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September 5, 2014

Angela Dickens
Wisconsin Department of Natural Resources
101 S. Webster Street
PO Box 7921
Madison, WI 53707-7921

Delanie Breuer
Public Service Commission of Wisconsin
610 North Whitney Way
Madison, WI 53705

Dear Ms. Dickens and Ms. Breuer:

Enclosed are the responses of Wisconsin Public Service Corporation (WPS) to the WDNR and PSCW Questions on EPA's Clean Power Plan Proposal. WPS participated with the other Wisconsin utilities in developing joint responses to many of the questions. In this submittal, we've included a reference to the joint responses and for the rest of the questions, a response specific to our system and/or position on the issue.

We are very appreciative of the opportunity to share this information and look forward to further discussions and participation in the development of the state's positions and comments to the EPA.

Sincerely,

Connie K. Lawniczak

Connie Lawniczak
Assistant Vice President
Shared Services and Environmental Services
for Wisconsin Public Service

Enc.

ckl/rjf

cc:
Mr. Tom Smies, WPS - D2
Mr. David Wanner, WPS – D2
Mr. Randy Oswald, IBS – D2
Mr. Paul Spicer, WPS – D2
Ms. Connie Schmoll, WPS - G4
Mr. Dennis Derricks, IBS – G3
Mr. Rob Benninghoff, WPS – G4
Mr. Merlin Raab, WPS – G4
Ms. Ronda Ferguson, IBS – G3
Mr. Tom Karman, DNR
Mr. Ken Detmer, PSCW

WDNR and PSCW Questions on EPA's Clean Power Plan Proposal.

In addition to supporting the comments made by the Joint Wisconsin Utilities, Wisconsin Public Service Corporation (WPS) offers the following comments in response to the WDNR/PSCW questions on EPA's Clean Power Plan proposal. These comments are offered with the overall goal of influencing the EPA final rule so that:

1) The state is not harmed
2) Existing renewable investment "counts"
3) Out of state/country options are available (i.e., keep lowest cost options available and provide diversity)
4) Reliability is not harmed
    a. Timing is critical so that the schedule to comply with the proposed rule does not compromise the industry's capability to manage the various risks
5) Existing asset investments are maximized
    a. Compliance with the rule may compromise past investments in coal fueled generation.

I. OVERARCHING ISSUES.

a. **Electrical Reliability**. What factors or analyses need to be considered to evaluate impacts of this rule on electric reliability? Does the use of emissions averaging periods adequately ensure electrical reliability? Could other mechanisms help with this issue (e.g. MACT-type extensions, fail-safe/off ramp for emergencies, etc.)?

WPS Response: In terms of analysis, MISO needs to determine if it can reliably serve load while maintaining the CO_2 target rate that is representative of the states MISO serves. The rule changes the MISO generation system from a system which, with the exception of its wind generation, was largely "capacity limited" (generating units that can generate Mwh up to the units availability if necessary) to a system which has two "energy limited" subsystems: coal units (which have emission restrictions) and simple cycle combustion turbines (annual capacity factor has to be less than 1/3 of full output in order to avoided being an "affected" unit).

This change in system attribute creates significant uncertainty in operating the system. Generating unit owners have to develop bid strategies that assure environmental compliance, maximize energy revenues and assure reliable operation.

In addition to the complications of the capacity and energy market issues across ISO seams, the ISO will also have to manage the impact of compliance with the proposed CO_2 rule. This applies to both within the US and across international borders. For instance, MISO relies upon almost 2,000 MW of capacity from Manitoba hydro alone and this rule will impact the value of that capacity and the use of the associated energy.

Also, the rule will impact and possibly limit the options the ISO has in terms of operating SSR units (units required for reliability by ISO) to provide capacity and energy in order to assure reliable delivery of electricity to customers.

In summary, the rule needs to include fail-safe/off ramps in order to assure reliable operation of the system.

b. **Stranded Costs.** How does the proposed rule impact previous investments in emission controls, including type and magnitude of impact? Does the proposed rule include options to avoid stranded costs? If not, what could EPA change to address this? Is a certain level of stranded costs acceptable, and if so, what level?

WPS Response: It is too early to tell what the exact impact of the rule will be on existing coal units. Generally one would expect to see reduced operation on existing coal units to the point that units "may" have to be taken off line for a number of weeks in the spring and fall (during low peak load seasons) in order to reduce the amount of CO_2 emitted. If this condition develops economic analysis will need to be done to determine the least cost plan, continue to operate low load factor coal units or replace with another form of generation.

To avoid the stranded cost issue, the EPA has to allow for CO_2 emission offsets from other economic sectors (agriculture crop tillage practices, reforestation, and avoided deforestation). Constraining emission rate reduction options to just renewable generation and energy efficiency results in having no choice but to reduce operation of coal units (or even natural gas units in states with a limit lower than a natural gas unit emission rate) in order to increase use of renewables and energy efficiency. It is an either/or situation if you do not have access to offsets from other sectors.

c. **System- versus unit-based approach.** Please comment on the EPA's consideration of the electrical system as a whole in setting BSER (best system of emission reduction), and the EPA's interpretation of what is an 'adequately demonstrated' BSER. Would an 'inside the fence line' approach be more appropriate for goal setting and/or compliance? Why or why not? Please discuss any related legal concerns.

WPS Response: WPS has reviewed the legal analyses done by the Edison Electric Institute (EEI) and the Utilities Air Regulatory Groups (UARG). While there are many potential legal issues that are likely to be the basis of challenges, one of the major issues is whether or not EPA has adequately justified its "building block" approach for determining the "best system of emission reduction" (BSER) as required by the Clean Air Act. EPA has not sufficiently evaluated whether its BSER blocks work together as a system. Also, EPA has not demonstrated that the "system" as outlined has been "adequately demonstrated" or that the resulting standards are "achievable."

Another issue of potential challenge is that the EPA has interpreted BSER to include actions that shift generation among regulated facilities to take advantage of lower emitting NGCC (Building Block 2) and increase reliance on low- or zero-carbon emitting facilities that are not affected EGUs such as certain nuclear and renewable power plants (Building Block 3). EPA has also included "negawatts" from end-use efficiency projects that occur outside the electric generation sector (Building Block 4). EPA's reading of "best system" to include actions taken outside affected Electric Generating Units (EGUs) fence line is inconsistent with the terms of section 111. Consistent with the definition of "standard of performance," a "standard for emissions" of GHGs for existing EGUs must reflect the degree of emission limitation "achievable through application" of the best system of emission reduction. Zero-carbon generation and energy savings cannot be "applied" to EGUs as they occur outside of the EGU. Therefore a determination of BSER that includes measures outside of a facility which cannot be applied to the facility cannot serve as part of a standard of performance.

II. **SETTING STATE GOALS.**

a. **Baseline.** EPA set the BSER requirements based on a 2012 baseline.

   i. Does this baseline adequately credit, or conversely penalize, states and utilities for early action? If the latter, would a different year or type of baseline be more appropriate (e.g., use of the 3 highest of 5 years as used under CSAPR), and if so, why?

   ii. Please comment on EPA's legal argument that they must use 2012 as a baseline.

   iii. Does 2012 represent normal operating conditions?

   iv. Please provide your estimate of the amount of reduction due to actions between 2005 and 2012 that have not been included in the goal setting for our state, and the cost of those measures since 2005.

   WPS Response: The establishment of the state goals excluded out of state renewables. WPS invested approximately $234 million in the 99 MW Crane Creek wind facility located in Iowa, which generated 315,656 MWh in 2012.

   Please see Wisconsin Utilities Response for responses to items i. - iii.

b. **Building Blocks.** Is the building block approach to setting state goals appropriate? Do you favor an alternative approach? Should states be allowed to propose alternative building blocks based on technical and economic feasibility when preparing a plan? Did EPA use the best data for Wisconsin power plants and power sector (renewable energy and energy efficiency) programs? For each of the building blocks below, please discuss any alternative approaches EPA could take.

i. **Building Block 1: Heat Rate Improvements.** This block calls for an overall 6% improvement in the heat rate of coal units.

1. Can Wisconsin's coal plants achieve a 4% improvement in heat rate on average through best practices? Can they achieve 2% improvement through equipment upgrades? If not, by how much could WI coal plants improve their heat rate?
   Please see Wisconsin Utilities Response.

2. What costs and timeframes would be needed to implement these heat rate improvements?
   Please see WPS response to question II b. i 6.

3. Should the goal be based on what is achievable on average across the nation or be more focused regionally or within a state?
   Please see Wisconsin Utilities Response.

4. Does EPA adequately consider possible interactions with Building Block 2 (increased dispatch of NGCC units) in determining what is achievable for heat rate improvements? For example, could decreased reliance on coal offset any benefit of efficiency upgrades because of reduced heat rate when a unit is run less or cycled more often, and by how much?
   Please see Wisconsin Utilities Response.

5. In calculating the goals, EPA assumes power plants can achieve all of the heat rate improvements by 2020. Is this feasible for Wisconsin units, or should EPA assume units can accomplish these improvements over a longer time period (e.g. by 2030)?
   Please see Wisconsin Utilities Response.

6. **For utilities: please identify any heat rate improvements** made since 2005 and provide specific cost and percentage change in heat rate for each unit.

   WPS Response: Each of the WPS units has been subject to asset life cycle management based on maintaining unit performance for the duration of operation required to satisfy WPS generation needs. The major equipment for each unit is covered by a life cycle management which optimizes performance and expenses within the rate structure approved by the PSCW. Overall WPS had been very successful at maintaining performance of generation assets without material impacts to electric rates. By virtue of this success the argument can be brought forth that improvements in O&M

will be hard pressed to result in 4% improvement in heat rate above current performance levels. Through current maintenance practices WPS is already realizing the "cost effective" improvements through O&M best practices.

Going forward the only unit that is a candidate for a major investment in efficiency improvement is Weston 3. Weston 4 is a relatively new efficient unit given it is a super critical unit. Pulliam 5&6 and Weston 1 are scheduled for retirement by June 2015. Weston 2 will convert to natural gas operation so it will have a low load factor making it a poor candidate for a heat rate improvement. Pulliam 7&8 have an uncertain future so they are not a good candidate for a major investment in efficiency improvements.

WPS's initial estimate is that the cost to increase Weston 3 efficiency by 4% would be approximately $65 million in capital investment. This estimate is derived from the Columbia CAMP project. Given the need for a Certificate of Authority, a project of this scope would take multiple years to permit, design and construct.

Please refer to Attachment A for a more complete discussion of WPS's position with regards to the heat rate improvement goal.

7. **For utilities: identify any heat rate changes from emission control projects** and provide specific cost and percentage change in heat rate for each unit. Discuss whether these changes are considered in the baseline.

   WPS Response: WPS is currently in the process of installing the ReACT emission control system on Weston 3. Once the ReACT system is installed WPS expects a 3.2% increase in full load heat rate for Weston 3. Given the EPA used 2012 data in its base line, and the ReACT system is still under construction, the EPA could not have accounted for the increase in heat rate due to the ReACT system.

ii. **Building Block 2: Increased Dispatch of NGCC Units.**

1. Can the state's NGCC units operate at 70% capacity on a permanent basis? What are the equipment impacts and O&M costs of operating at 70%? What are the impacts on the electric system? Will decreasing the ability to quickly ramp up/down adversely affect intermittent renewables on the system? **Please see Wisconsin Utilities Response.**

2. Is this building block likely to create electrical reliability issues if NGCC capacity isn't available for increased dispatch upon demand? Would

operating NGCC units at 70% capacity affect utilities ability to maintain the required 15% reserve capacity for reliability purposes?
Please see Wisconsin Utilities Response.

3. Was EPA's determination that existing natural gas infrastructure could support such an expansion adequate? If not, how much additional capacity is needed and is firm gas available? Please comment on natural gas storage and hedging impacts.

   WPS Response: This is highly dependent upon both the amount of CC capacity required as well as the location of where it is added on the system. The current infrastructure for both storage and transportation is designed around current conditions. Any increased supply for these products will lag demand creating price pressures until a balance is found. There is no requirement for firm gas and the need to have firm gas will largely depend upon the gas infrastructure sourcing the given unit. To ensure availability, utilities would likely be forced to acquire firm gas supply and storage, which would be costly. If new infrastructure is required (gas or storage), these costs will also be paid for by the generator. These costs will vary by specific location and will be charged via long term contracts, the length of which will be dependent upon costs (high cost for infrastructure will require longer terms to ensure costs are recovered).

   Attachment B shows the calculation of annual firm gas service cost assuming a new 500 Mw combined cycle unit is located adjacent to an existing ANR pipeline. The cost of firm transportation service, storage and no notice service is estimated to be $12 million/year. This estimate is based on the assumption that the ANR firm service tariff rates would double due to the need to make additional investment in the pipeline system in order to deliver firm gas service to a new 500 Mw combined cycle unit. In addition, investment in a natural gas lateral would be required to connect a new 500 Mw combined cycle unit to the pipeline system. For a 500 Mw combined cycle unit the interconnection cost alone could be $2 to $3 million with the 12 inch pipeline costing approximately $2.5 million/mile.

   With high gas usage for the CCs, utilities can actually purchase volumes of forward physical gas while still having a certain amount of financial derivatives. In other words, derivative programs may increase for CCs, but potentially not as much as one might think as a portion of gas can be purchased via physical purchases if there is consistency in unit capacity factors. The wildcard is the use of gas in CTs. With higher variable dispatch (cannot plan when they will get picked up), utilities will have to hedge the gas for the CTs via derivative programs, so the overall volume of these programs will sizably increase (assuming most of the purchase power is also gas based).

4. EPA suggests that states could drive these changes in dispatch via either economic mechanisms (e.g., a carbon price on electricity generation) or via emissions limits in permits. Which mechanism do you think would be most effective? What are the strengths and weaknesses of each mechanism?

   WPS Response: Economic mechanisms will insure that the re-dispatch of coal and combined cycle units will be done at the lowest cost. Permit emission limits cannot anticipate the most economic times that coal units should be dispatched. Market prices vary throughout the year and are a function of fuel prices, unit availability, transmission constraints, and system load level. Only the economic mechanism can adjust to market information in real time.

   The generation owner has to perform sophisticated optimizations to determine when the best time is to operate the generating unit to maximize market revenue while simultaneously remaining within CO_2 limits and yet have energy available to reliably serve load during system emergencies, especially those occurring later in the compliance period.

   The economic mechanism needs transparent and liquid CO_2 credit and offset markets which sets the price for CO_2 in real time. This information is needed so that the ISO market monitor can confirm that a generation owner's bid is reasonable and that market manipulation is not occurring.

5. In calculating the goals, EPA assumes power plants can increase NGCC dispatch to 70% by 2020. Can Wisconsin units fully ramp up dispatch by 2020, or should EPA allow units to shift dispatch over a longer time period? **Please see Wisconsin Utilities Response.**

iii. **Building Block 3a: Dispatch of At-Risk Nuclear Capacity.**

1. Is it appropriate and meaningful for EPA to count 5.8% of Point Beach's generation as "at risk"? Is this methodology reasonable, and if not, is there another approach you would propose to consider nuclear facilities? How

would this approach impact a non-regulated, merchant-owned plant like Kewaunee?
Please see Wisconsin Utilities Response.

2. How does this effort to keep "at-risk" nuclear plants open interact with licensing requirements which may require the plants to close at a certain date? For example, Point Beach's units are licensed through 2030 and 2033.
Please see Wisconsin Utilities Response.

3. Should EPA include other existing nuclear generation (e.g., the remaining 94.2% of Point Beach's generation) in setting the goal? If so, how?
Please see Wisconsin Utilities Response.

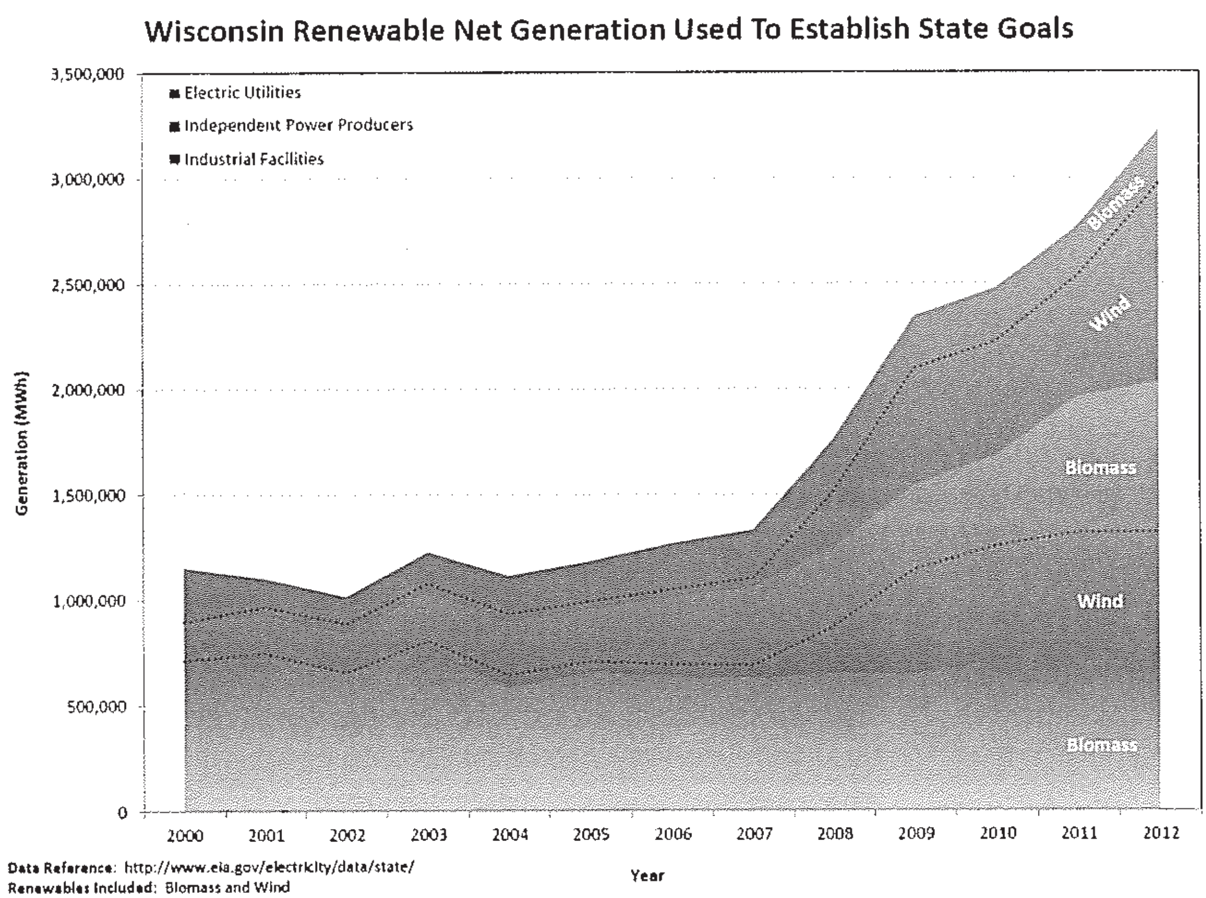
iv. **Building Block 3b: Increased Generation of Renewable Energy.**

1. Is it possible for Wisconsin to expand renewable generation to 11% of total generation with only in-state resources, and if so, what is the estimated cost of doing so? Is this achievable using a combination of in-state and out-of-state renewable energy purchases (which EPA intends to allow), and what are the likely costs of complying? How close are utilities to reaching the 11% goal if the requirement was for in-state resources?

WPS Response: WPS continues to support renewable resources, but are cautious regarding the level of expansion that would be needed for EPA's proposed rule.

Wisconsin's ability to meet the 11% renewable generation goal could be greatly impacted by the composition and size of its 2012 renewable base. A large portion of the renewable generation assumed by EPA in the proposed rule for Wisconsin was generated by non-utilities, such as independent power producers (IPPs), combined heat and power (CHP), and other industrial facilities, which may not ultimately be included in the State compliance plan. The Energy Information Administration (the source of EPA's data) reports Wisconsin's total in-state non-hydro renewable generation as 3,223,178 Megawatt Hours (MWhs) in 2012, of which 1,665,600 MWhs (52%) are from biomass resources. The definition of biomass under the proposed rules is up for debate, so there's no guarantee that these MWhs would be considered as generated from an eligible resource. In addition, approximately 640,000 MWhs or 32% (of the ~1.6 Million total) of biomass generation was from behind the meter facilities owned by industrial customers. All are tied to older paper pulping facilities and any reduction from those facilities would need to be replaced by new sources, making the interim and final reduction goals that much harder to meet.

Renewable generation from these types of behind the meter facilities is not growing. The following figure shows the breakdown in renewable generation by ownership based on EIA data from 2000 – 2012. Regardless of ownership, EPA applies a six percent growth factor to all Wisconsin renewables from 2017 onward.



On the other hand, EPA did not include electricity from small (<1 MW) distributed generation (DG) in the baseline calculation. WPS does not have an efficient way of determining statewide annual DG generation totals. The Public Service Commission could probably estimate DG's contribution toward the goal using data from the annual RPS reporting system.

In calculating Wisconsin's proposed emissions goal, EPA projects a more than doubling of in-state renewable generation from 3.2 million MWhs in 2012 to 6.8 million MWhs by 2029. To help put that in perspective, Wisconsin had ~639 MW of utility scale wind generation that produced a little over 1.5 million MWh's in 2012. If Wisconsin chose to meet all of EPA's projected RE goals (2029 goal of 6.8 million versus 2012 3.2 million Mwh) with 28% wind it would need to nearly triple Wisconsin's wind generation capacity. The feasibility of siting, and integrating that much wind into Wisconsin's electric transmission/distribution system would be difficult to estimate with any certainty. Estimating the costs of complying with a combination of in-state and out-of –state renewable resources would be difficult as cost of transmission and availability of sites are unknown. In summary, reaching the 11% RE goal with in-state resources is likely to be challenging both technically and economically.

2. Is it appropriate for EPA to exclude out-of-state renewables in setting a state's goal? If it is not appropriate, can you suggest a mechanism by which EPA could account for the many different contracts for renewable electricity purchases across state lines?

   WPS Response: There are a number of problems with the baseline renewables used by the EPA in its goal-setting calculation. As noted, the EPA excluded out-of-state renewables. This is particularly a problem for Wisconsin, since a significant portion of the renewable portfolios of the state's utilities are located in other states. In addition, some states have better renewable availability - for example, both Iowa and Minnesota have high wind speeds on average. In summary WPS believes that if a renewable resource is eligible for Wisconsin RPS compliance, and a Wisconsin electric customer pays for it, they should receive credit for <u>both goal setting and compliance</u> purposes.

   The use of a renewable energy tracking systems – such as the Midwest Renewable Energy Tracking System (M-RETS) – could provide a mechanism to account for the purchase and sale of renewable energy across state lines.

3. Is it appropriate for EPA to determine the target and growth rate on a regional basis? Are there other ways (state-specific, nationally, based on technical renewable generation potentials) that would be better?

   WPS Response: EPA's determination of regions for renewable energy goal setting was arbitrary, using RTO & NERC regions as a general guide. EPA used the average RPS requirement of the <u>five states</u> with an RPS requirement in their <u>nine State</u> "North Central Region" to arrive at a 15% "Effective RE level"(76/5). EPA concludes that states in the same region have similar renewable energy potential, as measured by existing renewable energy standards adopted by some states in the region. This is a false conclusion as Wisconsin does not have the same wind resources as those states to the West and has faced opposition to wind development in some areas.

Therefore, the EPA's regional basis is not the best approach. At a minimum, the EPA's proposed approach should factor a zero into the regional calculation for states without an RPS. It should also factor in an estimated amount of renewable generation as a percentage of retail for those states with a renewable capacity mandate (such as Iowa).

State	2020 Effective RE Level (%)
Illinois	16%
Indiana	
Iowa	
Michigan	10%
Minnesota	30%
Missouri	10%
North Dakota	
South Dakota	
Wisconsin	10%

4. Is the use of state Renewable Portfolio Standard targets appropriate for a regional goal?

   Please see Wisconsin Utilities Response.

5. Is it appropriate for EPA to apply a growth rate that is a percent of existing capacity?

   WPS Response: The growth rate used by EPA is simply the result of a calculation designed to get the region as a whole to its prescribed renewable energy target by 2029. The annual growth rate (6%) is then applied to the State's 2012 renewable levels beginning in 2017. There are several problems with this approach including but not limited to: The ability to integrate new renewable generation into transmission and distribution systems. The availability of renewable generation sources due to supply/demand limitations. Last but not least, critical path limitations related to obtaining regulatory approvals.

The following charts are meant to illustrate how uncertainty, as to what would be included in Wisconsin's baseline, could impact its ability to reach EPA's proposed renewable energy goals. For example in CHART-A, the 2012 EPA established baseline included biomass facilities from all sectors. It demonstrates the needed growth rate (demonstrated as new wind generation) should all biomass be excluded. While the exclusion of all biomass for compliance purposes is unlikely, it is uncertain how biomass will be treated in the compliance phase. CHART-B demonstrates the needed growth rate should all biomass included in the baseline be allowed for compliance.

CHART-A

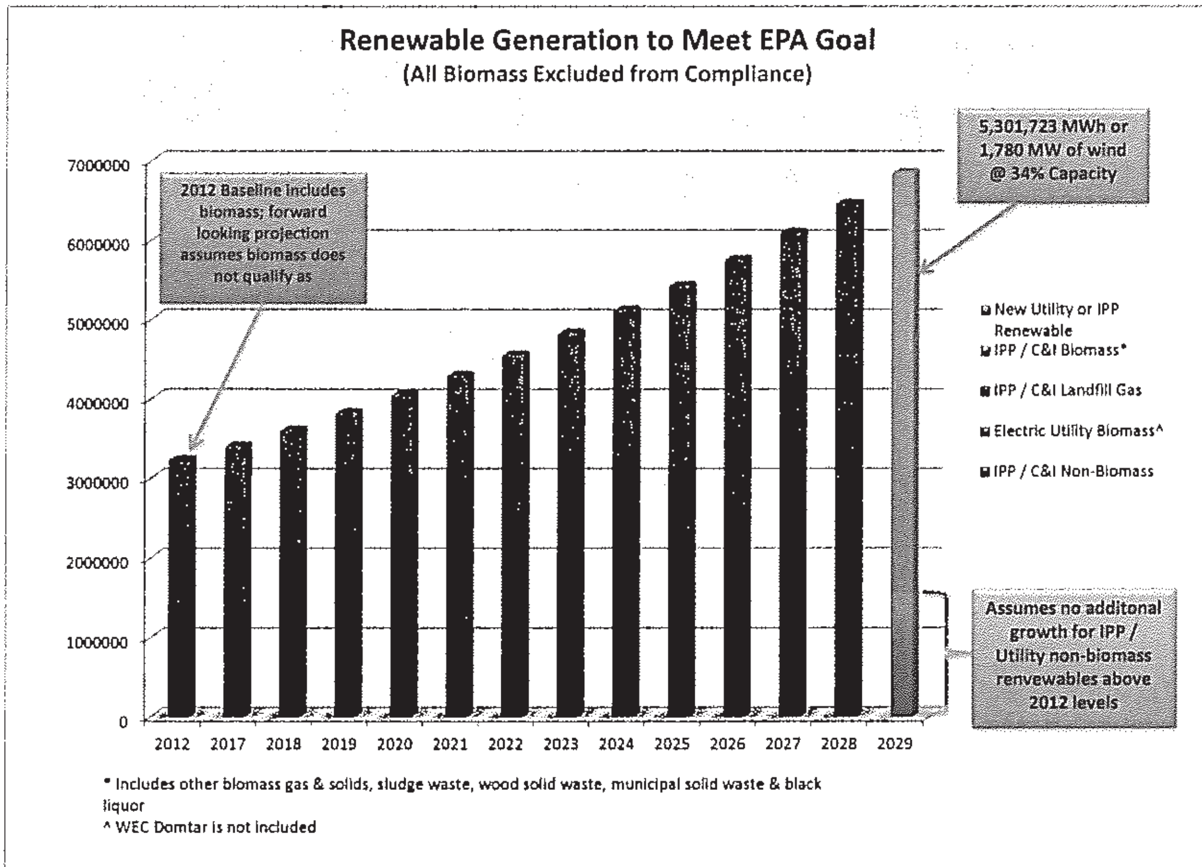
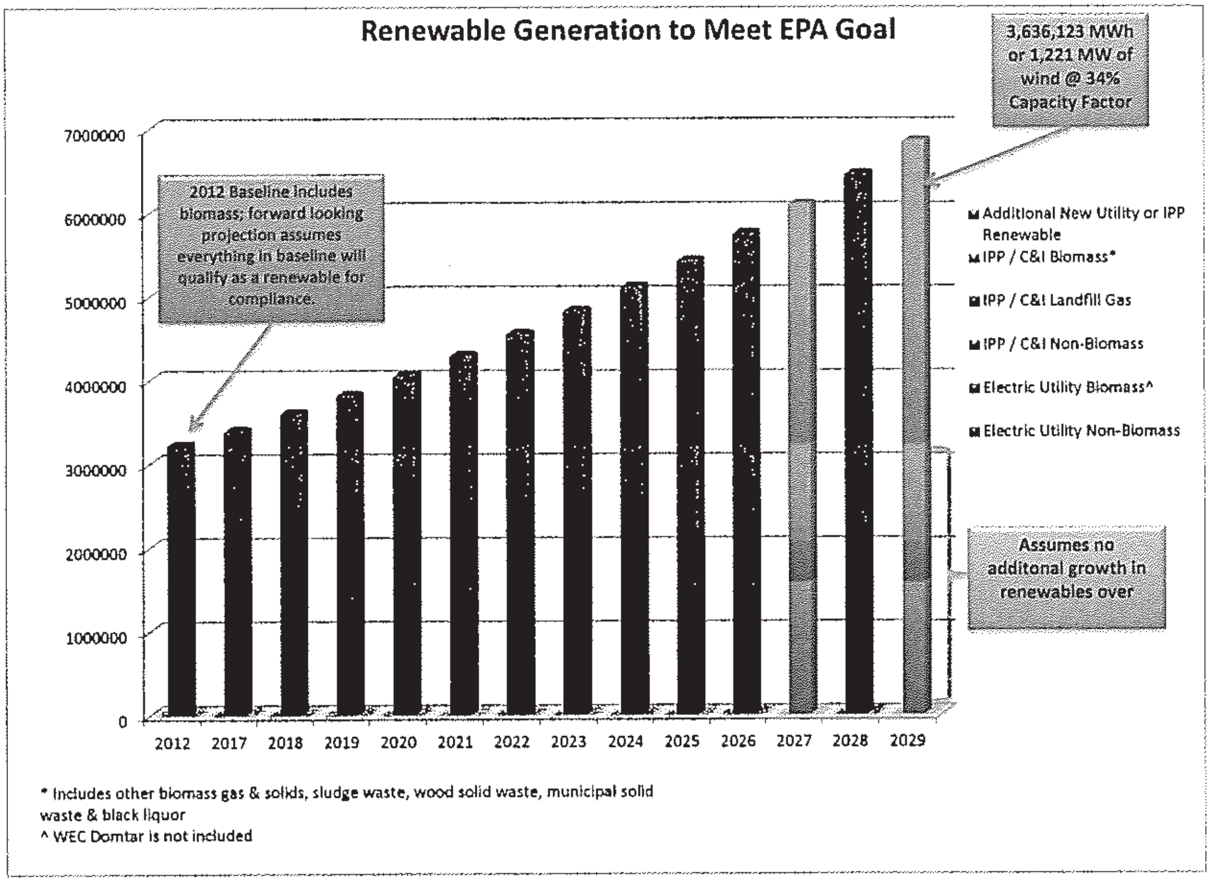


CHART-B



6. EPA describes an alternative renewable energy approach based on technical and market potential for renewable energy within different states. Do you believe this is a better approach? Do you agree with how they calculated renewable energy potentials? Please discuss why or why not. What would this mean for Wisconsin, specifically? Would an approach that is based on potential within in a state rather than RPS goals consider current or future out-of-state obligations?

   WPS Response: EPA's "Alternative Renewable Energy Approach" uses a top down technical potential process in combination with an Integrated Planning Model to inform state renewable goal targets. The net result for Wisconsin appears to be a ~600,000 MWh increase in renewable energy added to its renewable energy target. This approach fails to consider the same limiting factors as that of the regional RPS formula: The ability to integrate new renewable generation into transmission and distribution systems. The availability of renewable generation sources due to supply/demand limitations. Last but not least, critical path limitations related to obtaining regulatory approvals.

v. **Building Block 4: Increased Energy Efficiency.**

1. Is it achievable for Wisconsin to sustain 1.5% incremental savings per year through 2030 and beyond? If so, should it be done through the Focus on Energy program or via some other means? If 1.5% incremental savings is not achievable, is there a different target that would be more appropriate?
Please see Wisconsin Utilities Response.

2. Is the growth rate of 0.2% of sales per year appropriate? If not, what is the appropriate growth rate?
Please see Wisconsin Utilities Response.

3. Is EPA's choice of measure lifetime (used to define the duration of energy savings) for the goal appropriate?
Please see Wisconsin Utilities Response.

c. **Alternative Approaches Discussed by EPA.**

i. EPA presents alternate targets for each building block that are less stringent and have shorter compliance periods. Please comment on each of these targets and whether you believe they are more or less appropriate than those proposed by EPA.
Please see Wisconsin Utilities Response.

ii. EPA also discusses a different approach to setting the goals based on Building Block 1 (heat rate improvements) coupled with reduced utilization of fossil EGUs. Do you believe this is a better approach? Please discuss why or why not.
Please see Wisconsin Utilities Response.

III. COMPLIANCE WITH THE RULE.

a. **Compliance Flexibility.** Do you have any concerns with the compliance flexibility proposed in the rule? Are there other flexibilities that should be considered (e.g. use of CHP, non-electric energy efficiency, etc.)? If EPA allowed too much flexibility, how could they narrow the scope of what is allowed for compliance?
Please see Wisconsin Utilities Response.

b. **Responsible Parties.** EPA says this rule should allow states to comply via either an emission limit approach (in which limits are applied to units which may or may not be able to

purchase and trade credits) or a portfolio approach (which may combine emission limits with other enforceable measures and may be utility-driven or state-driven). Does anything in the rule as written preclude the use of any of these approaches? Which parties (utilities, states, etc.) should bear the obligation for the different aspects of compliance?
Please see Wisconsin Utilities Response.

c. **Rate and mass based standards.**
    i. Does the rule structure adequately allow for use of either a rate or mass based standard? If not, how could the rule be modified to do so?
    ii. EPA does not prescribe a methodology for determining mass based limits. What factors should be considered in establishing a mass cap?
    iii. EPA presumes that states may establish mass caps when developing a plan. Should these values be fixed or be adjustable going into the future?
    iv. Should EPA determine mass caps for each state? Should states be required to use EPA's determined limit or allowed to calculate their own mass cap (subject to EPA approval)?
    v. Would it be appropriate and feasible for Wisconsin utilities to adopt different approaches such that one utility could comply with a mass-based standard while another meets rate based goal?

WPS Response: The choice between a "rate" or "mass" limit is a function of how firm the EPA wants to be on achieving a 30% reduction from 2005 CO_2 emissions by 2030. If the 30% reduction is not a firm goal then the "rate" limit can truly allow for growth and may be preferred over the "mass" limit. If the 30% reduction is a firm commitment, it would seem that the "rate" approach in fact cannot allow for growth at a national level and issues like accounting may favor the "mass" limit.

WPS suggests that instead of limiting comments to a request that EPA clarify the procedure to be used to convert the CO_2 target rate to a CO_2 mass limit, the EPA be asked to provide specific state CO_2 mass limits in the final rule. Since the stated goal is to reduce the 2005 CO_2 emissions from affected units by 30% in 2030, the sum of the state CO_2 mass limits should sum to 70% of the 2005 CO_2 mass emissions. The only potential area of disagreement would be the allocation between states, since each state's share of the total United States emissions was likely different for 2005 compared to 2012, which is the year EPA used to apportion state-by-state emission reductions. To address this concern, a mass limit for each state could be developed by comparing a 3 year average ratio of the individual state's CO_2 mass emissions to the national total. This ratio could then be applied to the national 2005 CO_2 mass emissions and then reduced by 30%.

Under a mass limit, new units should not be part of the existing unit rule when the new units come on line, as they will be covered under the new unit standard emission rate limitations.

In its current emission rate form the rule relies on modeling of long term Mwh generation from the state's generating units. Long term forecasts are uncertain and are dependent on a number of factors such as load growth, market prices, unit availability and the particular model selected for the forecast. This uncertainty would result in the state not knowing whether or not the EPA will approve the state's conversion of the CO_2 rate to a mass limit until after the state has filed its implementation plan. Also, since the state specific CO_2 rate is a function of the assumed state specific renewable energy and energy efficiency targets, there is the potential for arguments being made about the equity of the assumed levels of renewable and energy efficiency targets. States with more aggressive renewable and energy efficiency targets could raise the issue of whether or not their target CO_2 rate is "fair" compared to those states which have less aggressive renewable and energy efficiency targets.

If an emission rate based limit is employed, new units could be added to the emission rate calculation as they come on line.

As a practical matter, no matter whether a "rate" or "mass" limit is employed and no matter what conversion method might be used to go from a "rate" limit to a "mass" limit, at the end of the day EPA will be monitoring actual CO_2 emissions. If the actual CO_2 emissions do not track toward the "30% reduction from 2005" a "do over" will likely be considered for the state implementation plans.

The final rule should include off ramps which could take the form of relaxed CO_2 mass limits. These off ramps could be utilized in the event of either a reliability issue or economic hardship.

WPS can see Wisconsin developing a "no energy efficiency" CO_2 rate for the utilities where the "no energy efficiency" CO_2 rate does not include the energy efficiency Mwh in the denominator. The energy efficiency compliance component would than been given to an organization like Focus on Energy to achieve. The utilities would use the "no energy efficiency" CO_2 rate in developing plans to meet the rate through heat rate improvement, re-dispatch, and renewable energy. It would be reasonable for the state to establish a utility specific "no energy efficiency" CO_2 rate recognizing the unique attributes of each utility.

Once the state sets out to calculate a utility specific CO_2 rate or CO_2 mass limit, there is the potential for the creation of winners and losers which would precipitate a contentious regulatory process. The creation of winners and losers is driven in part by the uncertainty associated with forecasting generation in the long term at the individual utility level, assuming the allocation would be based on future need. Also, the treatment of utility specific coal/combined cycle mix of generation as it impacts the allocation of the rate or mass limit is also a contributing factor. The allocation has to account for the different unit mixes in order to assure a fair allocation of the CO_2 reduction. It appears that converting the state limit to a utility specific limit will be more problematic than the comingling of utility specific CO_2 rates and CO_2 mass limits.

d. **Use of new facilities for compliance**. EPA states that it intends to allow new units (such as new NGCC plants) to count towards compliance with the existing source rule. Do you see any potential issues with regulating these plants under both 111(b) and 111(d)?
Please see Wisconsin Utilities Response.

e. **Expansion of renewables**. For utilities: how much additional renewable generation and what type do you anticipate using to comply with this rule? Are you likely to build this capacity in state or out-of-state? Please provide any costs estimates, if you have them, for this additional capacity, whether it is generation or transmission costs.

WPS Response: Following the EPA lead, WPS developed an "algebraic dispatch" model. This model does not account for the fact that generation has to balance with load on an hourly basis, accounting for operating constraints and security dispatch, the results from such models must be used with caution. In addition, no attempt has been made to confirm whether or not the level of combined cycle, renewable or energy efficiency development needed for compliance with the proposed CO_2 rule is achievable in Wisconsin. With those caveats WPS evaluated from a state perspective what order of magnitude effort would be required to bring Wisconsin into the 1,203 lb/Mwh target starting with the 2020 system data that the Wisconsin utilities filed in November 2013.

Assuming the Wisconsin system is re-dispatched so that existing (as of 2020) combined cycle units are operated at a 70% capacity factor and Wisconsin does not import or export power, the Wisconsin CO_2 rate target (1,203 lb/Mwh) can be achieved by increasing one of the following: 1. New combined cycle capacity, 2. Wind generation, or 3. Energy efficiency:

Action Taken To Reduce CO_2 Rate	Extent of Action Taken	Comments
Add new combined cycle units	Add 3,000 Mw of new combined cycle capacity	Can retire up to 3,000 Mw of coal capacity without impacting Wisconsin reserve margin. Retiring 3,000 Mw of coal capacity will preserve higher capacity factors for coal units
Add new wind units	Add 3,300 Mw of new wind generation [As an alternative to 100% wind, Wisconsin could purchase 300 Mw from Manitoba Hydro which is assumed to have a higher capacity factor then wind generation. 300 Mw of Manitoba Hydro is equivalent to 500 Mw of wind so Wisconsin would need 2,800 Mw of wind (as opposed to 3,300 Mw) if Manitoba Hydro is included.]	Due to the amount of wind needed, it is expected that most of the wind will be out of state (outside of Wisconsin capacity zone) and since wind does not contribute much capacity to the reserve margin calculation, no coal units can be retired without reducing Wisconsin reserve margin. Wisconsin coal units would be operating at a 40% capacity factor.
Increase energy efficiency beyond historic levels of energy efficiency which is embedded in current forecasts	Reduce sales by 15%	Can retire up to 1,300 Mw of coal capacity without impacting Wisconsin reserve margin assuming demand reduction is 50% of energy reduction.

The previous table shows how much combined cycle generation, wind generation "or" energy efficiency is needed to comply with the Wisconsin CO_2 rate, if each resource is solely relied upon for compliance. If Wisconsin were to comply with a balanced approach, relying on new combined cycle units, renewable and energy efficiency, Wisconsin could comply with the CO_2 rate using the following mix of resources:

New combined cycle units:	1,000 Mw
New wind generation:	1,300 Mw
Reduce Wisconsin sales by:	4%

Based on CAPEX it is estimated that the major network upgrade to accommodate expanded wind generation in the Dakotas is approximately $500/kw. Coupled with that is the transmission investment to connect the wind farms to the network estimated to cost approximately $300/kw. The total transmission cost for Dakota wind farms is $800/kw.

Dakota wind generation (generation cost only) is estimated to cost $2,360/kw. NREL 2013 Wind Technologies Market Report – "Interior" region generation cost for 2012/13 is $1,760/kw (page 52). On page 49 of same report shows installed cost came down $600/kw from 2009/10 to 2012/13 due to reduced market demand in 2012/13. Given the entire country will be trying to comply with CO_2 rule it is reasonable to assume demand for wind projects will drive up project costs.

It is important that out of state renewable energy is allowed to be used for compliance. This will assure the most economical approach can be used to meet the CO_2 limit.

f. **Interstate effects - RE.** EPA states that renewable electricity purchased from out-of-state could count towards compliance if the states ensure that this electricity will not be double counted. Is this appropriate? Can you suggest any way to structure the program to ensure that such electricity is not double-counted?
Please see Wisconsin Utilities Response.

g. **Interstate effects – EE.** EPA proposed to scale down energy efficiency savings for states that are net importers of electricity and took comment on whether they should scale up EE savings for net exporter states to account for the cross-border savings from in-state programs. Are these each appropriate approaches? Is there a better way to handle this issue?

WPS Response: As a general comment, the proposed rule relies heavily on modeling for forecasting implementation plan compliance, backcasting to demonstrate compliance and assigning CO_2 credits to RE and EE projects. The final rule should reduce its dependency on modeling because of the uncertainty inherent in forecasts, which are used in models, as well as the approximations that are made in modeling algorithms.

Assigning CO_2 credits to RE and EE requires modeling to determine on a regional level exactly how much CO_2 reductions are achieved by a given RE or EE project. The calculation of avoided emissions is a very complex, uncertain, and nontransparent process, subject to challenge.

To avoid double counting CO_2 credits, the ISO would have to calculate after the fact the change in emissions on all of the generating units that are impacted by renewable generation and then the ISO would have to determine how much CO_2 credits are assigned to the RE/EE projects and concurrently has to inform the generation owners how much CO_2 credits have to be deducted from its credit balance. This true up has to be done on a frequent basis so that the generation owners are made aware of any changes in their CO_2 positions due to RE/EE. This is a very complex problem.

A better approach is to pattern the rule after other Clean Air Compliance programs, namely express the CO_2 limit in terms of a mass limit which is allocated for the affected units. Let the states develop RPS/EE mandates to reduce the fossil generation requirements in order to stay under the CO_2 mass limit. Another approach would be to establish CO_2 and offset markets which could be used to establish the CO_2 cost which then would be included in the generator's bid and which ultimately would be monetized in the market price which would further incent the development of RE/EE.

h. **Trading program.**
   i. EPA allows states or regions to create plans based on emissions averaging and trading. Is this appropriate?
   ii. Should EPA provide a default national trading program that states or sources can opt into for compliance purposes?
   iii. Are there types of credits or trading programs that may be barred from the rule as proposed?
   iv. Would it be appropriate to have separate systems for trading pounds of CO_2 and avoided megawatt-hours of generation?
   v. Should a trading program be state-wide, region-wide, or nation-wide?
   vi. Who should manage emission trading systems?

Please see Wisconsin Utilities Response.

i. **Displacement of generation/emissions.** EPA does not specify a methodology for states to use in determining what kind of generation (and how large its associated CO_2 emissions) would be displaced by renewable electricity and energy efficiency measures. What would be the best way to determine this?

WPS Response: In a rate-based system, accounting for renewables and energy efficiency will be challenging.

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j. **Federal enforceability of compliance measures.** If a program is explicitly used as a compliance measure under this program, EPA has stated that that program must become federally enforceable. Do you foresee any issues with having existing state programs (such as the RPS and Focus on Energy) become federally enforceable?

   WPS Response: Yes. The mechanism by which the State imposes federally enforceable conditions on a facility such as a power plant is through the air operating permit. Most facilities generating renewable energy (other than biomass) typically do not have air permits. Focus on Energy efficiency programs are even further removed from the permit process. Although EPA could find that a State has not met its obligations under an emission rate based compliance system, it is extremely unclear through what mechanism, in lieu of an air permit, the State could use to proceed with an enforcement action against a renewable energy provider or against Focus on Energy. Presumably, some type of legislation would be needed to obtain this enforcement authority. Further, since the incremental improvements available from increased energy efficiency become significantly more expensive to attain after the low hanging fruit has been picked, energy efficiency programs goals may be unattainable and Focus on Energy will not be interested in being subject to enforcement if EE goals are not met.

k. **Regional approaches to compliance.** Do you have any thoughts on whether Wisconsin should participate in a regional compliance approach? What type of regional approach would be most appropriate? Which other states would you like to see as partners?
   Please see Wisconsin Utilities Response.

l. **Treatment of biomass.** EPA stated that they assume states will use biomass for compliance with the regulation, but also referred to their not-yet-released biomass accounting framework when discussing how biomass would be treated under this rule. How should biomass be treated? Should different types of biomass-based generation be treated differently? For example, should agriculture digesters receive credit for methane reduction as well as for displacing carbon emitting generation?

WPS Response: Biomass eligible for State RPS requirements should be eligible for 111(d) compliance purposes. Methane reduction from agricultural digesters and landfills should be discussed. Burning or "flaring" methane alone under 111(d) is not recognized as a CO_2 reduction mechanism. Only methane used to generate electricity would be recognized. The destruction of methane (or more specifically thermal oxidation of methane to CO_2) from these sources materially reduces the amount of heat trapping capacity in the atmosphere through conversion of methane to CO_2. . This is probably more of a legal/regulatory issue than a technical one in terms of regulation which can be promulgated under the Clean Air Act.

IV. OTHER TOPICS.

a. **Potential to trigger New Source Review requirements.** Do you agree that sources undertaking efficiency improvement projects under 111(d) should not trigger NSR permitting requirements for criteria pollutants? Can you provide any technical or legal analysis or justification for why sources complying with the state 111(d) plan should not (or should) trigger NSR permitting requirements?

WPS Response: Yes. We would agree that a change (modification) needed because of a regulation change should not subject a facility to additional permitting. As the rules stand today, we are unaware of a technical or legal argument to support this position, as there are no current exemptions that are based on the "intent of" or the "motivation for" the change (modification). As the regulations currently stand, tripping the emission increase threshold, triggers permitting.

b. **Permit interaction under multiple federal rules.** Do you have concerns about how the different requirements under different rules (i.e., the CO_2 NSPS, the modified and reconstructed source proposal and the existing source proposal) interact for permitting purposes? How should EPA and WDNR handle these interactions?

WPS Response: Yes – we have concerns. During a recent project concerns arose over differing interpretations, or differing definitions of key criteria used for applicability determinations (e.g., the definition of a "facility," an "affected source," what constitutes a "reconstruction") between the various rules. The definitions don't always matchup between the rules which leads to either loopholes or pitfalls in the permitting process. Lack of clarity in the permitting process is not helpful for either a facility or for the WDNR. WDNR should comment and EPA should correct any inconsistencies between rules to ensure that all aspects of rule definitions are consistent.

V. MODIFIED AND RECONSTRUCTED SOURCE PROPOSED RULE.

a. **BSER.** The baseline for modified steam boilers and fossil fuel gasification units is based on each unit's best historical annual emission rate plus an additional 2% emission reduction. Is this an appropriate baseline? Should EPA use an averaging period in determining a historic emission rate? Is it reasonable to require an additional 2% emission reduction?
Please see Wisconsin Utilities Response.

b. **Proposed emission limits.** Are the emission limits that EPA proposes for modified and reconstructed units appropriate?
Please see Wisconsin Utilities Response.

Attachment A

Date: August 26, 2014

Subject: Clean Power Rule – Heat Rate Improvement WPS Review

Clean Power Rule – Heat Rate Improvement

The EPA announced on June 2, 2014 the Clean Power Rule and is accepting comments until October 16, 2014. The intent of this white paper is to develop a WPS position for the BSER (best system of emission reduction) building block 'heat rate improvement' for WPS's coal fired EGU's to submit as comment. There are many concerns with the Clean Power Rule but the focus of this paper is only on the basis of heat rate improvement as described in Technical Support Document (TSD) Docket ID No. EPA-HQ-OAR-2013-0602 and feasibility of implementing heat rate improvement tactics at WPS coal fired EGU's. The TSD describes the statistical analysis performed on heat input and generation data reported by utilities via 40 CFR part 75 requirements to substantiate the potential heat rate improvement goal of 6% across the entire US fleet of coal-fired EGUs. Basing the analysis on part 75 data ignores verification performed on this data prior to submitting which tends to adjust the data for emission reporting purposes not performance evaluation purposes. In addition, the statistical processes utilized to 'standardize' the data can introduce variances which impact evaluating performance of the coal fired EGUs. Review of the statistical analysis is not included, but reviewing the goal and factors that affect heat rate is to help establish a WPS position.

EPA states the 6% improvement heat rate goal is technically feasible but at the same time asserts it is not possible to determine if all of the presented improvement items are available to effect the change. As stated on page 2-36, "...EPA expects that a significant fraction of the coal fleet has already applied some or many of the available HRI methods." The goal is a summation of EPA's estimate of improvement gains through operational and maintenance (O&M) best practices (4%), and equipment upgrades (2%). O&M best practices are normally part of the life cycle management for EGU's thus additional gains in the range of 4% may overvalue an attainable goal. Heat rate improvement upgrades of equipment include economizer replacements, turbine overhaul and uprates, neural networks, boiler feed pump rebuilds, etc. Some of these upgrades are very costly and result in marginal improvement of heat rate thus pose challenging economics to justify the change. Both of these changes would normally be included in a life cycle management approach therefore if haven't been undertaken to date could mean the economics have not been attractive or there is a flaw in life cycle management. EPA's concession about whether or not improvement has been made represents a flaw in the assumption that 6% is obtainable by the existing coal fired EGU fleet.

The report enumerates several factors which impact heat rate and deserve some review in relation to the heat rate improvement potential of coal fired EGU's. The factors contained in the report are linked into the following categories:

- Original Design Basis

  - EGU thermodynamic cycle
  - EGU coal rank and quality
  - EGU size
  - EGU cooling system
  - EGU geographic location and ambient conditions
- Alterations
  - EGU pollution control systems
  - EGU plant components
- Operational Items
  - EGU operating and maintenance practices
  - EGU load generation flexibility requirements

The categories represent the ranking of the potential for the factors ability to be implemented in relation to improving heat rate. Items listed in the original design basis are least likely to be implemented due to cost and scope of change required to impact heat rate by an appreciable amount (described further below). Alteration items are more likely and represent items which could improve heat rate, but the items listed are usually opposed to each other. Changes in pollution control systems are regulatory driven and tend to increase auxiliary power usage which will degrade heat rate. Changes in plant components can improve plant efficiency and subsequently heat rate, but usually by slight incremental amounts. In addition, changes to plant components are normally not undertaken for improvement needs alone, but rather combined with addressing reliability issues with the equipment. Operational items are contained in life cycle management of the asset which all utilities implement to their own internal standards. EPA recognizes improvement factors are in place and states that more than once in the TSD. It should be noted generation flexibility requirements improve EGU utilization in energy markets but result in negative impacts on heat rate. For example the minimum load heat rate for Weston 3 is approximately 10% higher than the full load heat rate for Weston 3. This means if compliance with the EPA regulation requires shifting MWh generation from coal units to combined cycle units, then it should be expected that coal unit average heat rate will increase as a result of the re-dispatch.

Improvement in the original design basis category may have the most impact to improve heat rate but implementing changes to these items represents the biggest challenges. At question here is improvement in thermodynamic design basis of EGUs. Each unit's design basis was optimized to meet the requirements at the time the need for more generation was sought. Locational needs, size needs, and fuel source availability are inputs into the thermodynamic design of each EGU. Making changes to these attributes are challenging and not undertaken unless there is an external need or the ability to improve has increased since the original design date of the EGU. Improvements occur through advancement in knowledge and technology both in design capabilities and material science. The thermodynamic design basis (knowledge) is fixed by the configuration of the EGU therefore; improvement in heat rate is made in response to technology improvements. Improved technology through advancements of tools utilized in the design process and improvements in materials can be incorporated into the design. Depending on the age of the unit and previous improvements made a potential improvement in heat rate can be estimated.

The WPS coal fired EGUs subject to the Clean Power Rule are Pulliam units 7 & 8, and Weston units 3 & 4. Information on each unit is as follows:

Unit	Year of Service	Design Heat Rate
P7	1954	10,012
P8	1960	10,090
W3	1982	9,968
W4	2008	8,646

The Design Heat Rate information from original design documents is based on standard conditions. Each unit's operating heat rate will vary from low load to high load depending on design, material condition of the unit, environmental conditions and market based impacts. The variability of the heat rate is normal but is not adequately addressed under the Clean Power Rule to ensure consistent reporting between utilities. The statistical analysis of the Part 75 data did not correct to any standard conditions which in itself points to the issue with the goal for Heat Rate improvement.

Each of the WPS units has been subject to asset life cycle management based on maintaining unit performance for the duration of operation required to satisfy WPS generation needs. The major equipment for each unit is covered by a life cycle management which optimizes performance and expenses within the rate structure approved by the PSCW. Overall WPS has been very successful at maintaining performance of generation assets without material impacts to electric rates. By virtue of this success the argument can be brought forth that improvements in O&M will be hard pressed to result in 4% improvement in heat rate.

Over the operating history of the WPS EGUs equipment upgrades have been performed and contemplated to meet reliability needs and improvement in performance. Review of all past projects is not necessary since the performance of the EGUs has been properly maintained over the operating life to date. Several specific projects are worth noting in response to the equipment upgrades listed in the TSD.

Neural networks have been installed on both W3 & W4 and are actively utilized in a program to maintain EGU performance. The networks are monitored by an external party who routinely reports performance to WPS personnel and in tandem with WPS develops corrective actions. These efforts have resulted in accurate maintenance of unit performance and proactive management of issues that arise during normal operations. Additional improvements will be very difficult at W3 & W4. Installation of neural networks at P7 & P8 is not feasible due to significant cost to add instrumentation and monitoring needed for an effective network. In addition, investment of this nature is not in alignment with the life cycle management of P7 & P8 which are toward the end of operating utilization for the WPS generation fleet. P7 & P8 are monitored through testing programs which are routinely performed to ensure combustion control are maintained therefore, additional improvement in heat rate would need to be performed for reasons other than asset life cycle management.

An upgrade to the P8 turbine was contemplated in 2009 but not pursued due to unsatisfactory return on the investment as measured at that time. The upgrade consisted of changing major portions of the turbine design within the dimensions of the original unit. These types of projects are possible and have been successfully executed on other turbines similar to P8. The economics of the project did not provide the return needed to justify requesting approval for this investment from the PSCW which potentially could have disallowed the project thereby exposing WPS wholly to the investment risk. This is an example of the uncoupling between cost and benefit for heat rate improvement projects which challenges the practicality of the heat rate improvement goal.

Alliant's EGU Columbia Plant is pursuing a project that encompasses several of the improvement factors described in the TSD. The project titled "Columbia Asset Management Plan" includes a major upgrade of the steam turbine and pulverizers aimed at improving heat rate on both units 1 & 2 by approximately 4% (combined operating capacity increased for both units is 95 MW). The total cost of the project is $65MM per unit consisting of $37MM for steam turbine and $28MM for pulverizer upgrades. The improvement is estimated to cost $1,370/kW which is substantially greater than the cost indicated in the TSD of $100/kW. The justification for the CAMP project is made in reflection to the on-going emission improvement projects at Columbia units 1 & 2 which increased heat rate and decreased performance. Justification of CAMP alone would not have received PSCW approval, but since the result will return the losses due to the emission control projects approval was received from the PSCW and is proceeding. The codependency of the two projects at Columbia points to the dichotomy of the premise that heat rate improvement is feasible and justifiable as proposed in the Clean Power Rule. If a similar project were to be undertaken at W3 (in response to ReACT project) costs would be comparable to the Columbia units. WPS has not pursued a similar project at W3 at this time due to difficulties with justification of these costs in relation to overall investment in W3 life cycle management.

WPS's position regarding Heat Rate Improvement per the Clean Power Rule should be reserved, at this time, to disagreement with the assertion that 6% improvement is possible for all EGUs affected by the rule.

Attachment B

Fixed Costs for Firm Natural Gas Services

ANR Pipeline Company
500 MW Combined Cycle

Assumptions:

Capacity [1] - MW	500	input cell
Full Load Heat Rate [2] - Dth/MWh	7.000	input cell
Firm Transportation Service [3]	FTS-1	input cell
Max hours needed in one day	24	
Maximum Daily Quantity (MDQ) - Dth/day	84,000	
Maximum Hourly Quantity (MHQ) - Dth/hour	3,500	
MDQ /MHQ Ratio (FTS-3 ONLY)	n/a	
Days of Firm Storage	10	
Fuel Charge for Losses	0.91%	
No Notice Service Ratio to MDQ	0.333	
No Notice Sevice (NNS) - Dth/day	28,000	
No Notice MBS Service % of Max Daily	10.00%	

Calculations:

	Dth	Tariff	Annual $
Firm Transportation Service:			
FTS-1 MDQ	84,000	8.500	8,568,000
FTS-3 Delivery Reservation	0	4.250	0
FTS-3 Capacity Reservation	0	0.135	0
Firm Storage Service:			
Deliverability Reservation	84,771	2.450	2,492,280
Capacity Reservation	70,643	0.400	339,086
No Notice Service:			
MBS	8,400	6.250	630,000

Total Annual Fixed Costs

Firm Transportation Service	8,568,000
Firm Storage Service	2,831,365
No Notice Service	630,000
Total Firm Service Costs	**12,029,365**

Notes:

[1] Capacity rating should be based on when firm fuel is most needed. Winter typically has the highest rating for natural gas units.
[2] If combined cycle is duct fired, make sure full load heat rate incorporates the additional fuel requirements
[3] Firm transportation service is either FTS-3 (max 16 hours/day) or FTS-1 (baseload 24 hours/day)

The ANR firm gas service tariff prices were doubled to reflect the need to invest in pipeline capacity in order to provide firm service.