and stakeholder experience with programs that reduce CO_2 emissions in the electric power sector?

- *What actions are states, utilities, and power plants taking today?*
- *How are these emissions reductions measured and verified?*
- *How are interstate effects accounted for?*

A. Summary of Recommendations - Question 1

The State of Wisconsin has three overall recommendations in responding to EPA's question related to existing programs that reduce CO_2 emissions:

1) Wisconsin's Renewable Portfolio Standard (RPS) and utility-funded energy efficiency and renewable electricity program (Focus on Energy) must be allowed to count towards compliance with any electric utility CO_2 regulation, including both past and future measures;
2) Voluntary programs that reduce CO_2 emissions from the power sector and that have systems to verify avoided generation and/or emissions should also qualify; and
3) Renewable electricity generated out-of-state and owned or contracted for by Wisconsin utilities should be credited to the state of Wisconsin and Wisconsin utilities.

B. Extended Discussion – Question 1

Overall CO_2 emissions from power plants in Wisconsin decreased 16% from 2005 to 2012,[1] with a particularly sharp decline between 2011 and 2012. The overall trend of reduced CO_2 emissions from power plants is attributable to a number of different factors, including but not limited to:

1) **Improved heat rates** of the Wisconsin generation fleet due to efficiency upgrades, retirements of older, inefficient capacity, and construction of new, more efficient capacity. Overall heat rates decreased by 9% from 2005[2] to 2012, and CO_2 emission rates at Wisconsin power plants have declined 10% over this time period;
2) **Wisconsin's Focus on Energy program**, which is funded by utilities and provides incentives for installation of energy efficiency and renewable energy measures, and which has reduced CO_2 emissions by approximately 7% from 2005 levels;
3) **Wisconsin's state Renewable Portfolio Standard (RPS)**, which requires 10% renewable generation by 2015, and which has reduced CO_2 emissions by approximately 10% compared to 2005 levels; and
4) **A number of state initiatives and voluntary programs**, although the magnitude of the emission reductions achieved by these programs is generally smaller than that from the RPS and Focus on Energy programs.

This response is organized around these four types of CO_2 reduction programs. We describe these measures, along with the structure of these programs and estimates of avoided emissions, in detail below. It is notable that the RPS and Focus on Energy programs have extensive systems in place to measure and verify renewable electricity generation, avoided electricity generation and/or CO_2 emissions reductions attributable to the programs. At the end of this discussion in Item 5, we address how these measures are relevant under section 111(d) and make recommendations to EPA about how a program could be structured to allow these compliance mechanisms.

1) <u>Heat Rate Improvements at Facilities</u>

Heat rates at EGUs in Wisconsin have been steadily improving over the time period analyzed (1997-2012), as shown in Figure 1. These improvements have been driven by the utilities themselves and by the economics involved in producing electrical power. Figure 1a shows heat rates for coal and natural gas-fired power plants in the state, along with the overall average for all power plants. During this time period, heat rates decreased on average 0.5% per year at coal-fired plants and 2.9% per year at natural gas-fired plants, for combined reductions of 4.0% and

[1] Based on data reported by the generators to U.S. EPA and downloaded from the Air Markets Program Data website: http://ampd.epa.gov/ampd/.

[2] Throughout this discussion, we compare emission reductions to 2005 emissions levels because this was the year that power plant emissions peaked in the state.

21%[3] for coal- and natural gas-fired plants, respectively, from 2005 to 2012. Overall heat rates decreased by 9% and the CO_2 emission rates declined 10% over this time period (Figure 1b). These heat rate reductions occurred because of a combination of closure of older, inefficient units, construction and operation of newer, more efficient units, and adjustments made on-site to improve operation of existing units. See Table 1 for a list of plant closures and openings. The CO_2 emissions illustrated below were reported to EPA for compliance with other air quality programs, so the verification of these emissions already lies with EPA. Looking into the future, a number of additional coal unit closures are planned, as well as several conversions of coal-fired units to natural gas energy (Table 1). These actions will contribute to additional improvements in utility fleet heat rates in the future.

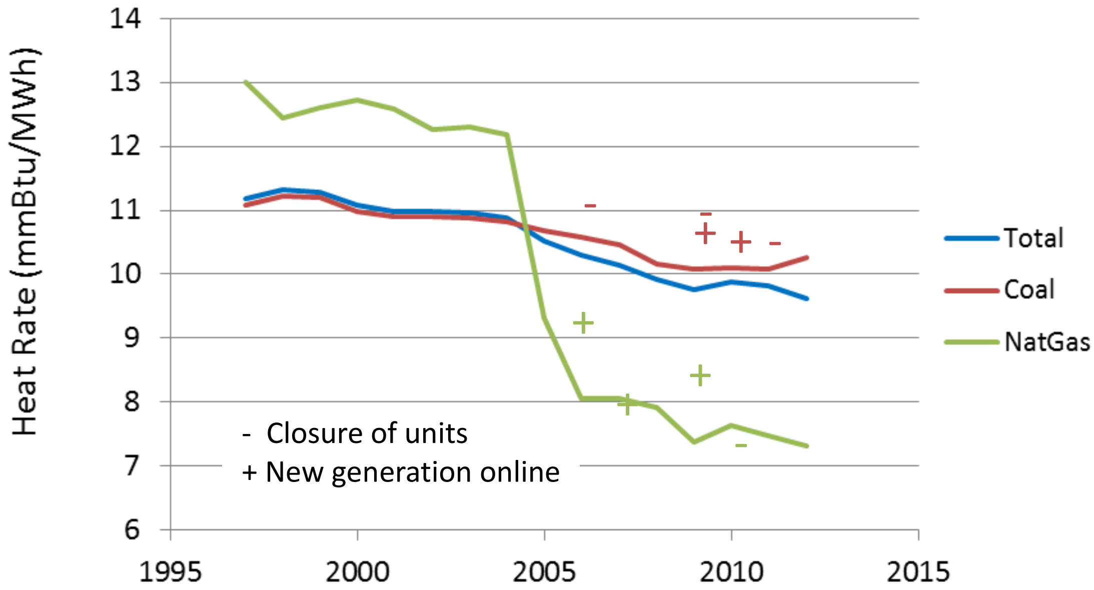
Table 1. List of power plants in Wisconsin that retired, began operations or switched fuels since 1997 and planned future changes.

Facility	Capacity (MW)	Units	Type of facility and date changed
Plant Retirements			
Alma	63	1-3	Coal, retired 2005
Manitowoc	46	5-7	Coal, retired 2010
Port Washington	322	1-4	Coal, retired 2005
Pulliam	53	3-4	Coal, retired 2008
Rock River	150	1-2	Natural gas, retired 2009
New Generation Capacity			
Elm Road	1234	1-2	Coal, operational 2009 & 2010
Fox Energy	310	1-2	N. gas combined cycle, operational 2005/2006
Port Washington	1090	11, 12, 21, 22	N. gas combined cycle, operational 2005/2008
Riverside Energy Center	600	1-2	N. gas combined cycle, operational 2005
West Campus Cogeneration	150	1-2	N. gas combined cycle, operational 2005
Weston	519	4	Coal, operational 2008
Fuel Switching			
DTE Stoneman	50	1-2	Former coal-fired plant, converted to firing wood in 2010
Planned Future Actions			
Retirements of coal units	717	9 total	Planned for 2015 and 2016
Conversion (coal→n. gas)	297	5 total	Planned for 2015 and 2016

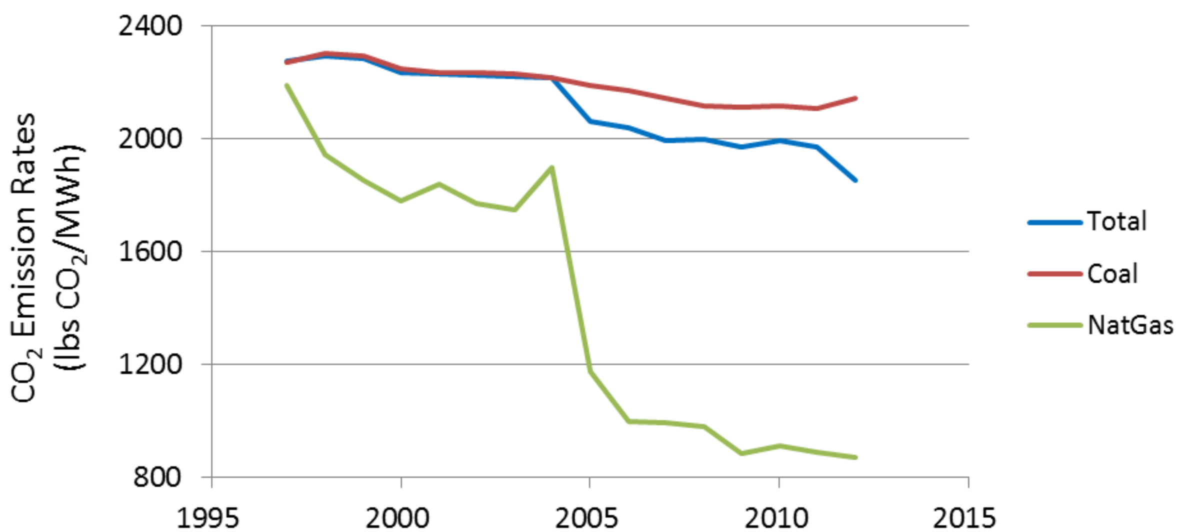
[3] The emission rate decrease is 40% for the years 2004-2012 because of the new combined cycle units installed in 2005.

Figures 1a and 1b. Heat rates (a) and CO_2 emission rates (b) for coal-fired, natural gas-fired, and average fleet power plants in Wisconsin.

a) Heat Rates



b) Emission Rates



Note: The heat rates and CO_2 emission rates are derived from CO_2 emissions, fuel consumption (mmbtu) and generation (MWh) data obtained from EPA's Clean Air Markets Division, http://ampd.epa.gov/ampd/. Years when units closed or began generation are marked with "-" and "+", respectively.

2) Focus on Energy Program

Program Description Since 2002, Wisconsin has operated a very effective statewide energy efficiency and renewable energy program, Focus on Energy. The program seeks to reduce energy use primarily by providing financial incentives for customers to purchase products and services that achieve energy efficiency or to install renewable generation. Wisconsin's electric and gas utilities (including investor-owned utilities, municipal utilities, and retail electric cooperatives) collectively fund Focus on Energy and recover their contributions from their customers through rates. The Focus on Energy program is designed and run by an independent third-party administrator, under the oversight of the Public Service Commission of Wisconsin (PSCW).

The PSCW, with guidance from State statute, sets goals for Focus on Energy that, in addition to saving energy, include avoiding "adverse environmental impacts from the use of energy." To help measure achievement of its environmental goal, Focus on Energy tracks the emissions reductions associated with the energy savings it has achieved, including reductions in CO_2, NO_x, SO_2 and mercury. Focus on Energy also estimates the monetary value of those emissions reductions and includes those estimates in its calculations of program cost-effectiveness.

Measurement and Verification The PSCW contracts for independent, third-party evaluation of Focus on Energy. Using a combination of methods that include participant surveys, engineering reviews, and on-site metering of energy use, independent evaluators seek to estimate the amount of energy savings achieved in connection with Focus on Energy to a high degree of statistical certainty. (For example, evaluation activities during the 2011-2014 contract period are designed to estimate savings for all Focus activities at a 90% confidence level with ±10 percent precision. This "90/10" goal is an industry standard for energy efficiency evaluation.)

These measurements result in two energy savings estimates. "Gross" energy savings include all savings associated with program activities. "Net" (or "additional") savings only include those savings that evaluators conclude were directly attributable to the influence of Focus on Energy.

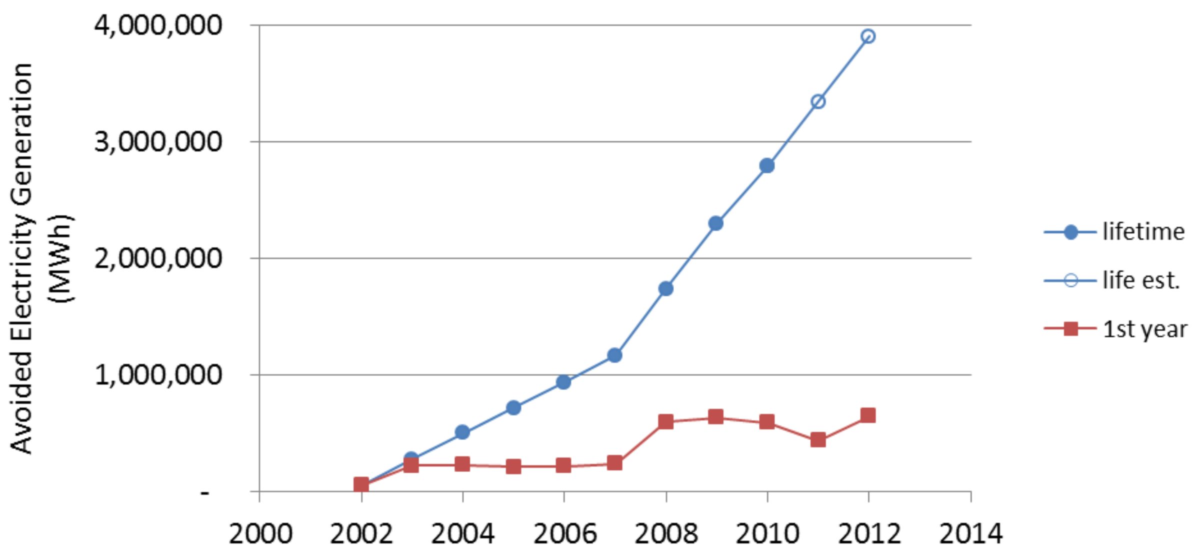
Avoided Generation and Emissions To estimate total emissions reductions achieved by Focus on Energy, net savings are multiplied by emissions factors that are calculated for each measured pollutant, including CO_2. Program evaluation staff have calculated emissions factors by 1) using EPA's Acid Rain Hourly Emissions Data to identify emissions for Wisconsin power plants operating on the margin; 2) averaging emissions for all marginal plants in each hour of the year; 3) calculating a weighted average of emissions across all hours, using load shapes developed specifically for Focus programs to take into account the timing of savings; and 4) updating emissions factors on an annual basis by using a time-series regression equation. This method is designed to align Focus methods with the World Resource Institute's Greenhouse Gas Protocol Initiative and provide the most nuanced possible estimate of actual emissions reductions within the state.

We believe the most relevant measure of avoided CO_2 emissions for a program to regulate CO_2 emissions from existing power plants would be on a "lifetime" basis, where "lifetime" includes the cumulative emissions that were avoided in a given year by all measures installed in that and previous years that are still in place. For example, if a type of measure had an average lifetime of 9 years, the lifetime avoided emissions for 2012 would include those from measures installed in years 2004 to 2012. These values were calculated by the PSCW through 2010. Values for 2011 and 2012 are estimates, but actual values could be calculated if time permitted. Figure 2 also shows the avoided generation and emissions for the first year the measures were installed.

We estimated that the lifetime avoided gross electricity generation for the Focus on Energy program was 3.9 million MWh for 2012 (Figure 2), and the lifetime avoided "net" electricity generation was 2.6 million MWh for the same year (not shown). This avoided generation corresponds to lifetime avoided emissions of 3.2 million metric tonnes of CO_2 (Figure 3), or emissions reductions of 7% of 2005 peak emissions.

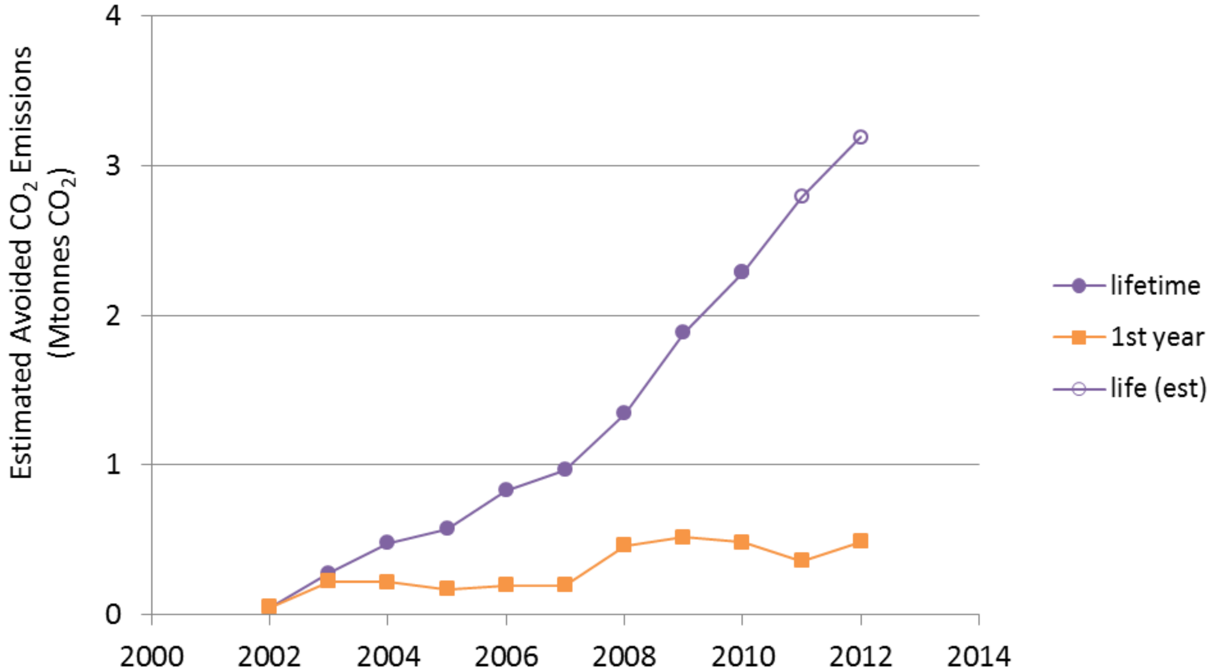
As demonstrated, Wisconsin has many measures currently in place that should be allowed to count towards compliance with this regulation.

Figure 2. Estimated Gross Electricity Generation Avoided due to the Focus on Energy Program.



Note: Avoided generation is shown for the first year the efficiency measures were in place and for the cumulative measures in place in a given year ("lifetime"). The open symbols were estimated using average lifetimes of measures.

Figure 3. Estimated CO_2 Emissions Avoided due to Gross Electricity Savings Under the Focus on Energy Program.



Notes:

1) Emissions were estimated using an emission factor developed by the Focus on Energy program which assumed the measures displaced marginal electricity production. Units are million metric tonnes.
3) Data shown are for emissions avoided due to measures enacted that year ("1st year") and for cumulative avoided emissions due to all measures in place that year ("lifetime"). The open symbols with solid lines were estimated using average lifetimes of measures.

3) <u>State Renewable Portfolio Standard</u>[4]

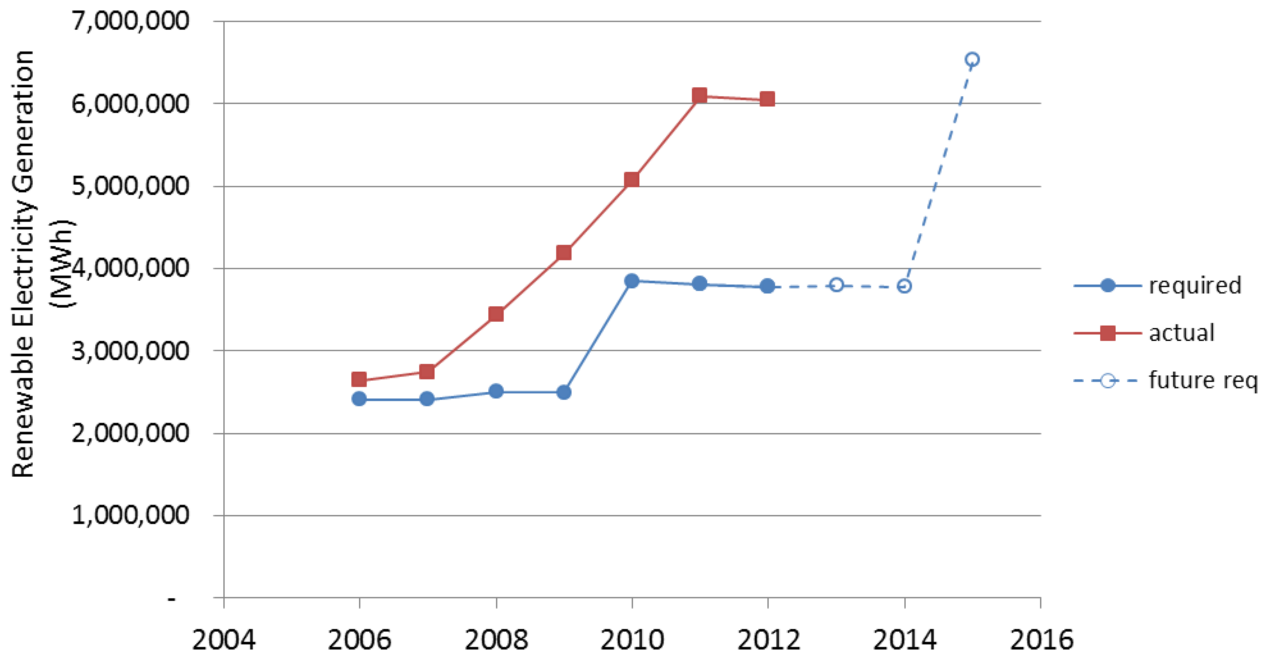
Program Description Wisconsin's Renewable Portfolio Standard (RPS) has a statewide goal of 10 percent of all electric energy consumed in the state being renewable energy by the year 2015. The RPS was established by Wisconsin Statute § 196.378 and applies to all electric providers that serve retail customers in Wisconsin.[5] The RPS requires Wisconsin retail electric providers to annually report renewable energy sales and activity to the Public Service Commission.

For each calendar year (CY) from 2006 through 2009, electric providers were required to meet a baseline percentage equal to the average of the electric provider's renewable energy percentage for the years 2001 through 2003. Beginning in CY 2010, electric providers were required to achieve a renewable energy percentage at 2.0 percent above their respective baselines. For CY 2012 through 2014, electric providers are required to maintain a renewable energy percentage at

[4] The information in this section was adapted from the Public Service Commission of Wisconsin (PSCW) Memorandum on 2012 Renewable Portfolio Standard compliance, with the exception of the estimates of avoided CO_2 emissions, which were conducted for these comments.
[5] These electric providers include all investor-owned utilities, municipal utilities, and electric cooperatives that serve residential and business customers in the state.

2.0 percent above their baselines. In order to comply with the RPS in 2015 and thereafter, electric providers will need to meet and sustain a level that is 6.0 percent above their respective baselines. These requirements are shown graphically in Figure 4.

Figure 4. Wisconsin Renewable Portfolio Standards and Actual Renewable Generation.



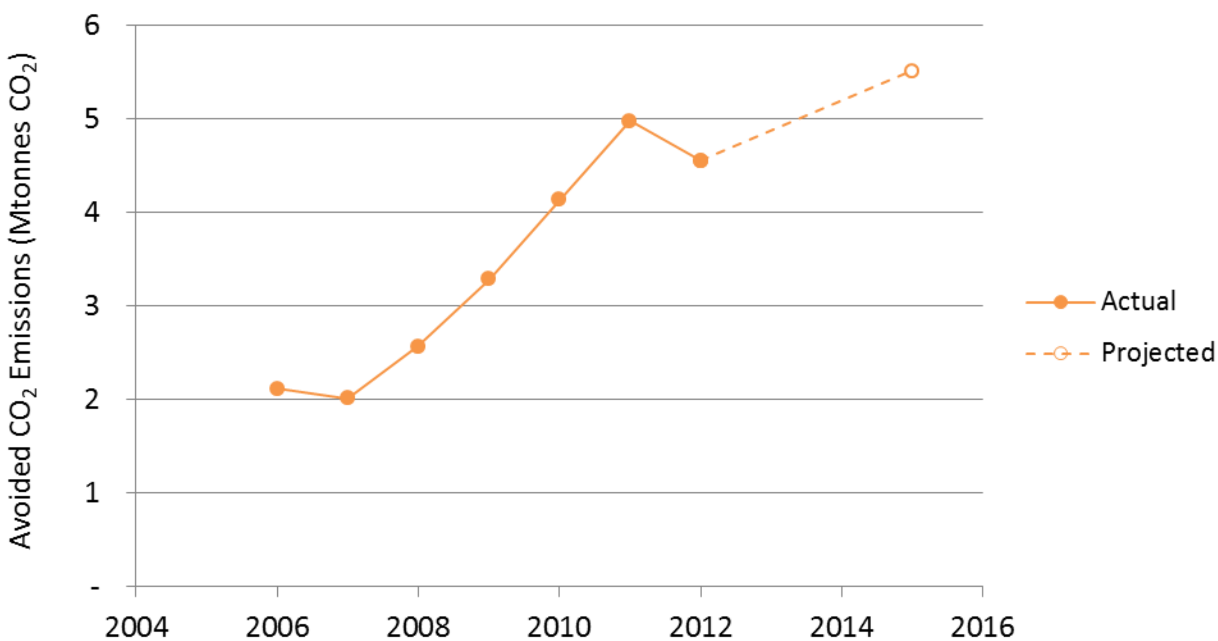
Note: The requirements shown for future years are based on aggregated electric provider requirements as opposed to the overall 10% statewide goal. This data does not include renewable electricity sold through individual utility green pricing programs.

Electric providers achieve compliance with their RPS requirements by selling electricity to their retail customers from renewable resources and by using Renewable Resource Credits (RRC) created in previous years. An electric provider creates bankable RRCs when it sells electricity from renewable resources in excess of that year's RPS requirement.

Measurement and Verification Electric providers use the Midwest Renewable Energy Tracking System (M-RETS), an electronic renewable energy tracking database, to track their renewable energy and to demonstrate RPS compliance. The PSCW tracks renewable energy using M-RETS and electric provider data. In order to avoid double-counting of renewable electricity, M-RETS requires generators to report all of their generation to M-RETS and to attest that the unit is not registered in any other tracking system. M-RETS further verifies all reported data and has established accounting procedures to prevent internal double-counting as well as double-counting between different tracking systems. The PSCW does not currently track CO_2 emissions avoided by the Wisconsin RPS or voluntary renewable energy. For construction cases before the Commission, PSCW staff will use pertinent CO_2 estimates provided by utilities for modeling assumptions.

Generation and Avoided Emissions All electric providers have met their requirements through CY 2012 and, due to the RPS, have increased the statewide percentage of electric retail sales from renewables from 3.78 percent in CY 2006 to 8.79 percent in 2012. This represents an increase of renewable energy from 2,664,228 Megawatt-hours (MWh) in CY 2006 to 6,049,427 MWh in CY 2012 (Figure 4).[6] In order to achieve RPS requirements in 2015, Wisconsin electric providers are entering into new purchase power agreements with independent power producers that own renewable facilities – primarily wind and biogas facilities. In a joint venture with a Wisconsin paper company, one electric provider recently put into service the 50 MW Rothschild Biomass Cogeneration Plant, which will burn wood waste in order to generate electricity for the electric grid and heat for the paper company's industrial processes. We estimated the CO_2 emissions avoided by the RPS program resulted in approximately a 10% emissions reduction from 2005.

Figure 5. Estimated CO_2 Emissions Avoided to the Wisconsin RPS.



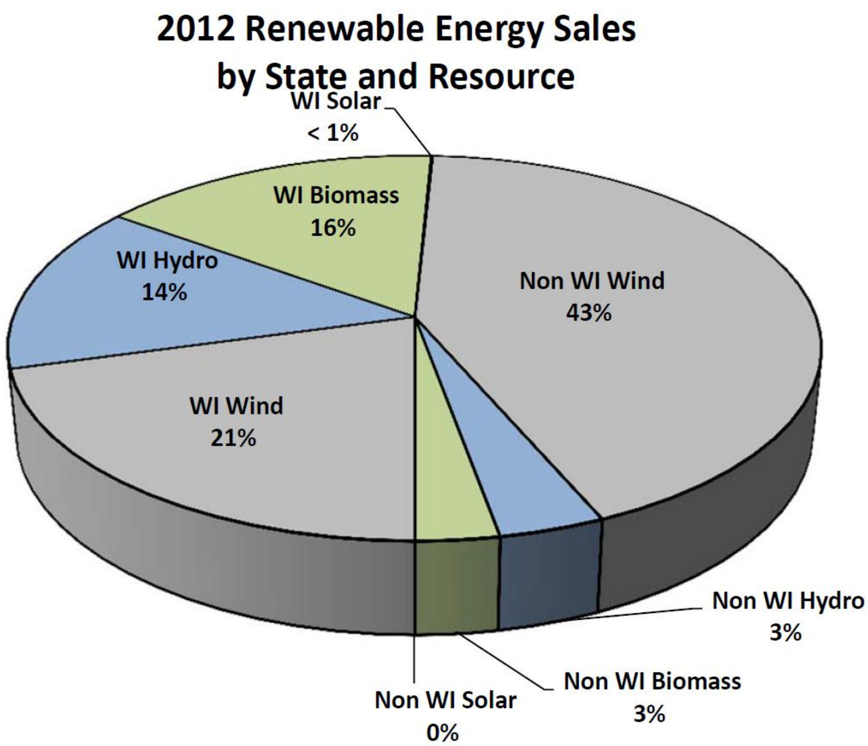
Note: The open symbol and dotted line shows estimated emissions that would be avoided if each utility meets its requirement for 2015. Units are in million metric tonnes. The data does not include renewable electricity sold through individual utility green pricing programs.

Out-of-State Renewables It is essential that Wisconsin be able to count the out-of-state renewables generation that was paid for by Wisconsin utilities for compliance with the state RPS for compliance with a § 111(d) regulation. The Wisconsin RPS allows electric providers to procure renewable energy that is generated either in-state or out-of-state. In practice, about half of the renewable electricity used for compliance with the state RPS is generated in-state (Figure 6). The remainder primarily is generated in Minnesota, Iowa or Michigan. All renewable generation that is eligible for the Wisconsin RPS must come from a facility that is providing energy to Wisconsin retail customers. This means that the Wisconsin electric provider must

[6] The reduction in renewable generation in 2012 was due to lower production of hydroelectric power owing to the 2012 drought.

either own the facility or have a purchase power agreement with an independent power producer that owns the facility. The Wisconsin RPS considers in-state and out-of-state renewable generation, as well as other states RPS programs, by utilizing the MRETS tracking system described above.

Figure 6. State Origin of Renewable Electricity Sold in Wisconsin in 2012.



Note: This data includes renewable electricity used for compliance with the state RPS and sold through individual utility green pricing programs.

4) Voluntary Programs and State Initiatives to Reduce CO_2 Emissions

Voluntary Utility Energy Efficiency Programs In addition to the statutorily prescribed energy efficiency and emission reduction programs, a number of additional, utility-specific energy savings and conservation activities that are overseen by the PSCW exist. In the past, verification of the avoided generation associated with these activities was less rigorous than that for the Focus on Energy program, and the magnitude of the avoided emissions averaged around 10% of that from the Focus on Energy program. However, the PSCW is actively working with the utilities to improve verification.

Green Pricing of Renewable Electricity In addition to renewable electricity used for compliance with the state RPS, Wisconsin electric providers offer opt-in voluntary programs, known as "green pricing programs," to their retail customers. These programs use renewable resources separate from what is required by the RPS law. These programs often include utility-scale renewable energy projects and/or distributed generation owned by the retail customer. These programs have averaged around 7% the generation of that used under the RPS program. All electric providers that have green pricing programs track the renewable energy in M-RETS, with the exception of one small electric cooperative.

Other Programs The Wisconsin State Energy Office (WSEO) was awarded an Energy Efficiency and Conservation Block Grant from the U.S. Department of Energy as part of the American Recovery & Reinvestment Act. This award funded three different projects focused on retrofits, lighting and education. WSEO is now working to close out the program and is working on compiling and reporting data on this grant. Avoided generation from this grant is preliminarily estimated to be roughly 1% of that from the Focus on Energy program.

The State of Wisconsin also has programs in place to reduce the energy consumption of state-owned facilities and to increase the amount of renewable electricity used by state facilities. Additionally, a number of smaller programs focus on, for example, increasing energy efficiency at craft breweries, providing technical assistance to municipalities, schools and others with energy efficiency projects, and removing barriers to industrial energy efficiency and combined heat and power projects.

5) Relevance of Programs Under Section 111(d) and Recommendations to EPA

The emissions reductions from Wisconsin's Renewable Portfolio Standard and the Focus on Energy program must be credited to the state as a compliance mechanism for any regulation EPA develops. These programs have achieved and will continue to achieve significant reductions in CO_2 emissions, at a cost to Wisconsin's ratepayers, and both have extensive systems in place to measure and verify avoided generation and/or avoided emissions. Both programs should readily fit under an existing source regulation, and reductions already achieved should be credited as well as future reductions. However, given the statewide structure of the Focus on Energy program (in which utilities fund a centralized program to promote energy efficiency and renewable electricity), EPA must ensure that its regulation allows such programs to count towards compliance. Voluntary and state-run programs whose emissions reductions can be verified should also qualify for compliance.

It is also essential that EPA allow renewable electricity that was generated out-of-state and was owned by or contracted for by Wisconsin utilities to be used for compliance with Wisconsin's obligations under this rule. The Wisconsin utilities and ratepayers paid for this generation, which should be credited to them. More generally, EPA should write into their guidelines that renewable electricity be credited to the utility (or state) that owns or contracts for that generation. This would ensure equity between states in their handling of renewable electricity and ensure that no renewable generation is double-counted. It also allows for more cost-effective compliance with the regulations.

Section 2. Response to EPA Questions 2, 3 & 4

EPA Question 2. How should EPA set the performance standard for state plans? Options include considering: (a) onsite actions, (b) shifts in generation, (c) offsite actions.

- *Which approaches should be included? Source- or system-based?*
- *Connection between measures used for compliance and those used in setting the limit?*
- *What should be the form and specificity of the performance level(s) in EPA guidelines?*
- *When can emission reductions from existing power plants be achieved?*
- *How should a facility's "remaining useful life" be considered?*

EPA Question 3. What requirements should state plans meet in developing their plans? What flexibilities should EPA provide.

EPA Question 4. What can EPA do to facilitate state plan development and implementation?

Because the responses to EPA's Questions 2 through 4 are closely related, we have combined the responses below. For ease of reference, we have provided a summary of our recommendations followed by an in-depth discussion.

A. Summary of Recommendations - Questions 2, 3 & 4

1) SIP Process

SIP Deadlines – EPA needs to provide at least 3 years from the time the BSER guidelines are finalized until SIPs must be submitted. EPA should also allow states to obtain additional time for SIP submittal based on need.

SIP Flexibility – EPA should allow states to comply with BSER through programmatic alternatives that are equivalent to a BSER requirement for the power plants.

SIP Coordination – EPA should allow a SIP process where states can collaborate across state-lines and with the independent operator systems (ISO) in both formulating BSER performance standards and in demonstrating compliance.

2) Credit for Reductions Already Achieved

Investments and Reductions - Wisconsin utilities have made significant investments and achieved significant CO_2 reductions since 2000. Refer to Item 2 of the extended discussion for details.

3) Source-based vs. System-based BSER

BSER Guidelines – Section 111(d) of the Clean Air Act mandates that EPA set enforceable guidelines and that states have the responsibility for setting the BSER performance standard.

Complexity – Wisconsin believes that source-based standards are more straightforward. System-based performance standards will be resource intensive to determine and may create in-equities between utility systems.

Regulatory Precedent – Source-based performance standards are consistent with past power plant regulations formulated in meeting Clean Air Act requirements. EPA has not previously promulgated a regulation, including for regulations under section 111(d), based on system-based emission limitations.

System Ownership and Operation – Establishing system-based performance standard assumes actions for portions of the electric system that is under different ownership or control from that of the operators of the power plants regulated under section 111(d).

Renewable Energy – EPA should not include use of renewable energy in setting a performance limit. Renewable energy is not equally available to all utilities and may have negative impacts on system operations if not integrated over the appropriate timeframe.

Assumed Electricity Loads – EPA should not build assumptions about future electricity loads into a performance limit.

Utilization of Existing Fossil Fuel Capacity – A performance standard needs to allow full use of existing fossil fuel-fired capacity.

4) Factors in Setting a Performance Standard

Source Categories - States should have the flexibility to differentiate BSER requirements based on the type of combustion turbine or boiler, type of fuel (including whether bituminous or subbituminous coal), cost-effectiveness, the power plant size and age, and its remaining debt.

5) Form of a BSER Performance Standard

Mass vs. Emission Rate - States should be allowed to structure the BSER as either a mass or emission rate requirement.

Utilization of Existing Fossil Fuel Capacity – A performance standard needs to allow full use of existing fossil fuel-fired capacity.

6) Compliance Timeframes

CAA Requirements – The CAA does not specify a compliance timeframe under section 111(d). Section 111(d) directs EPA to follow section 110 SIP process. Section 110 does not require a compliance timeframe for a non-NAAQS pollutant such as CO_2.

State Flexibility – The states need to be afforded the flexibility to determine reasonable compliance dates based on achievability and on a timeframe that avoids stranding existing plant debt.

Compliance Timeframes – The states should be afforded a minimum of 7 years from finalization of BSER guidelines for compliance with a BSER requirement. States should also be allowed to grant additional time as needed to address remaining plant life or investments or if an extension will yield a better long-term outcome. Further, states should be able to grant additional time on a utility system basis.

Factors considered in proposing this compliance timeframe include:

- Significant plant upgrades can take 5 or more years to completion.
- New combined cycle plants in Wisconsin require roughly 7 years for completion.
- Time must be provided to implement renewable energy in a manner that avoids negative impacts to the generation system.
- Utilities need time to pay off existing debt on coal-fired generation. Major investments are amortized over 20 to 30 year periods, thus investments made since 2000 will still need to be paid off over the next 10 to 20 years.

7) **Compliance Flexibility**

Credit for Achieved CO_2 Reductions – EPA should allow States to count CO_2 reductions from utility actions back to 2000 in demonstrating compliance with BSER (refer to Item 2 in the extended discussion for details).

Utility System Compliance Measures – Utilities should be able to show compliance on a utility system basis and utilize CO_2 reductions from any non-utility fossil fuel reduction project or end-use efficiency measures upon adequate verification.

CO_2 Credit Verification – CO_2 emission reductions quantified through state and utility programs that measure reductions in fossil fuel use should be allowed for compliance.

Emissions Averaging – States should be allowed to structure BSER compliance so that utilities can average emissions across their systems, across state lines, or over the ISO regions.

Extensions and Electric Reliability – States should be allowed to grant both short- and long-term extensions (3 to 5 years) for power plants on either a unit- or system-wide basis.

Biomass – EPA should be considered carbon neutral by default and allowed for use in complying with a fossil fuel BSER performance standard (refer to Item 6 on Biomass).

8) **Biomass**

Fossil Fuel BSER Performance Standards – Biomass fuels, fired in any amount along with fossil fuels, should not be subject to a CO_2 performance standard under this rule-making.

Allowing Biomass for Compliance with a Fossil Fuel Performance Standard - Biomass energy implemented under an existing RPS requirement or derived from, among others, sustainable forestry practices and certification programs (either state or federal), derived from fire hazard reduction projects or invasive species removal, municipal solid waste, industrial biomass process waste, clean demolition biomass, and biogas derived from landfills, manure or biomass digesters, or wastewater treatment plants should be considered CO_2 neutral and creditable towards compliance.

9) **PSD/NRS Permitting**

Permitting for CO_2 Reduction Projects – EPA should exempt projects that reduce CO_2 emissions from PSD/NSR permit requirements.

B. Extended Discussion – Questions 2, 3 & 4

1) **SIP Process**

SIP Deadlines EPA needs to allow states a minimum of 3 years to submit a SIP and a mechanism to allow additional time as needed.

The President directed EPA to finalize BSER guidance by June 2015 and directed states to submit SIPs by June 30, 2016. Wisconsin cannot practically evaluate power plants and consider pertinent variables in determining BSER within thirteen months. In addition, any performance standards or program implemented by Wisconsin will have to be placed into state rule. Currently, the Wisconsin rulemaking process alone takes roughly 3 years. Therefore, Wisconsin anticipates that formulating performance standards followed by incorporation into rule will take 4 or more years to accomplish.

Section 111(d) requires EPA to establish a SIP process “similar” to the SIP process set forth in section 110. Section 110, which applies to NAAQS pollutants, requires SIP submittals within three years of issuance of a NAAQS. CO_2 is not a NAAQS pollutant and does not have the same short-term health-related impacts of a NAAQS pollutant. Therefore, EPA should allow at least the same or more amount of time for a CO_2 SIP submittal.

For these reasons, EPA should allow at least 3 years for developing a CO_2 SIP and provide the flexibility to extend the SIP submittal timeframe as needed.

SIP Flexibility Wisconsin assumes that EPA will provide guidance for determining a performance standard in the form of an emission limitation. However, EPA should also allow the states to develop programmatic alternatives that are equivalent to BSER. This flexibility should include use of existing state RPS and energy efficiency programs, among others, that reduce non-utility fossil fuel use. Other alternatives may include tax-based programs, regulating dispatch through the independent system operators (ISO), or including load service entities (LSE), that act as a utility but do not operate power plants, under the compliance requirements.

SIP Coordination EPA should also allow states to coordinate with other states and ISOs in developing requirements and allowing compliance at the utility system including across state boundaries. States should also be allowed to designate responsible parties other than the power plant operators. This approach may be the best means for allowing compliance flexibilities for multi-state utilities or compliance options that involve supply-side elements not under the control of power plant operators.

2) Credit for Reductions Already Achieved

Wisconsin Utility Investments Wisconsin electric utilities have made major investments, as summarized in Table 2, that have resulted in significant CO_2 emission reductions (refer to Section 1 for further technical details). These investments have been made in response to the retirement of older less efficient power plants, growth in energy demand, state RPS standards and state and federal air emission requirements. These investments do not include those made by power plant operators in order to meet water quality and solid waste environmental requirements.

Table 2. Certain Wisconsin Utility Investments Since 2000.

Category	Action	Capital Cost ($)	Capacity (MW)
Existing Plants	Efficiency upgrades	184,002,375	
	Air Pollution Control Equip.	3,079,602,468	
		3,263,604,843	
New Capacity	Coal	2,904,806,000	1,753
	Coal to Natural Gas (planned)	70,000	297
	Combine Cycle	1,602,823,930	2,150
		4,577,629,930	**4,200**
New Renewable	Wind	2,061,114,924	1,018
	Biomass	255,000,000	100
		2,316,114,924	**1,118**
Electricity Efficiency Programs	Focus on Energy Program	**469,099,037**	
Total Capital Cost		**$10,626,448,734**	

Historic CO_2 Reductions EPA needs to allow credit for actions implemented since 2000 that have reduced power plant CO_2 emissions. EPA can provide credit by allowing states to use these reductions in complying with the BSER requirement.

Wisconsin utilities have been steadily reducing CO_2 emissions since 2000. Wisconsin utilities have improved the average power plant fleet heat rate (efficiency) by approximately 9% and reduced total CO_2 emissions by approximately 16% since 2005. We estimate that our Renewable Portfolio Standard (RPS) has reduced total Wisconsin CO_2 emissions by approximately 10% and our major electric end-use efficiency program reduced CO_2 emissions by approximately 7%. Refer to Section 1 for details of CO_2 emission reductions.

To credit past actions, EPA should consider the following:

a. EPA should allow states to use a period of years around 2005 to determine an average baseline for calculating CO_2 emission credits. States should be allowed to adjust this baseline to account for specific actions back to 2000.

b. Creditable actions should include, among other actions, the retirement of coal-fired generation, repowering and refueling to cleaner fuels, installation of natural gas fired generation, installation of distributed generation and renewable energy, and the reductions from electric end-use efficiency programs.

c. EPA needs to allow credit for all actions taken by Wisconsin utilities in meeting requirements of Wisconsin's RPS requirement. This includes credit for biomass fuels classified as renewable energy under the RPS. To date, Wisconsin utilities have installed approximately 132 MW of woody biomass-fired capacity and currently co-fire waste wood and paper in several other power plants.

d. EPA needs to allow credit for electricity end-use measures implemented in accordance with Wisconsin's Focus on Energy program and other state programs. The efficiency improvements from these programs have been carefully tracked and verified. Refer to Section 1 for detailed discussion of the Focus on Energy program.

e. EPA should also credit voluntary programs and conservation activities that reduce CO_2 emissions from the power sector. Wisconsin utilities have programs and systems in place to verify avoided generation and emissions.

3) Source-based vs. System-based BSER

Wisconsin has reviewed whether BSER performance standards should be set by considering only source-based (power plant) measures for reducing CO_2 emissions or by taking a wider system-based approach that includes power plant measures, transmission improvements, options to decrease electricity load and installation of renewable or cleaner generation. While EPA is considering whether to take a source or system-based approach in setting performance standards, Wisconsin believes that EPA needs to consider the following factors:

a. The majority of Wisconsin stakeholders have indicated that performance standards should be based on what can be achieved at the power plants.

b. Wisconsin is extremely concerned that accounting for actions over the utility system (system-based approach) in order to set performance standards will be very complicated to assess, will require significant state resources in developing a SIP and will result in inequities among the regulated entities.

   The power plants in Wisconsin that may be regulated under this requirement are significantly different in scale and operations. Some utilities operate multiple generation units, own the electric distribution systems and have ready access to renewable electricity. In contrast other utilities purchase most of their power, while yet others only own and operate a single plant. In these cases, basing emission limits on system-wide actions will produce very different performance standards for each utility.

c. Setting a limit based on system-wide actions does not appear consistent with past EPA determinations of BSER under section 111(d) or other federal regulations applicable to power plants.

   For example, section 111(d) requires BSER performance standards for municipal solid waste (MSW) landfill gas emissions. Although, recycling and waste reduction can reduce the amount of landfill gas generated, EPA did not consider these options in formulating BSER for MSW landfill gas.

The power sector has been regulated under various parts of the CAA. In these actions, EPA has consistently developed regulations based on actions and controls limited to the power plant level. For example, under the mercury and air toxics standards rule (MATS) EPA determined that efficiency gains within the power plant are applicable for purposes of reducing emissions associated with electricity generation. However, EPA did not go beyond the plant in evaluating ways to reduce electric generation. Likewise, EPA did not evaluate options to reduce electricity load demand in setting Clean Air Interstate Rule (CAIR) state emission budgets, although EPA had more flexibility to do so.

d. Not all components of the electric utility system are under the control of the regulated entities. As previously noted, the plant, transmission system and distribution system are in many cases owned or controlled by different entities. For example, many of the Wisconsin transmission lines are owned by the American Transmission Company (ATC) which operates independently from the power plant operators. In another example, approximately 50 Wisconsin municipalities are load serving entities (LSE) that purchases 50% to 70% of the electricity they provide to their customers. In this case, the electric system is controlled by four different distinct entities: the power plant operators, the independent system operator (ISO), ATC, and the LSEs. Therefore, assuming a BSER performance standard based on actions across these systems would be problematic.

   In addition, power plant operators cannot control electric demand to the extent that future loads will match assumptions used in setting a BSER performance standard. One reason is that the dispatch of generation units today is controlled more by the ISO than the power plant operators. Another reason is utilities may be able to implement electric end-use efficiency measures, but they cannot ultimately control the electricity demand in areas with population growth or when other measures for pollution reduction such as electric vehicles are being encouraged. Therefore, it is problematic for EPA to build assumptions about future electricity loads into a performance limit.

   Under these circumstances, Wisconsin believes that setting the performance standard based on system-wide actions will create difficulties, inequities and disincentives among the regulated power plants.

e. EPA should not assume that renewable or distributed energy can be adopted in setting a BSER performance standard. This type of energy generation often comes in smaller increments and cannot fully replace individual fossil fuel generation units. Another factor is that renewable energy is often only available on an intermittent basis and typically is not dispatchable (except for biomass) in response to demand. These factors have already resulted in several impacts to Wisconsin plant operations. One impact seen is that coal boiler operators have had to reduce firing loads in order to accept the renewable electricity when it was available instead of calling for renewable energy when it is optimal to reduce the coal boiler load. This has led to these coal units operating at less efficient load point and with increased CO_2 emission rates. Another impact has been lower sales of electricity from coal plant. In this case the utility must pay for the renewable electricity as well as pay for the coal plant. This means either electric rates must increase or it will take longer to pay off the coal plant, possibly delaying retirements.

Another factor to consider is that renewable generation resources are not available to all utilities on an equal basis. For example, Wisconsin utilities purchase a significant amount of wind energy from Iowa and Minnesota. This is because wind generation resources within Wisconsin are not as available or cost-effective when compared to wind energy from those states. In addition, the ability to access this energy is very dependent on transmission capabilities. This transmission access may not be equally available to all utilities at this time.

For these reasons, renewable energy should not be assumed in setting a BSER performance standard. Rather, renewable energy should be available as a compliance option. In this way utilities can integrate renewable energy into their systems in the appropriate manner for both cost-effectiveness and optimal CO_2 benefit.

4) Factors in Setting a Performance Standard

BSER guidance should allow states to determine the achievable CO_2 reductions for each power plant. At a minimum, states must be able to consider factors applicable to the generating unit and supporting facilities such as the type of generation unit, fuel types, size, age, cost-effectiveness and remaining debt. In addressing these factors, it is equally important to consider different types of coal fuels. For example, Wisconsin utilities switched from bituminous to subbituminous coal in order to meet early federal Acid Rain SO_2 emission requirements. This switch often resulted in a decrease in boiler efficiency. Another important factor is that bituminous and subbituminous coals have different CO_2 emission rates.

5) Form of a BSER Performance Standard

The BSER guidance should allow states to structure the BSER performance standard as either a mass or emission rate requirement. A mass based approach may more readily facilitate emissions trading, but an emission rate approach may be necessary in allowing power plants to utilize full unit capacity in responding to ISO dispatch orders. Allowing an emission rate approach may also be necessary to allow full use of the newer, more efficient coal capacity recently built in Wisconsin. In response to a CO_2 rule, this more efficient coal generation may be dispatched more heavily to meet regional load demands. However, assuming a mass cap for the individual power plant or utility may actually hinder the most efficient dispatch of power plants on a regional basis. Also, as noted above, reduced loading may actually prolong the time until coal plant debt is paid and the units can be retired.

6) Compliance Timeframes

Wisconsin believes that EPA must allow a minimum of 7 years after BSER guidelines are finalized before requiring compliance with a source-based BSER performance standard. Further, Wisconsin believes that states should be able to grant additional time to an individual unit or a utility as a whole. If EPA uses the alternative approach of setting a performance standard based on system-wide actions, then Wisconsin believes the compliance timeframes must also be longer.

Enabling states to identify appropriate compliance timeframes based on achievability and need is the best way of ensuring that utility operators can utilize the full breadth of available compliance options including: power plant upgrades, renewable generation, new natural gas generation, transmission upgrades, major industrial energy repowering projects and energy end-use efficiency measures. In addition, states should be allowed to grant long-term compliance extensions based on need. Extensions should also be allowed in order to accommodate options that result in better long-term and more cost-effective reduction approaches.

EPA should consider the following in evaluating compliance timeframes and requirements:

a. Compliance costs will increase dramatically if current debt in coal plants is stranded or generation is retired prematurely. Since 2000, Wisconsin utilities have invested over 3.2 billion dollars in upgrades and air pollution control equipment for existing power plants (Table 2, below). This debt is generally amortized over a 20 to 30 year period and will be ongoing debt for a significant period into the future. Ratepayers will have to pay this cost regardless of whether the plants are still operating.

b. EPA has the authority to allow flexible compliance timeframes based on achievability and need. As previously stated, section 111(d) directs EPA to establish a SIP process similar to section 110. Section 110 does not set compliance timeframes for non-NAAQS pollutants such as CO_2. Section 111(d) also directs EPA to allow methodologies that account for the remaining lifetime of power plants. These factors indicate that states should be able to set different compliance timeframes or requirements based on achievability and the remaining useful life of each power plant.

c. Significant efficiency upgrades to existing power plants are expected to take at least 4 to 5 years from planning to operation. In one ongoing Wisconsin project at a 1,000 megawatt (MW) power plant to increase efficiency, upgrades for the steam turbine and coal pulverizers will take more than 4 years from planning to completion. As a note, the capital investment for this type of project is expected to be on the order of 130 million dollars.

d. EPA should consider that if the compliance time is too short, the electric utilities may not be able to have sufficient time for installing renewable or more efficient generation. Instead, the utilities may have to rely more heavily on upgrading existing older plants. Currently, one new combined cycle unit being evaluated for installation in Wisconsin may take seven or more years from planning to commission. As previously described, it may also take considerable time to integrate renewable energy into the generation supply without adversely affecting current operations. A short compliance deadline may forego these approaches

7) <u>Compliance Flexibility</u>

Wisconsin believes that maximum compliance flexibility is necessary under a CO_2 BSER requirement for power plants. This compliance flexibility should consider the following:

a. All stakeholders agree that credit for any type of CO_2 reduction should be allowed towards compliance as long as there is adequate quantification and verification.

b. CO_2 emissions are very consistent for the specific types of fossil fuels (e.g. natural gas, subbituminous coal, bituminous coal, petroleum coke, distillate oil, etc…) and are not affected by the type of combustion unit. Therefore, quantifying emission reductions can simply be accomplished by tracking fuel consumption and does not require intensive emissions monitoring. Thus, EPA should allow CO_2 reductions from any residential, commercial or industrial end-use efficiency and repowering projects where the reduction in fuel use has been quantified.

c. The BSER guidance should allow utilities to demonstrate compliance on a system-wide basis and in a manner that credits improvement in both the supply-side and demand side systems.

d. EPA should allow states to use their RPS and energy end-use programs in demonstrating compliance. Wisconsin has programs in place that carefully track electric generation reductions and related CO_2 emission reductions.

e. EPA should allow states to use existing systems for tracking renewable electricity, such as the M-RETS system discussed in Section 1.

f. EPA should allow states to designate compliance requirements to the utility, the utility system or to other responsible parties. One example may be that compliance is demonstrated by the ISO. Another example is to have load selling entities (LSE) demonstrate compliance with CO_2 requirements. The states should have the option under any rule structure to make these decisions.

g. As discussed in Section 1, renewable electricity generated out-of-state and owned or contracted by Wisconsin utilities should be creditable towards meeting Wisconsin utility BSER requirements.

8) <u>Biomass</u>

Biomass energy is an extremely important energy source for Wisconsin that should be viewed as carbon neutral. The State of Wisconsin believes that biomass should not be subject to a performance standard when co-fired with fossil fuels. Rather biomass energy should be allowed for compliance with BSER requirements. In addition, any biomass energy generation implemented according to state RPS requirements should be creditable towards compliance with a BSER performance standard.

Wisconsin also believes that the states are in the best position for determining whether biomass should be considered carbon neutral based on factors specific to each state or region. States, at a minimum, should be able to certify CO_2 neutrality for biomass harvested under state or federal sustainable forestry practices and for energy derived from, among others, industrial and commercial process biomass waste, municipal solid waste, landfill gas, anaerobic digester gas, and wastewater treatment plant gases.

In looking at this issue, we believe that EPA should consider the following:

a. The Wisconsin RPS requirement identifies biomass as a renewable resource. Wisconsin utilities have installed or converted over 132 MW of biomass fired capacity. Utilities are also co-firing additional fossil fuel capacity with waste paper and biomass. These actions should be creditable towards compliance with a BSER CO_2 performance standard.

b. Wisconsin is home to a substantial paper industry. This activity results in woody waste and waste paper product at the plant that is typically used for steam and electric power. EPA must not set a precedent that this biomass should be regulated in the same manner as fossil fuels.

c. Wisconsin has a best management practices program structured to address different sustainability issues including forest regeneration, water quality and wildlife habitat. In additional, both the state forests and many private forests enrolled in the state's managed forest program receive certification of sustainable forestry under national and internationally accepted standards. Much of the woody biomass currently fired by utilities is collected under these programs and therefore should be accepted as CO_2 neutral by EPA. Wisconsin believes that each state is in the best position to evaluate these factors and determine requirements for sustainability and CO_2 neutrality. The same should be applicable for biomass harvested according to federal sustainable forestry guidelines.

d. Biomass harvested as part of a fire hazard reduction activity or that results as clean-up from natural disasters should be considered CO_2 neutral.

e. The use of woody biomass helps to maintain the large forest base in Wisconsin. For EPA to set a default that woody biomass is not CO_2 neutral may result in fewer acres kept in forest and a net increase in CO_2 emission due to land-use change. Once again, the states are often in the best position to make these determinations.

f. One utility fires woody waste obtained from the demolition of buildings and waste obtained by removal of invasive trees by municipalities. These practices are beneficial to avoiding generation of landfill gases and restores native sustainable species. Burning of these types of biomass fuels should be considered CO_2 neutral.

g. Biogas energy from digesters and landfills should be considered CO_2 neutral. Wisconsin is home to a large dairy industry with an increasing number of manure and waste digesters that produce biogas for electricity generation. In addition, landfills and wastewater treatment plants are working to capture methane gases for electric generation. These practices have obvious environmental benefits and also reduce methane GHG emissions to the atmosphere.

h. EPA should consider establishing a process whereby a utility operator or operator of a monoculture biomass crop or forest can demonstrate a closed loop system or the appropriate carbon rating.

Perspective of 18 States on Greenhouse Gas Emission Performance Standards for Existing Sources under § 111(d) of the Clean Air Act.

Introduction

As State Attorneys General, we believe it is critical to bring public awareness to another example of what has unfortunately become routine: the United States Environmental Protection Agency ("EPA" or "Agency") is poised to yet again propose new regulations that venture well beyond the limits of the agency's authority. The President has called upon EPA to propose greenhouse gas (GHG) emission standards, regulations, or guidelines for *existing* power plants by June 1, 2014, and to finalize those rules by June 1, 2015. As this paper will show, EPA's authority under the Clean Air Act is limited to developing a procedure for *states* to establish emissions standards for existing sources. EPA, if unchecked, will continue to implement regulations which far exceed its statutory authority to the detriment of the States, in whom Congress has vested authority under the Clean Air Act, and whose citizenry and industries will ultimately pay the price of these costly and ineffective regulations.

Last year, EPA published a proposed rule regulating carbon dioxide ("CO_2") emissions from new electric utility generating units ("EGUs"). 77 Fed. Reg. 22,392 (April 13, 2012) ("EGU NSPS"). In light of recent comments from industry, EPA is considering the need to re-propose this standard due to its failure to finalize the action within the CAA's 1-year timeframe. In addition, on April 15 and 17, 2013, some states and environmental groups filed 60- and 180-day Notices of Intent to sue EPA under section 304(a) of the Clean Air Act ("CAA") for failure to perform the allegedly non-discretionary duty of and/or unreasonably delaying finalizing the

EGU NSPS and proposing standards for existing EGUs.[1] In response to these Notices, a coalition of Attorneys General has requested to be involved in any settlement discussions with advocates of broad federal GHG regulations.

EPA states that once it has issued regulations for an air pollutant from *new* sources in a particular source category under the CAA § 111(b), it has legal authority to regulate emissions from *existing* sources of that air pollutant within the same source category.[2] The final version of the new source performance standards for new EGUs will likely face legal challenge. However, the following analysis assumes the final EGU NSPS for GHG emissions is upheld and EPA moves forward with rulemaking for existing sources.

The purpose of this paper is to identify a timely example of a serious, ongoing problem in environmental regulation: the tendency of EPA to seek to expand the scope of its jurisdiction at the cost of relegating the role of the States to merely implementing whatever Washington prescribes, regardless of its wisdom, cost, or efficiency in light of local circumstances. The issue is not new. The States and EPA have been at odds over the scope of their respective responsibilities under the federal environmental statutes since the statutes' inception. The recent increase in the level of federal regulatory activity under the Clean Air Act has generated a

[1] A settlement agreement entered into by a number of states and environmental groups in December 2010 set forth deadlines for EPA to issue regulations with respect to GHG emissions from existing EGUs. See, 75 Fed. Reg. 82,392 (Dec. 20, 2010). The deadlines have passed.

[2] The authority of EPA to promulgate GHG NSPS for existing EGUs, even if it finalizes its proposed GHG NSPS rule for new EGUs, has been questioned. *See* William J. Hann, The Clean Air Act as an Obstacle to the Environmental Protection Agency's Anticipated Attempt to Regulate Greenhouse Gas Emissions from Existing Power Plants, THE FEDERALIST SOCIETY (Mar. 2013), available at http://www.fed-soc.org/publications/detail/the-clean-air-act-as-an-obstacle-to-the-environmental-protection-agencys-anticipated-attempt-to-regulate-greenhouse-gas-emissions-from-existing-power-plants. Without conceding that EPA does have authority to promulgate a GHG NSPS for existing EGUs, we assume for purposes of discussion here that EPA does have that authority and will exercise it.

corresponding increase in concerns among the States regarding the preservation of their role in environmental protection.

The way in which EPA has "pushed the envelope" in interpreting its legal authority under the CAA to promulgate a New Source Performance Standard for new EGUs portends a similarly aggressive and unlawful approach to the regulation of existing EGUs. EPA's clear policy goal in establishing its new source standards is to prevent the construction of new coal plants. EPA's proposed EGU NSPS would foreclose the construction of new coal-based electric generation absent carbon capture and storage ("CCS"), yet CCS is likely to remain commercially infeasible for a decade or more. The elimination of coal as a fuel for new electric generation would have highly concerning implications for electricity prices and for the economy and job-creation in general, as well as the competitiveness of American manufacturing.

In order to justify its proposed standard that would not allow new coal-based EGUs absent CCS, EPA has taken unprecedented steps. The Agency proposed to combine coal and combined-cycle natural-gas units into a single regulatory category, something it has never done before for coal and gas EGUs. Indeed, it did not even go so far as recently as last year when it proposed NSPS for traditional pollutants emitted by EGUs. EPA's aggressive posture in its proposed new-source NSPS, both as to foreclosing new coal plants and in pushing the scope of its claimed legal authority, raises serious questions as to the approach EPA will eventually take when it promulgates existing-source NSPS.

If EPA proceeds against existing coal plants with the same hostility, it is likely to be reversed in court. As this paper shows, EPA does not have authority to promulgate prescriptive limitations for existing coal-fueled EGUs. Under section 111(d) of the CAA, EPA must recognize that States have broad discretion to determine the nature of NSPS requirements for existing EGUs. EPA may require States to adopt standards, and EPA may guide how States do so procedurally, but the States are vested with the legal authority to decide the ultimate standards.

The Statutory and Regulatory Framework For Developing Performance Standards For Existing Sources

The focus of the following analysis is the limitations Congress placed on EPA's authority under Section 111(d) of the CAA. Section 111(d) provides EPA with the authority to develop standards of performance for existing sources and directs the Agency to:

> prescribe regulations which shall establish a procedure similar to that provided by section 7410 of this title under which each State shall submit to the Administrator a plan which establishes standards of performance for any existing source for any air pollutant…to which a standard of performance under this section would apply if such existing source were a new source.

Section 111(d) requires the existence of a performance standard for new sources as a condition precedent to the development of such standards for existing sources. Thus, the legality of the final version of EPA's EGU NSPS rule has significant implications for EPA's ability to require regulation of existing EGUs.

Most importantly, section 111(d) invokes the principle of cooperative federalism – with roles clearly delineated for both EPA and the States. The reference to § 110 refers to the general process by which States submit their State Implementation Plans ("SIPs") for EPA review. Accordingly, EPA's authority under § 111(d) is limited to establishing, in the statute's term, a "*procedure*" by which the States submit plans for regulating existing sources. EPA cannot promulgate rules establishing the substantive standards to be imposed on existing sources.

The cooperative federalism is illustrated by EPA's general procedural regulations relating to the States' adoption and submittal of plans establishing standards of performance for existing sources. Those regulations require EPA to issue a "guideline document" concurrently with, or after, the "proposal of standards of performance for the control of a designated pollutant from affected facilities." 40 C.F.R. § 60.22(a). The content of the guideline document is of great importance to the preservation of the States' role in the development of performance standards for existing sources.

Under EPA's regulations, the guideline document is to "provide information for the development of State plans" including a "description of systems of emissions reduction which, in the judgment of the Administrator, have been adequately demonstrated." *Id* at (b)(2). The guideline document also shall contain an "emission guideline" providing "criteria for judging the adequacy" of § 111(d) plans. 40 C.F.R. § 60.22(b)(5); *see*, 40 Fed. Reg. 53,341 (Nov. 17, 1975). The emission guideline "reflects the application of the best system of emission reduction (considering the cost of such reduction) that has been adequately demonstrated." 40 C.F.R. § 60.22(b)(5). The emission guideline must also allow sub-categorization "when costs of control, physical limitations, geographical location, or similar factors make [it] appropriate." *Id*.

Also under EPA's regulations, the States have nine months to submit a "plan for the control of the designated pollutant to which the guideline document applies." 40 C.F.R. § 60.23(a)(1). The plan "shall include emission standards" that "shall prescribe allowable rates of emissions except when it is clearly impracticable." 40 C.F.R. § 60.24(a), (b)(1). The States have significant discretion in formulating these plans. Although the "emission standards" are to be "no less stringent than the corresponding emission guideline(s), the States may make a case-by-case determination that a specific facility or class of facilities should be subject to a less-stringent standard or longer compliance schedule due to 1) cost of control; 2) physical limitation of installing necessary control equipment; and 3) other factors making the less-stringent standard more reasonable. *See*, 40 C.F.R. § 60.24(c), (f). EPA then has four months to determine whether the plan meets the requirements discussed above. If EPA disapproves the plan, the State may correct the deficiencies or, under EPA's construction, the Agency may issue its own plan within 6 months of the original submission deadline. *See*, 40 C.F.R. § 60.27(c), (d).

Although these regulations have never been tested in court, EPA undoubtedly has power to adopt procedural regulations governing State adoption of plans setting forth performance standards. But, importantly, and consistent with the statute, the determination of the actual substantive standards is left to the states.

Existing Source Performance Standards for CO_2 Emissions from EGUs

In contemplating regulation of existing EGUs, however, EPA appears poised to go beyond the establishment of procedures and usurp the states' authority by setting minimum *substantive* requirements for state performance standards. Having reviewed the statutory and regulatory requirements for developing standards of performance for existing sources in a general sense, we now apply that legal framework to CO_2 emissions from EGUs. Although EPA has not yet issued a proposed guideline document for CO_2 emissions from existing EGUs, we offer general observations about potential issues that have already presented themselves.

Fundamentally, § 111(d), as well as EPA's own regulations, require that emission reductions be made through adequately demonstrated systems of emission reduction technology. Under § 111(d), EPA establishes procedures for States to submit plans containing "performance standards." "Performance standards" is defined in § 111(a): "The term 'standard of performance' means a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines *has been adequately demonstrated*." (Emphasis supplied). And EPA's guideline document and the emission guideline contained therein are to "reflect[] the application of the best system of emission reduction (considering the cost of such reduction) that has been adequately demonstrated." 40 C.F.R. § 60.22(b)(5); *see also*, 42 U.S.C. § 7411(1) (definition of "standard of performance"). The crux of this requirement thus is that the system be, in fact, adequately demonstrated.

It seems incontrovertible that no post-combustion reduction system has been "adequately demonstrated" for CO_2 emissions from EGUs on a broad, commercial scale. A system of carbon capture and storage is perhaps a decade away from being technologically and economically feasible. A permitting system for storing CO_2 emissions underground and a set of legal rules governing liability for CO_2 storage has not been put in place in most states. Without an adequately demonstrated post-combustion control technology, EPA must look to standards based on cost-effective efficiency improvements at electric generating units, because more efficient units will produce lower CO_2 emissions per unit of heat input or electricity output.

EPA and others may believe that efficiency measures will not ensure the amount of CO_2 emission reductions they desire. As a result, some groups have proposed EPA be given flexibility to develop emission guidelines based on trading programs with statewide emissions caps, increased reliance on lower CO_2 emitting facilities, or demand-side and non-regulated source reductions. In short, EPA may attempt to force coal-fueled EGUs to decrease operation time or retire early, or force utilities to rely more heavily on natural gas and other resources in an effort to ensure greater CO_2 emission reductions. Such proposals, often offered as ways of providing "flexibility," do not conform to the limitations Congress has placed on EPA in the

Clean Air Act, nor do they properly preserve the primary role of States in the development of standards of performance for existing sources. Under § 111(d), it is the States, not EPA, that are authorized to adopt performance standards; therefore it is the States, not EPA, that weigh the § 111(a)(1) factors to determine what technology is adequately demonstrated. Simply put, EPA lacks statutory authority (and is limited by its own regulations) to issue emission guidelines seeking reductions of CO_2 emissions from coal-based EGUs in a manner based on something other than an adequately demonstrated reduction system for such EGUs.

To the extent § 111(d) provides authority for flexible approaches to establishing performance standards to seek reductions in CO_2 emissions, that authority is vested in States, not EPA. And of course, under § 116, States retain authority to adopt more stringent CO_2 controls than EPA has the authority to mandate.

As noted, § 111(d) specifies that EPA's regulatory authority is limited to developing a *procedure* for the submission of state plans. EPA's general regulations authorizing the issuance of emission guidelines that establish minimum requirements, depending on how EPA implements this guideline authority in a particular case, bear on substantive standard-setting. But EPA does not have the authority to establish minimum substantive requirements.

EPA cannot dictate substantive outcomes. The agency can require that States actually adopt performance standards based on application of the § 111(a)(1) factors.

States are additionally afforded the discretion to consider "among other factors, the remaining useful life of the existing source to which such standard applies" when developing performance standards for existing units. Beyond this, § 111(d) does not provide authority for EPA to reject a State plan if it does not contain a standard of performance as that term is defined, and based on the factors set forth, in § 111(a)(1).

In sum, the CAA imposes responsibility for air pollution control at the State and local levels because of the proximity to existing sources and familiarity with local operating conditions. State implementation plans are thus the primary architecture of emission controls. *See* §§ 107(a); 110(a); 111(d). The "structure of the CAA militates against reading an extra-statutory requirement into the Act's limitations on state discretion. Because the states enjoy 'wide discretion' in implementing the Act, the imposition of newfound restrictions upsets the Act's careful balance between state and federal authority. *Union Elec. Co.*, 427 U.S. at 250; *see also Fla. Power & Light Co.*, 650 F.2d at 587 ('The great flexibility accorded the states under the Clean Air Act is . . . illustrated by the sharply contrasting, narrow role to be played by EPA.')." *Luminant Generation Co. v. EPA*, 675 F.3d 917, 929 (5th Cir. 2012). EPA's role for existing sources is therefore "confine[d]…to the ministerial function of reviewing SIPs for consistency with the Act's requirements." *Luminant Generation Co. v. EPA*, 675 F.3d 917, 921 (5th Cir. 2012).

Conclusion

The prospect for EPA adoption of GHG performance standards for new or existing coal-based EGUs raises serious concerns. EPA's aggressive standards for new coal-based EGUs indicate a similarly aggressive approach to existing coal-based EGUs. While EPA is authorized to require States to submit plans containing performance standards, EPA may not dictate what those performance standards shall be. Nor may EPA require States to adopt GHG performance standards that are not based on adequately demonstrated technology or that mandate, in the guise of "flexible approaches," the retirement or reduced operation of still-viable coal-based EGUs.

These concerns are serious. EPA regulations may harm the nascent economic recovery. Moreover, our federalist system of government, as implicated in the CAA, requires that EPA recognize the rights and prerogatives of States. The extent and form of greenhouse gas regulation is important to the States; it is critical that States be allowed to play their proper roles in making the significant policy judgments that are required in adopting any such regulation.

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West Virginia Attorney General

Tom Easterly
Commissioner, Indiana Department
of Environmental Management

September 9, 2014

Honorable Barack Obama
President of the United States
The White House
1600 Pennsylvania Avenue, NW
Washington, DC 20500

Dear President Obama:

As governors of affected states, we write to express our concerns about the Environmental Protection Agency's (EPA or Agency) recent proposal for reducing carbon dioxide emissions at existing power plants. Our country needs a coherent, consistent energy policy that promotes reliable and affordable energy in addition to a healthy environment. However, we cannot achieve this end without a sincere partnership between the states and the federal government, whereby EPA appropriately recognizes the limits of federal authority. EPA's proposed rule for reducing carbon emissions, pursuant to Section 111(d) of the Clean Air Act (CAA or Act), fails to strike this necessary balance.

The unambiguous language of the CAA expressly prohibits EPA from using Section 111(d) to regulate power plants because EPA already regulates these sources under another section of the Act.[1] Moreover, even if the Agency did have legal authority to regulate power plants under 111(d), it overstepped this hypothetical authority when it acted to coerce states to adopt compliance measures that *do not reduce emissions at the entities EPA has set out to regulate*. Under federal law, EPA has the authority to regulate emissions from specific sources, but that authority does not extend outside the physical boundaries of such sources (*i.e.*, "outside the fence").[2] In attempting to regulate outside the fence, the Agency's proposal not only exceeds the scope of federal law, but also, in some cases, directly conflicts with established state law.[3]

In addition to these legal prohibitions, the rule poses numerous practical problems for state compliance. These problems reflect your Administration's decision to move forward with the proposed regulation without considering or understanding—among other crucial matters—our state energy markets and infrastructure needs.

[1] As state petitioners argued in a 2007 lawsuit concerning the Clean Air Mercury Rule ("CAMR"): "Subsection (d) of Section 111 provides authority for regulation of existing sources, but is explicitly limited to those air pollutants that are not 'emitted from a source category which is regulated under section 7412 of this title.'" *See* 2007 Opening Brief of CAMR State Petitioners (New Jersey, California, Connecticut, Delaware, Illinois, Maine, Massachusetts, Minnesota, New Hampshire, New Mexico, New York, Rhode Island, Vermont, and Wisconsin).

[2] The proposal also fails to appreciate that state agencies enforcing air quality standards have no authority to enforce reductions outside the fence.

[3] Under existing law, Kansas, Kentucky, Louisiana, Missouri, and West Virginia cannot regulate emissions from power plants by shifting pollution-control costs to other parts of the economy. Emissions reductions must occur at the power plant source.

Below, we highlight some of the more urgent and vexing compliance issues inherent in the proposal, while cautioning that this list is by no means exhaustive. We request that your Administration provides informed plans to address these significant obstacles to state compliance and that it does so well in advance of the proposal's comment deadline of October 16. If you cannot fulfill this obligation in time for states to incorporate the new information into their comments, your Administration should withdraw the proposal until it gives due consideration to these critical concerns.

1. Enforcement of State Plans

At a recent Senate hearing on the proposal, EPA Administrator McCarthy failed to answer questions pertaining to EPA's intentions to enforce provisions in State Plans that currently fall outside EPA's authority. For example, while the Administrator acknowledged that EPA lacks the authority to require a state to adopt a renewable portfolio standard (RPS), she repeatedly dodged the question of whether EPA believes it has the authority to enforce an RPS once a state submits it as part of a State Plan. Without clarification, we are left to assume that EPA is entertaining the possibility of overreaching its authority in this area.

a. Under your proposal, if a state adopts a renewable portfolio standard (RPS) and/or an Energy Efficiency Resource Standard (EERS) as part of its compliance strategy and later softens or repeals the RPS and/or EERS, does EPA claim to have the authority to enforce the original RPS and/or EERS irrespective of subsequent legislation? If so, what is the source of EPA's legal authority to take such action?
b. If EPA rejects a State Plan (or if a state fails to submit one), will EPA then attempt to force an RPS and/or EERS on a state via a Federal Plan, despite EPA's admission that it lacks the authority to do so? If so, how does EPA reconcile this action with having conceded to an absence of such authority?

2. Availability and Impacts of Renewable Energy

Your proposal makes broad assumptions about access to renewables. For example, EPA identifies potential renewable energy targets for individual states by looking at the scope of renewable energy mandates in an arbitrarily-defined *region* without any regard for the actual availability of renewable resources or saturation points in the *individual* states. EPA also fails to consider how increased renewable penetration will impact grid reliability and existing baseload capacity.

a. Has the federal government conducted an analysis to determine the environmental impact of building renewable energy systems at the scale envisioned in the proposal? For example, one nuclear plant producing 1,800 MWs of electricity occupies about 1,100 acres, while wind turbines producing the same amount of electricity would require hundreds of thousands of acres. If such an analysis exists, please provide detailed information related to that analysis. If such an analysis does not exist, please explain why the analysis was not performed.
b. Given the amount of land required by renewable energy systems, has your Administration considered that federal land permitting requirements may preclude or stall the development of renewable projects? Also, expanding the deployment of wind and solar farms could readily conflict with the Endangered Species Act (ESA). Indeed, one can easily envision the plausible scenario whereby the ESA, operating as federal law separate from the CAA, could prevent state compliance with EPA's emissions targets. How does your Administration propose to avoid these conflicts?
c. Has the Administration mapped out a transition pathway for renewables from an artificial to a competitive market? Specifically, what is the federal plan to commercialize storage technology, which is necessary for that transition?

3. Construction and Funding for Natural Gas Infrastructure

Your proposal entails significant fuel switching from coal to natural gas, but most retiring coal plants cannot simply be replaced by natural gas plants. Before this switch can occur, gas infrastructure, including storage facilities, must be built. The necessary pipelines require permits, and in many cases, federal approval. Before your proposal, studies indicated the need for more than $300 billion in gas infrastructure investment between now and 2035. Currently, EPA projects that its proposal will result in nearly 50 gigawatts of retirements of baseload coal generation between 2016 and 2020, creating an even greater demand for infrastructure investment.

a. What steps will your Administration take to ensure the necessary construction of interstate natural gas infrastructure, including pipelines? Will you consider expediting the environmental impact study (EIS) process so that gas transmission can be built to serve constrained regions?
b. What is the estimated cost of the gas infrastructure required to meet compliance targets under your proposal, and who does the federal government foresee paying for it?

4. Disposal of Civil Nuclear Waste

Your proposal also supports nuclear power as a key part of your carbon dioxide emissions reduction strategy. Since renewables cannot replace the baseload generation attributes of retiring coal plants, maintaining existing reactors and building new units is essential for many states to reach their assigned reduction targets. However, at least nine states have bans on new nuclear builds, which will remain in effect until the federal government, at least to some degree, resolves the waste disposal issue.[4]

a. Given your Administration's opposition to make use of the Yucca Mountain repository, will you bring forward a viable, long-term solution for disposal that would win public support and the necessary votes in Congress? And if so, when?
b. If not, does your Administration expect the states with bans on new nuclear facilities to revise their laws, despite the federal government's failure to adequately address the waste issue?

5. Importing and Exporting Electricity

A number of states cannot meet their electricity demands without substantial imports of power. Indeed, many states host electric utilities that have existing contracts with distribution companies outside their borders. Accordingly, the shutdown of coal plants in an exporting state could also constrain power supply in an importing state. It is evident that EPA failed to consider this "offshoring" of power requirements, and the corresponding carbon footprint, when it assigned reduction targets to the states.

a. Why would EPA unfairly penalize those states that have made adequate power generation investments, which allow them to help other states achieve secure electricity supply?
b. Under the proposal, when exporting states must shut down coal plants, they could face serious constraints on generation resources, particularly during extreme weather. These constraints could create a difficult choice for states: allow their utilities to fulfill existing contracts with entities outside the state or service the citizens of the home state first. Has your Administration considered the potential negative impact this proposal could have on commerce within the United States? If so, please explain how you propose to address this issue.
c. Has EPA adequately consulted with the entities charged with developing and enforcing reliability standards and with monitoring the bulk power system (*e.g.,* Federal Energy Regulatory Commission (FERC) and the North American Electric Reliability Corporation (NERC)) on the proposal? If so, what did FERC, NERC, and/or other such agencies and departments have to say about how the rule will impact (i) variable energy resource integration; (ii) baseload generation; and (iii) grid reliability?

The economic health of our nation depends on accomplishing a balanced energy and environment policy. The United States should be pursuing a strategy that achieves its objectives without severely harming our economies and pitting states against one another. To help facilitate a successful energy policy, we bring these important state concerns to your attention and request thoughtful answers to our questions. Thank you in advance for your cooperation, and we look forward to your response.

[4] California, Connecticut, Illinois, Kentucky, Maine, New Jersey, Oregon, West Virginia, and Wisconsin.

Sincerely,

Governor Robert J. Bentley
Alabama

Governor Sean Parnell
Alaska

Governor Janice K. Brewer
Arizona

Governor C.L. "Butch" Otter
Idaho

Governor Mike Pence
Indiana

Governor Phil Bryant
Mississippi

Governor Susana Martinez
New Mexico

Governor Pat McCrory
North Carolina

Governor Jack Dalrymple
North Dakota

Governor Mary Fallin
Oklahoma

Governor Tom Corbett
Pennsylvania

Governor Nikki Haley
South Carolina

Governor Gary R. Herbert
Utah

Governor Scott Walker
Wisconsin

Governor Matthew H. Mead
Wyoming