**MEMORANDUM**

**To:** Carbon Power Plan for Existing Power Plants; Docket id: OAR-2013-0602

**From:** Region 5, EPA

**Summary**: The following questions were submitted to EPA prior to an 8/28/14 conference call between EPA and Michigan Department of Environmental Quality about the proposed carbon power plan for existing power plants.

Additional comments from Michigan submitted on August 21, 2014.

**QUESTIONS FOR EPA ON 111(D) PROPOSAL**

1. It does not appear EPA’s calculation of coal plant efficiency savings includes the degradation of efficiency at coal plants when they are cycled up and down to accommodate greater use of natural gas combined cycle generation. If not why not? The degradation is a fact that is cited in EPA’s own Technical Support Document “GHG Abatement Measures” pages 2-5. There EPA states:

“Operating an EGU as a baseload unit is more efficient than operating an EGU as a load following unit to respond to fluctuations in customer electricity demand.”

1. Please provide the exact calculation, including all corresponding data and assumptions, of the 2012 MI carbon Intensity ratio.  It is important to understand how it is adjusted and  how nuclear affects the target.
2. Michigan’s assigned natural gas rate of 810 lbs/MWh is not consistent with proposed 111(b) requirements for new plants which are typically more efficient than existing plants. Please explain the basis for the assigned rate EPA used in the proposed rule.
3. EPA’s calculation includes 6% “at risk” nuclear which lowers Michigan’s goal to 1,161 lbs/MWh instead of a goal of 1,183 lbs/MWh if there was 0% “at risk”  nuclear. Why does existing nuclear lower the target? This presents a penalty to states that have invested in zero carbon generation and a disincentive for any utility contemplating upratings at existing nuclear plants.
4. How would electrical generation from hydro, biomass, and land-fill gas count toward meeting the goal?
5. Would Ludington Pumped Storage count as hydro? How should its generation be treated in reaching Michigan’s goal? Was the load represented by Ludington PS reflected in our state generation totals?
6. How can we accommodate unanticipated load growth in a mass-based system?  Would mid-term corrections be permissible?
7. Would EM&V have to be harmonized with other trading states if Michigan decides to take a multi-state approach to meet 111(d)?
8. How do we determine/control dispatch of any fossil-fueled EGU when this is performed by the RTO (MISO) under an economic market-based system of dispatch?
9. How do we calculate retirements of EGUs during the compliance period for federal enforceability under 111(d)?
10. How will EPA guarantee that heat rate improvements will not be considered subject to NSR permitting considering that the EPA and DOJ made the opposite argument in United States v. DTE Energy Co., 711 F.3d 643, 644 (6th Cir. 2013) even though actual emissions did not increase?
11. Is it accurate to describe that RE prior to 2014 will not be counted towards our CO2 reduction goal?
12. What is more important to EPA – the percent reductions Michigan obtains from a 2012 baseline or the intensity targets?
13. How will EPA allow states flexibility accounting for units that are prevented from retirement due to reliability requirements?
14. Because the proposed rule relies heavily on natural gas generation to replace coal generation, will the EPA allow relief from its GHG limits if the price of natural gas increases significantly beyond assumptions used in EPA’s modeling?
15. With its firm and significantly reduced limits on future GHG emissions, does the proposed rule establish a *de facto* cap on population and industrial growth in many states?
16. Because the rule may cause some states to mandate closure of some coal-fired power plants, has the EPA evaluated whether the rule is likely to jeopardize the future of public power in the United States given that public entities are generally not as well positioned to replace that generation as investor-owned utilities?
17. What is the EPA’s rationale for rejecting hydroelectric generation from every state’s renewable energy portfolio, while at the same time crediting all other renewable energy in states that have much higher renewable energy capacity factors than other states? For example, Kansas has a great deal more potential for generating energy from wind than Virginia, but Virginia has a greater potential for hydroelectric generation than Kansas. Why is Kansas allowed to use all of its wind generation to satisfy the EPA’s GHG limit, but Virginia is not allowed to use any of its hydroelectric generation?
18. Can EPA provide a sample conversion of a rate-based to a mass-based goal that relies on a portfolio approach?
19. Do energy efficiency measures require extensive monitoring or verification if the state employs a mass-based goal?
20. How can a state utilizing a mass goal successfully incorporate energy efficiency measures into their programs?
21. Will states have the option to count efficiency investments on the utility side of the meter towards meeting carbon limits?  They are as effective as customer improvements. Utility side of the meter improvements could provide additional advantages. Improvements to utility distribution could provide both carbon reduction and reliability improvements.
22. For the state plan, do final legislation, final rules, and other enforceable measures have to be in place or can they be proposed or draft requirements?
23. Please provide your rational for how heat rate improvements are going to be useful as part of the goal calculation in light of how to measure the improvements?  Utility comments to us have indicated that current methods used to estimate and report fuel heat input to EPA are not sufficiently precise to consistently detect a heat rate improvement of 6% or less.  We are also hearing that the 6% heat rate improvement is too high and expected heat rate improvements on coal-fired units are more in the neighborhood of 2 – 3%.  So potentially any heat rate improvements may not be measureable, and therefore, not helpful in achieving Michigan’s goal.
24. How will measures purchased in conjunction with federal incentives (new furnaces, for example) or new appliance standards count?
25. How will MISO, which dispatches on a regional (not state-by-state) basis, be able to economically dispatch NGCC units over coal to the extent that Michigan maximizes the savings from building block II?
26. What happens 8 years out when a new source is no longer considered new? (see p. 34,908 end of third column of FR version.)
27. How could a rate-based approach work in a regional cap-and-trade program?
28. What if a state meets the final goal, but does not continue meeting it at some point past 2030?
29. Would EPA have the authority to administer EE programs if Michigan failed to achieve its 2030 goal?
30. What happens if a state does not meet the interim goal but does meet the final goal?
31. What are acceptable guidelines for forecasting electricity demand growth over the compliance period (2020 – 2029)?  How will new plants be accounted for?
32. Under a mass based approach, if a coal plant is retired, are the total pounds of CO2 adjusted downward?  If a new plant replaces it, do the new CO2 emissions count?  If so, wouldn’t this encroach on 111(b)?
33. Under a rate-based approach, if a coal plant is retired, are the numerator and denominator adjusted downward?  If a new, more efficient plant replaces it, are the numerator and denominator adjusted upward?  If so, wouldn’t this encroach on 111(b)?