USEPA DOCKET COMMENTS
ID No. EPA-HQ-OAR-2013-0602
December 1, 2014

Comments on the federal Clean Power Plan proposal, EPA-HQ-OAR-2013-0602, by the Michigan Public Service Commission, the Michigan Economic Development Corporation, and the Michigan Department of Environmental Quality are contained herein:

EMISSION REDUCTION GOALS

The following are general comments on the state goals and the approach taken to determine them. These comments are more fully elucidated in the specific comments following this discussion.

Final Goals

In the calculation of the state goals there are three different goal numbers developed for Michigan in terms of percent reduction in the proposal and technical support documents (TSD): 31.5 percent, based on the adjusted rate in the preamble, 36 percent based on the numbers in the Goal Computation TSD, and 45 percent calculated from the initial to the final number in the Regulatory Impact Analysis (RIA) modeling. The following comments are based on the proposal preamble, (the 31.5%) and not the differing supporting documentation.

The differing goal numbers illuminate inconsistencies between the TSD and RIA (which typically align in the rulemaking process) and make it difficult to understand and comment on the goal's development. Further, the documents are not reflective of the proposal; therefore, Michigan must question the thoroughness, consideration, and analytical depth applied to this proposal given the lack of accurate supporting documentation. Michigan is proceeding under the assumptions presented in the proposal preamble; however, we believe the United States Environmental Protection Agency (USEPA) should align these documents and give additional time to adequately review and comment on the proposal. Stated another way, these comments are valid and appropriate based only on this assumption. If this assumption is incorrect, the USEPA must realign these documents and repropose the rule.

Currently, the goals are set in a way that creates inconsistencies between states. This offers neighboring states a competitive advantage over Michigan. Given that Michigan was an early adopter of a renewable portfolio standard (RPS) and energy efficiency (EE) programs[1] and other states were not, Michigan is tasked under the proposal with a greater level of renewable energy (RE) and EE goals. This is an inequitable burden that must be equalized in the final rule. Those impacts are contrary to the requirement that USEPA "must not give competitive advantage to one state over another in attracting industry" when setting new source performance standards.[2]

In addition, Michigan began implementing its RPS/EE programs in 2009, well before the 2012 baseline used in the proposal, and associated carbon reductions will continue into 2015 and beyond. At this time there is consideration of extending or expanding the RPS/EE programs with new legislation; however, the uncertainty around the state's ability to obtain credit for such early action is a disincentive to expand the programs, and may even serve as an incentive to suspend these programs until 2020. There is additional discussion on these issues in subsequent portions of this document.

Furthermore, the schedule laid out in the proposal may not provide enough time to fully develop a state plan. States must decide by June 2016 whether to participate in a multi-state plan; however, it seems highly improbable that two or more states will be prepared to commit to a multi-state plan in such a short time frame given the long lead times needed for reaching consensus on commitments of this level. The evaluation of the rule itself and determination of individual state impacts will take a significant amount of time during the first year. Following that, modeling and negotiations will be necessary to determine the merits and feasibility of a multi-state plan. If a multi-state plan is ultimately decided on, it would almost certainly require state legislative action that, at a minimum, would add one or more years to the process. In the instance where one of the states has a biennial legislative schedule, this would likely take a minimum of three years.

Even if a state decides to develop an individual state plan, the schedule is challenging. Depending on the commitments the USEPA will require in the state plan, it may be necessary to develop enabling state legislation. Given the June 2015 to June 2017 time frame (with an assumed one-year extension), it is very unlikely that submittal of a complete state plan is possible. Much like the federal process, in Michigan, a USEPA rule must first be evaluated, input from a stakeholder process gathered, and a public comment process met. This shortens the available time frame by six months or more. A flow chart depicting the internal rule approval process for Michigan air rules is included as Attachment 1. This process takes a minimum of 18 months and is based on the assumption that the Michigan Department of Environmental Quality (MDEQ) has enabling legislation to develop the appropriate rule(s). In short, the USEPA must reconsider the time line for the development of state plans. One year is inadequate for most states, so Michigan supports the allowance of an additional year. In the case of a multi-state plan where there is collaboration between states and state legislating action will almost certainly be necessary, three years (or by 2018) is not an achievable time frame.

The proposed alternative compliance time frame is impractical with front-loading of the reductions and final achievement by 2025. This alternative would only allow a five-year window (between 2020 and 2024) to meet the final goal. Although the alternative does come with reduced overall and interim goals, the proposed time frame is impractical (discussed later) and would likely result in greatly increased costs to the ratepayers; therefore, Michigan does not support the alternative goal approach.

Interim Goals

An interim goal of 70 percent of the proposed 31.5 percent overall emission reductions by 2020 is unattainable. Instead, there should be a glide path with reasonable further progress reports describing advancement toward meeting the final goal. It is reasonable to expect the reports be required by 2020. As previously discussed, there are procedural requirements that must be met to achieve the final goal. Requiring the majority of reductions by 2020, especially given the lack of credit for early leadership, presents significant challenges and does not allow the state flexibility in determining the best path forward and pace for achievement of the final goal. There are significant infrastructure needs associated with this proposed rule and other environmental regulations, and there is simply inadequate time to provide an orderly transition of Michigan's generation fleet to meet the interim goal. That is, the interim goals could threaten the reliability of Michigan's (and the region's) electric system (Analysis of EPA's Proposal to Reduce CO2 Emissions from Existing Electric Generating Units, Midcontinent Independent System Operator, November 2014 [Appendix A]) and cause rate shock.[3] Michigan proposes that the pace and path be left to the state to decide, so long as it attains the final goal set forth in the rule.

BEST SYSTEM OF EMISSION REDUCTION (BSER)

The underlying assumption that the proposed final goal can be met by adjusting the BSER baseline building blocks is fundamentally flawed. The assumptions made in the first two building blocks are not technically viable for Michigan or most other states; therefore, the methodology in the goal calculation must be reconsidered. Further explanation and comment is provided in the detailed discussion of the building blocks below.

State-Specific Data

Michigan does not agree with the USEPA's use of a single year's data (2012) as the basis for the application of the building blocks. In no case is one single year representative of energy demand and dispatch for a variety of reasons, including weather, economic conditions, and plant outages, to name only a few. Application of the building blocks should be based on at least a three-year average baseline, 2010 through 2012. Michigan's three-year average calculated for years 2010 through 2012 is included as Attachment 2. In addition, Michigan's 41 municipal utilities, as well as the vast majority of Michigan's 10 electric cooperatives, are not rate-regulated by the Michigan Public Service Commission (Commission). Commission authority is limited to certain statutory requirements such as compliance[1] with the state's ten percent RPS by 2015 and the state's EE target of a one percent reduction in annual retail electricity sales. It is important to note, however, that these utilities typically lack the size and/or capability of larger investor-owned utilities (IOU) in both their energy requirements and magnitude of energy generation. Hence, additional burdens to meet aggressive carbon dioxide (CO_2) reduction targets may place these smaller utilities at an economic disadvantage that in some cases would raise the question of continued reliability in already constrained areas of the state.

As discussed in the proposal, the USEPA should allow intrastate and interstate trading programs and emissions averaging to be used for goal compliance in the final rule. Including these options would give states more opportunities to lower the cost of compliance and would provide the greatest flexibility and economic leverage for states, while still allowing them to meet the required CO_2 reductions. Although it is unclear if Michigan would benefit from a multi-state trading program, the option should be provided for in the final rule.

Additional Measures

The USEPA is requesting comment on the consideration of additional measures that can be used to attain compliance. The USEPA should count the CO_2 emission reductions that result from the implementation of a variety of measures, including those not currently included in the proposed BSER. Such measures include, but are not limited to: incremental hydroelectric generation, incremental nuclear generation from unit up-ratings, biomass, coal plant retirements, heat rate improvements at fossil plants other than coal-fired plants, conversion of simple cycle combustion turbine units to combined cycle, transmission and distribution system efficiencies, retrofitting of existing electric generating units (EGU) with carbon capture and sequestration (CCS) technology, co-firing of lower-carbon fuels at fossil plants, landfill gas electric generation, waste-to-energy plants, and combined heat and power (CHP). These additional measures should be credited with a full generation replacement. That is, one megawatt (MW) generated by one of these measures should receive full credit as one MW of RE. All of these measures result in lower CO_2 emissions and, therefore, meet the intent and objective of the proposed rule.

Gas conversion or co-firing also termed “fuel switching” (from coal to natural gas) should also be considered as part of the BSER. There are obvious co-benefits with gas conversion resulting in the reduction of both Criteria and hazardous air pollutants. It should be noted, however, that gas conversion of a coal-fired boiler will not result in a 40 percent CO_2 reduction as would replacement with a new natural gas combined cycle (NGCC) unit. Conversion of an existing boiler designed to burn coal will be inherently less efficient due to combustion zone and heat transfer design.

Economic Conclusions

While the exact economic consequences of implementing the proposed rule under Section 111(d) are uncertain at this time, there is no doubt the utilities’ cost to comply with the various CO_2 reduction measures will be passed along to ratepayers. The existing USEPA Mercury and Air Toxics (MATS) rule looms as a financial hurdle for utilities, as decisions are made to either retrofit or shutter coal plants across the state and nation. Beyond the capital costs required to keep coal plants operational past the

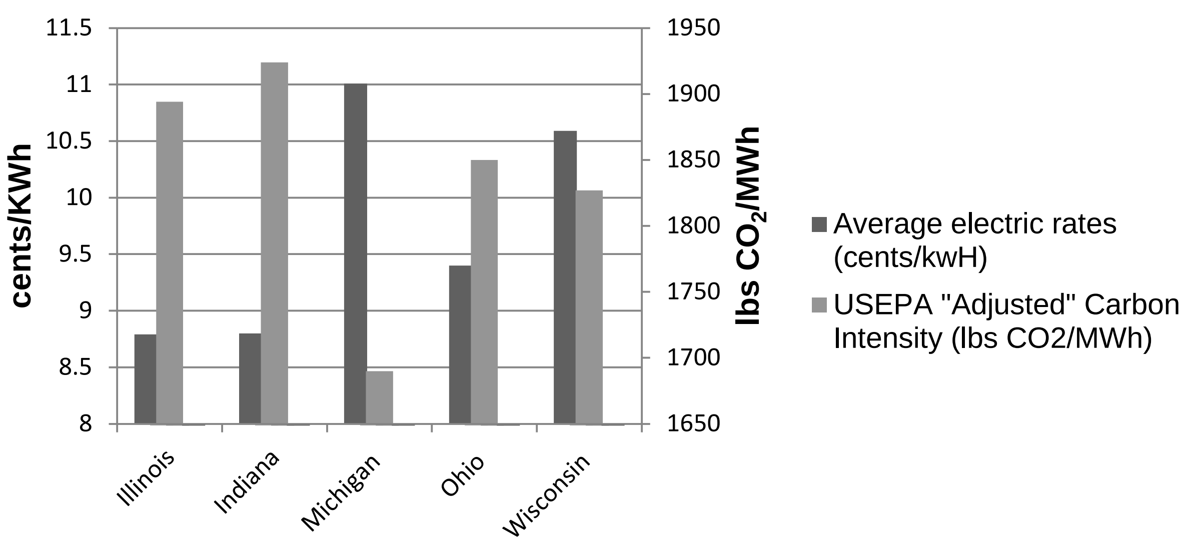
MATS rule compliance date, utilities may seek to recover plant investments. Thus, customers may face substantially higher rates as utilities seek to recover new environmental capital expenditures, new generation, and retrofits, as well as infrastructure investments such as electric transmission and natural gas pipelines.

The economic impact has both an absolute and a relative dimension. This rule as drafted is especially punishing in the relative dimension. Simply put, unless the rule is rewritten to reward smart investments, Michigan faces a large and artificial competitive disadvantage.

The Energy Information Administration (EIA) regularly publishes average electric rates by region, in which Michigan is categorized in the "East North Central" region and compared to the rates of Illinois, Indiana, Ohio, and Wisconsin. Michigan's relative electric rates compared to these states and other regions are a challenge to its economic recovery.

Michigan's CO_2 intensity is significantly lower than that of other East North Central states, while electric rates are higher (Figure 1). Though Michigan's measures implemented to lower carbon intensity are not the *only* reason its rates are higher than those of surrounding states, its willingness to pay for diversifying its power generation, even in the midst of the recent devastating economic crisis, contributes to this difference. Those choices, while difficult, were readying Michigan, in part, for possible economic and regulatory changes. Instead, because of the way the proposed rule is drafted, the USEPA could turn Michigan's wise early investments into a disadvantage.

Figure 1[4]



Michigan's USEPA "adjusted" carbon intensity is currently nine percent below the average for the other states in the East North Central Region and 12 percent below the highest intensity states in that same region. Using the rule's proposed requirements[5], in

2030 Michigan's carbon intensity goal will be 13 percent below the average for the other states in the region and 24 percent below the state with the highest permitted intensity. In other words, unless compliance with the rule is costless (a situation the USEPA does not appear to allege), then the USEPA's rule will severely impact Michigan's relative competitiveness; in some cases at least doubling the disadvantage Michigan now has regarding electric rates.

This disadvantage is likely to be even greater, as the most likely scenario is that incremental improvement will actually be more expensive for states like Michigan that have already implemented the more cost-effective measures. In other words, the additional reduction being required is likely to be higher in cost per unit of reduction for states that have already shown leadership in diversifying electric generation and reducing energy waste. These different starting lines would make even an equal compliance goal more expensive for Michigan than for other states.

Under the rule's current structure; however, it is not just the starting line that punishes leaders, the finish line is also farther away for Michigan than any other state in the region. Under the proposed rule, the most carbon-intensive state in the region will have to reduce its carbon intensity by approximately 400 pounds (lbs) per megawatt hour (MWh), while Michigan will be required to lower its intensity by approximately 500 lbs/MWh. This both penalizes diversity in electric generation and is arbitrary and capricious. Where the goal is the reduction of a pollutant, it makes little sense to require a state to deeply worsen its economic position relative to its neighbors because it pollutes <u>less</u>, especially when other states are not required to reduce their intensity to the same absolute level.

<u>**BUILDING BLOCKS**</u>

<u>Building Block 1</u>

Building Block 1, as proposed, does not properly represent BSER. In the Greenhouse Gas (GHG) Abatement Measures TSD, the USEPA assumed that all coal-fired power plants could increase their heat rate efficiency by six percent based on a statistical analysis of heat rate contained within the 2009 Sargent and Lundy (S&L) report titled <u>Coal-fired Power Plant Heat Rate Reductions, 2009</u>.

The USEPA applied "best practices" for improvements and "further equipment upgrades." The statistical approach taken for "improvements" is somewhat puzzling given that the USEPA reduced variability in heat rates "because the deviations generally result in performance worse than optimal heat rates." Statistically, variability is a change relative to an average value, but in this case, the USEPA made it relative to an "optimal" (minimal) value, thereby, skewing the results to a higher percentage value reduction.

Using the S&L report for establishment of “upgrades” to equipment, the USEPA assigned the highest value to equipment upgrades and created four measures for improvement. By assuming that all EGUs would benefit from a worst case equipment upgrade, the USEPA erred, given that even the S&L report stated these might apply in some cases. It should be noted that the requirements to meet the MATS rule creates a daunting hurdle for utilities to meet even a two or three percent heat rate efficiency improvement. The USEPA extrapolated the S&L report results to all coal-fired EGUs, many of which have already made efficiency gains. Two other reports cited in the GHG Abatement Measures TSD, a 2009 United States Department of Energy (DOE) National Energy Technology Laboratory report and a 2013 Congressional Research Service report estimate the available heat rate efficiency nationwide at 2.5 percent.

Also, three of the four “upgrade” measures (noted below) have been cited in numerous New Source Review (NSR) violation court filings by the USEPA and the United States Department of Justice.

1. Economizer replacement.
2. Combined variable frequency drive and fan replacement.
3. Turbine overhaul (apparently rotor replacement).

The USEPA has not addressed how these measures would be treated under the rule with respect to NSR, and how such a review would potentially make them subject to a 111(b) modification. This begs the question, given Section 111 clearly separates modified sources from existing sources in the definitions and potentially serves as a disincentive to upgrades, how will such upgrades be dealt with in respect to NSR under this Section 111(d) rule?

Efficiency gains, unlike emission reductions, cannot be continually ratcheted down beyond a certain point. As Einstein said, “Energy can neither be created nor destroyed…” The USEPA proposal in Building Block 1 relies on the assumption that energy will be created by regulation, which may be a noteworthy and unique goal, but that does not make it physically possible. The goal for Building Block 1 should be reduced to a more realistic and attainable level.

In addition, any fossil-fuel EGUs (coal-fired) that are planning to retire as a result of USEPA regulations (MATS, etc.) should be allowed to count towards compliance with the goals. Michigan’s largest utilities have already announced some closures of coal-fired EGUs and more are expected to be announced in the next couple years, resulting in substantial reductions in CO_2 emissions from these to-be-retired coal plants.

Building Block 2

The USEPA assumed a 70 percent utilization rate of all NGCC in the state without regard to how these units are dispatched by the utilities and Regional Transmission Organizations (RTO). While Michigan agrees greater dispatch of NGCC plants is environmentally desirable, the USEPA has not identified any tools to do this and has not addressed federal regulatory barriers. In Michigan, the majority of the NGCC capacity is dispatched by the RTO, Midcontinent Independent System Operator (MISO). Generation dispatch and the transmission grid are managed by MISO based on security constrained dispatch and locational marginal pricing to set the market price of electricity. The state has no authority over this dispatch process and no mechanism to force or modify dispatch of these plants.

In Michigan, one NGCC plant with a rated nameplate capacity of 1,100 MWs is owned and operated by an Independent Power Producer (IPP). The plant's units will soon be dispatched by a different RTO, PJM Interconnection (PJM) via a proposed direct transmission line that leads out of the state. In this case, even a Michigan CO_2 price forcing dispatch within MISO for electricity sold in Michigan would have no effect on this plant's generation since it is being bid, sold, and supplied into another RTO.

The USEPA states that Building Block 2 is achievable because states can "encourage" redispatch through an allowance-based system like the Regional Greenhouse Gas Initiative (RGGI) (*79 Federal Register* at 34882). It should be noted that while RGGI is currently operating in three RTOs, New England Independent System Operator (ISO), New York ISO, and PJM, setting up a similar system in other parts of the country could be very complex and time consuming. Starting up a new system similar to RGGI would likely require several years of development, adding to the amount of time that would be required to implement state plans.

The alternative scenario for which the USEPA seeks comment assumes a NGCC dispatch of 65 percent. The same issues remain for dispatch at 65 percent that were previously discussed.

With reference to the USEPA's Integrated Planning Model modeling, the assumed price forecast for natural gas may not be sustainable in the future due to increased demand placed on this fuel for both heating and electric generation, as well as offshore sales of liquefied natural gas (LNG). While cost impacts for this building block are unknown at this time, increased demand is likely to increase the cost of domestic natural gas that in turn may increase electric rates.

The discussion of modeling results in the proposal refers to a region's existing fleet, and such a reference is only meaningful if there is regional trading. While this may be an alternative, it should not be assumed for purposes of determining potential economic impact. The USEPA cannot assume that the economic impact will be based on a regional trading program since that option has not yet been determined to be an economically viable option for any individual state; therefore, the USEPA must reconsider this assumption.

Based on actual (and historical) capacity factors (CF) of Michigan's NGCC fleet (approximately 5,000 MW of capacity) (Attachment 3), the USEPA's proposed redispatch of NGCC units to a 70 percent CF appears both unrealistic and unachievable. Even with historically low natural gas prices for NGCC EGUs, Michigan only achieved an approximate average CF of 42 percent for its NGCC units in 2012. This is due in part to the existing RTO merit order dispatch construct, where lower cost units are dispatched before higher cost units. Even if one were to assume a continuation of low cost natural gas fuel for NGCCs, these units are typically not called upon to run as baseload plants in meeting electric supply and demand. Doing so would require more frequent and costly maintenance causing extended outages, both forced and unforced.

Another important consideration in the proposed redispatch of NGCC is the difference in firm and non-firm natural gas supply contracts between generators and gas suppliers (Attachment 4). Firm natural gas supply for year-round service is expensive to obtain for generators in a competitive wholesale market. Typically, NGCC units are used during peak summer periods when the supply need is greatest and non-firm gas supplies are utilized; however, if NGCC units are expected to operate at a higher CF, they would require a secured firm gas supply or face supply constraints and/or price spikes forcing limited run time. In addition, price volatility of natural gas is a key determinant with respect to higher utilization rates for NGCC units, as the fuel cost typically sets the marginal price and associated offers of these units in the market.

Furthermore, as seen during the 2014 “Polar Vortex,” our nation’s natural gas supply and existing infrastructure to transport gas to electric markets was strained to the breaking point. Assuming additional output as a result of a 70 percent CF from these units during another event of this magnitude would most certainly put large swaths of the United States at risk of unmet electricity demand, potentially creating brownouts or blackouts. A more appropriate target would be in the low 40 percent range for CF of NGCC units.

The USEPA calculated a heat rate of 810 lbs CO_2/MWh for NGCC plants in Michigan, while the proposed heat rate for new NGCC plants is 1,000 lbs CO_2/MWh. What should be noted is that the 810 lbs CO_2/MWh is based on only one year (2012). The heat rate for these plants is dynamic, not static. The average heat rate for NGCC plants in Michigan based on the years 2010 through 2012 is 986 lbs CO_2/MWh, which is more representative than the numbers used by the USEPA.

The USEPA does not credit CHP properly in the proposal. In Building Block 2, by dividing the CO_2 emissions by the gigawatt hours generated, there is no accommodation for the use of waste heat by CHP. This leads to an incorrect lowering of the ratio used in the calculation. There should be an adjustment either by the addition of CO_2 in the numerator or a reduction in the denominator to credit CHP. The use of CHP directly offsets CO_2 from otherwise operating combustion sources and should be credited in this rule.

Building Block 3

The USEPA developed the RE goals by regions without regard to potential RE opportunities or electric grid interconnections between states with higher RE potential and states with lesser RE potential. "The front-loading" of RE prior to 2020 presents timing challenges that may be insurmountable.

A better approach would be to allow a "glide path" determined by the state with reports to the USEPA on progress beginning in 2020. This approach would allow states more flexibility and control of development costs to minimize ratepayer impact, while still attaining the final goal.

Michigan also supports the alternative proposal for Building Block 3 with caveats. It is more reasonable and realistic for Michigan to base its state plan on the technical and economic potential available for RE in our state. Michigan has already done extensive work regarding the availability and practicality of expanding RE in our state (Appendix B). This alternative; however, should not set a larger target for RE and additional hydropower should be included.

Combining a technical and economic approach, including the preceding caveats, to developing an RE plan is the most reasonable approach. This provides Michigan the opportunity to use well developed information through an extensive stakeholder process.

By law, Michigan's utilities must obtain ten percent of their energy needs from RE sources by 2015. Michigan recommends that hydropower count towards the CO_2 reduction target. Currently, approximately three percent of our state RE comes from hydropower (run-of-river) and provides carbon-free power to a variety of utilities.[6]

Current state law allows utilities to buy Renewable Energy Credits (REC) to meet the state RPS target. Approximately three percent of Michigan's compliance RECs come from RE generators located outside of the state. These generators may be owned by a multi-state utility that serves Michigan or purchased by a Michigan electric provider under a power purchase agreement. It is unclear whether the USEPA would count this renewable generation toward Michigan's Building Block 3. The USEPA should allow for credit of purchased RECs towards achievement of the state's CO_2 reduction target.

In addition, Michigan has significant biomass resources, including woody biomass, anaerobic digester potential, waste wood products from furniture and paper manufacturing, and municipal solid waste. Michigan recommends that biomass be considered carbon neutral and that Michigan's definition of biomass meets the requirements of Building Block 3. "Biomass" is defined in state law to be:

> "… any organic matter that is not derived from fossil fuels, that can be converted to usable fuel for the production of energy, and that replenishes over a human, not a geological, time frame, including, but not limited to, all of the following:
> (i) Agricultural crops and crop wastes.
> (ii) Short-rotation energy crops.
> (iii) Herbaceous plants.
> (iv) Trees and wood, but only if derived from sustainably managed forests or procurement systems, as defined in Section 261c of the management and budget act, 1984 PA 431, MCL 18.1261c.
> (v) Paper and pulp products.
> (vi) Pre-commercial wood thinning waste, brush, or yard waste.
> (vii) Wood wastes and residues from the processing of wood products or paper.
> (viii) Animal wastes.
> (ix) Wastewater sludge or sewage.
> (x) Aquatic plants.
> (xi) Food production and processing waste.
> (xii) Organic by-products from the production of biofuels."

The final rule should clarify what types of biomass can count toward Building Block 3. In cases where a generator uses multiple fuels, such as a woody biomass plant that burns both woody biomass and tire-derived fuel (which is not considered renewable in Michigan), the generation reported would include all of the MWh generated, but RECs would only be awarded for the renewable portion of the generation. However biomass is treated in the rule, the USEPA should treat it the same in both the goal setting and the compliance demonstration.

Michigan does not agree that biomass be included in the numerator as "other generation" since this is a carbon neutral source of energy. The treatment of biomass in the final rule should only appear in the denominator as new biomass energy production comes on line and counted as a renewable resource.

Michigan may experience rapid growth in the number of small solar projects where the generation is used by the customer behind the meter. The rule should include a methodology for counting behind-the-meter distributed generation if metering and monthly reporting requirements are onerous. Michigan's REC tracking and certification system, MIRECS, provides for aggregation of similar generators into a single account to reduce administrative costs. Annual generation is calculated using a formula. In addition, MIRECS includes both monthly generation and RE credits awarded.

Michigan favors the inclusion of incremental hydropower, including new construction and uprates, in the RE calculation. The year-to-year variation in hydropower generation could be accommodated by using a three-year average. Currently, Michigan has approximately three percent hydropower that counts towards its RPS.

Michigan's RPS provides for RECs that are valid for three years. The rule should clarify that banked generation from previous years will be counted toward a current year in Building Block 3. Michigan strongly supports the use of RECs from 2012 to 2030 for goal compliance purposes. These RECs represent a sizable economic investment and have displaced carbon emitting generation. If the goal truly is to reduce carbon, these gains should not be ignored. The same can be said for energy waste reductions accomplished during the years 2012 through 2030 and continuing to provide air quality benefits in those years.

Nuclear

Michigan currently has four operating nuclear reactors at three plants. Three nuclear reactors (D.C. Cook 1 and 2, and Palisades) were recently relicensed by the Nuclear Regulatory Commission (NRC) to operate another 20 years, and one (Fermi II) is currently under review by the NRC for relicensing. As such, while Michigan qualifies to claim the 5.8 percent "at risk" provision under Building Block 3, it is unclear as to whether the USEPA's proposal provides any incentive worth claiming for the carbon reductions attained through the use of nuclear generation, even though nuclear generation does not emit any of the pollutant actually being regulated, while natural gas generation does.

While we generally understand the approach proposed by the USEPA to keep existing nuclear assets that are at risk of premature shut-downs to continue operating, we fail to see how this treatment protects the ability of those existing nuclear assets to continue producing base-load, zero-carbon energy. We recommend USEPA consider adopting another methodology as a means to incentivize continued operation of existing nuclear assets. Possible methodologies include;

> Consider all or a substantial percentage of generation from existing nuclear units and assume a more reasonable capacity factor reflecting forced/unforced outages in setting the standard. This would create a tangible incentive for states with nuclear to use for compliance purposes.
>
> Remove nuclear generation from the existing rate-setting formula, but allow states to reflect any retired nuclear units by removing lost generation from prematurely closed nuclear units from the denominator of the compliance rate formula.

In the above context, we recommend the USEPA consider a "safety valve" approach in the state compliance plan to address compliance risks in certain situations such as:

> Retirement of a nuclear unit prior to its licensed life.
>
> Equipment failure or catastrophic event that renders the unit uneconomic to repair or replace.

> Nuclear uprating projects and relicensing should be able to be credited towards compliance as well. The additional generation would be added into the denominator of the goals.

Michigan recommends that the 5.8 percent nuclear generation component should be removed from states' interim and final goals. The current methodology of adding 5.8 percent of the state's 2012 nuclear capacity (operating at a 90 percent CF) into the rate-based goal denominator has the effect of needlessly lowering a state's final and interim goals. The fact that most states with nuclear generation would receive this MWh "credit" with virtually no change to the state's electric industry does not justify the inclusion of this element to the BSER. It does not reflect the full extent of a state's nuclear generation.

"Forced and unforced" outages were experienced at all four of the nuclear plants in Michigan during 2011, 2012, and 2013. Nuclear units require periodic planned outages (unforced) for refueling the reactors, as well as performing routine maintenance while the units are down for refueling. Beyond these planned outages, the nuclear units in Michigan also had "unplanned" or forced outages due, in part, to equipment failure, water leaks, and safety-related issues, which resulted in the units being down for considerable amounts of time. As nuclear units typically operate 24 hours a day, seven days a week, 365 days per year due to their inherent design and operation, having units down for more than the unforced outages required utilities to obtain replacement energy from the MISO market to meet their customer demand during this period. This replacement energy was comprised of a mix of generation fuel types, most of which was coal and gas. Hence, the emission profile for 2012 reflects a variance from what the emission profile would have been had the nuclear units been operational under their typical CFs. Attachment 5 contains the EIA spreadsheet of data on Michigan's nuclear units for the years 2011 through 2013.

The CF of Michigan's nuclear fleet in 2012 was 80.6 percent, which is less than the 90 percent CF assumed in the proposed rule. Outages in April and December at Fermi II were largely responsible for lowering this fleet wide CF. Plant outages may be unavoidable and the USEPA's proposed treatment of nuclear generation gives little accommodation to this operational reality. The current methodology assuming a 90 percent CF creates a larger carbon reduction obligation than if the USEPA had used 2012 nuclear generation (in MWh and also multiplied by 5.8 percent). A three-year average (2011 to 2013) of the fleet wide CF would yield 86.4 percent, still less than the 90 percent CF assumed in the USEPA's calculation.

It is important to note, however, that due to increased natural gas generation and renewables across the United States, as well as RTO market structure issues, nuclear generation is facing economic pressures to compete on a more level playing field and remain viable into the future as part of our base-load energy mix. Indeed, this issue bears individual attention by federal regulators (Federal Energy Regulatory Commission [FERC] and NRC) beyond the application of an "at-risk incentive" within the confines of USEPA Section 111(d) compliance.

Building Block 4

Michigan interprets the rule, as proposed, as not allowing emission reductions from EE measures installed prior to 2017 as one of the options proposed to count toward achievement of the interim and final goals. Michigan does not agree with this proposed cutoff date and recommends adopting the USEPA's proposed option of recognizing emission reductions that existing state requirements, programs, and measures have achieved starting from the end of 2005. Michigan has had an EE standard in place since 2008 and urges the USEPA to allow the savings from measures installed before 2012 to be counted toward compliance with a state's plan. At a minimum, the USEPA should allow the electricity savings from all measures beginning January 1, 2012, to count toward the state's goal.

The proposed rule states:

> "Emission impacts of existing programs, requirements, and measures that occur during a plan performance period may be recognized in meeting or projecting CO_2 emission performance by affected EGUs according to § 60.5740(a)(3) and (4), as long as they meet the following requirements:
>
> (1) Actions taken pursuant to an existing state program, requirement, or measure, such as compliance with a regulatory obligation or initiation of an action related to a program or measure, must occur after June 18, 2014…"

The USEPA should also be aware that only counting emissions as one of the options proposed from 2020 through 2029 creates a perverse incentive for states and utilities to defer implementation of EE programs until 2017 or later, out of a rational concern that all of the emission reductions from measures installed between 2014 through 2017 would not count due to concerns about the "acceptable" lifetimes of various measures. In Michigan, if the Legislature amends the EE statute, there would be little reason to make such a statute effective until 2017 or later. This would result in more CO_2 being emitted into the atmosphere than might occur with a final federal rule that encouraged investment in EE to occur as soon as possible.

Michigan has conducted an extensive study of the potential for EE in the state titled, Michigan Electric and Natural Gas Energy Efficiency Potential Study Report, dated November 5, 2013 (Appendix C). In addition, Optimal Energy conducted an analysis on Michigan's behalf entitled Options for Establishing Energy Efficiency Targets in Michigan: 2016-2020, dated November 21, 2013 (Appendix D). The final rule should allow the state to make a demonstration that the state plan is based on the documented achievable technical and economic potential available in our state.

For Building Blocks 3 and 4, Michigan does not support either of the approaches for revising the state goal-setting formula that were presented in the Notice of Data Availability (NODA) in Sections III.C.1.a and b. The implementation of the goal-setting equation proposals in the NODA is not supported by actual operations but rather aspirational operations. First, proposing to replace all historical fossil generation on a pro rata basis assuming that replacing fossil steam and NGCC generation after 2012 may not be correct. The additional generation from RE or avoidance of generation by EE may have actually offset some new fossil generation and cannot be assumed to always offset other generation especially when comparing to a single year: 2012. Second, proposing the prioritization of replacement of historical fossil steam generation is not based on the reality of electrical dispatch. The alternative proposal presupposes that incremental and avoided generation would replace higher-emitting fossil steam generation first. In the MISO region, the electrical dispatch is by price. Therefore, the assumption of replacement of fossil steam generation used in this case is not valid.

<u>Carbon Capture and Sequestration</u>

The USEPA did not propose CCS as BSER for existing sources; however, Michigan is submitting cost information for the record on this technology. CCS at this time faces an economic barrier and is not practical to apply to most EGUs regulated by the rule. A projection of costs for CCS was completed as a “Phase I DOE Project” (Appendix E) when Wolverine Power Cooperative applied for and received a coal-fired EGU air permit in Michigan. The capital costs for transportation of the carbon dioxide 52 miles to an existing enhanced oil recovery (EOR) site were in the range of $130 million (M) to $170M with annual operating costs of $4M to $5M. The potential annual EOR revenue is $20M to $40M. While the potential revenue is adequate to cover the cost of transportation and oil recovery, it does not provide revenue adequate to cover the capital costs of carbon capture at the power plant, which is in the range of $210M. These costs are for CCS of only 15 percent of the CO_2 from a 300 MW unit and do not cover the cost of 100 percent CCS of the plant emissions.

Given that the DOE CCS research will not be complete until 2020, financing will not be available to build a coal-fired power plant without government subsidy for an unproven coal technology. The Administration's budget for funding of new CCS projects in the future is unlikely or uncertain at best. Additionally, retrofitting existing units is always more costly than new construction, and pipelines would have to be permitted and constructed, further adding to the cost, complexity, and time constraints of such approaches.

<u>TIMING OF COMPLIANCE</u>

If generation from a single year remains the baseline for calculating future goals, Michigan would recommend using the year 2005 for calculating CO_2 reductions going forward. By not giving credit for reductions made by a RPS, the USEPA has penalized the state in two ways. First, no credit is given for expenditures by the ratepayers to achieve these real emissions reductions. Second, by not crediting these reductions, but using them to establish a baseline, the USEPA has set the 2030 targets at a more stringent level for states that invested in early action, but less stringent for states that failed to do so in the same time frame.

Michigan does not agree that 2012 should be the year chosen for a basis of reduction of CO_2, rather we support a three year average (2010 through 2012). There is nothing in Section 111 of the Clean Air Act (CAA) that mandates a particular year. Indeed, Section 111(d) requires a "State Implementation Plan (SIP) like" process filed by the state. In the past year, the USEPA has considered different years for Section 110 SIPs.

The USEPA requested comment on state plans tracking emissions after 2030 and for corrective measures. Michigan suggests that the state plan include identification of corrective actions that can take place should the state not meet or maintain its goal after 2030. This is similar to the Section 110 SIP process wherein contingency measures are identified in the initial SIP submittal. A similar process should be available in the final Section 111(d) rule.

Michigan does not support establishing a deadline for the update of a state plan ten years in advance. There should be an opportunity to update corrective measures, but establishing a deadline a decade in advance presumes that there will be enough information to establish or confirm plans. A state submittal requesting comment on an anticipation to update a state plan by 2025 seems appropriate since this could inform the USEPA on the progress or anticipated challenges to the state plan.

Additionally, the impact of electrification of the transportation sector and solar technology in the future cannot be known at this point in time. The manufacture of polycrystalline silicon for photovoltaics requires huge amounts of electricity, and one such company is one of the state's biggest electricity consumers using approximately 400 MW. There should be a mechanism to adjust the goals if GHG measures such as vehicle electrification and solar panel production cause a shift in emissions from one sector to another.

If 2012 remains the year from which calculations for CO_2 reductions are made, the reduction calculation should be credited from 2005. If the USEPA does not use 2005 for the base year, then 2012 forward should be used rather than starting in 2020. There is no language in the CAA Section 111(d) to suggest an interim goal is appropriate or required. In prior Section 111(d) regulations, the USEPA did not propose interim scheduled reductions. The calculation for reductions should be no later than 2012.

ACHIEVEMENT AND MAINTENANCE OF FINAL PERFORMANCE LEVEL

Michigan agrees that a three-year average for demonstration of achievement and maintenance is an improved amount of time. Michigan does not agree with an established interim goal. Instead there should be a glide path with the states reporting progress to the USEPA. As stated earlier, there is no statutory basis for requiring an interim goal.

Michigan also agrees with the proposal of a final actual plan performance check using a three-year rolling average, the first year of such a check being 2016. By allowing credit for EE in 2012 and beyond, the state could make a show of progress for RE and EE with the state plan submittal.

REDISPATCH

The USEPA asked for comment on re-dispatch between sources in two categories: coal-fired EGUs and NGCC units as a component of BSER. As previously discussed, the state does not call on facilities for dispatch of electricity. The dispatch or re-dispatch is managed by the RTOs, and is a complex system that crosses state lines. The RTOs are regulated by FERC and follow federal rules governing dispatch based on prices bid by operators of electric generators.

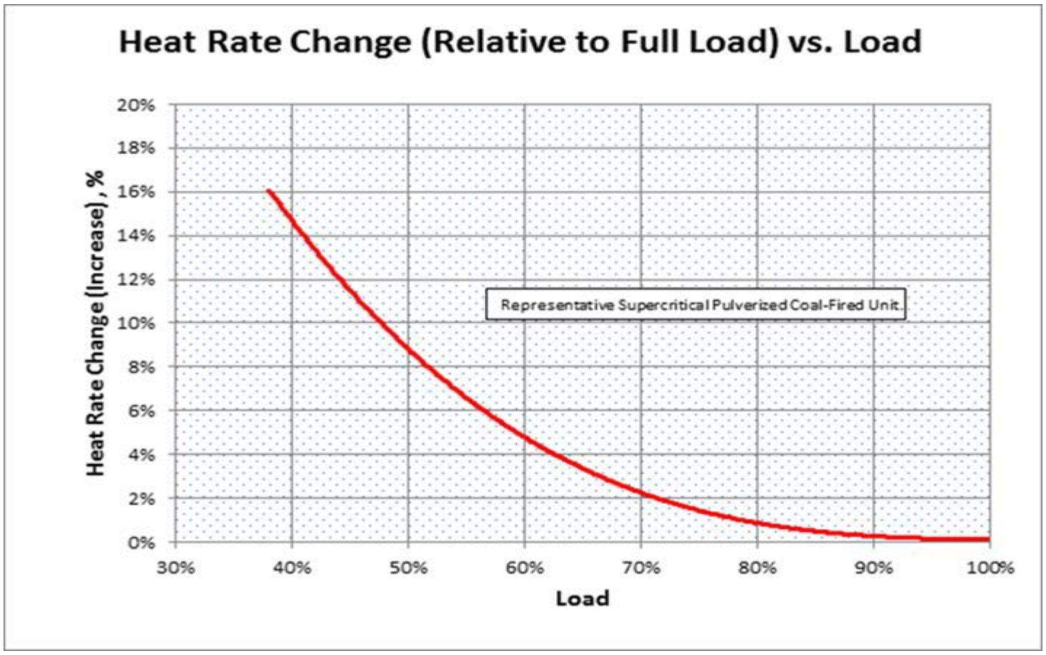
The New Covert plant located in Southwest Michigan is one of the largest NGCC plants in Michigan and serves as an example of complications with the USEPA's assumptions that dispatch is directed by states and should be placed in state plans. This plant is an IPP and is not regulated by the Commission. The state cannot legally require the facility to operate at a 70 percent CF and has no ability to influence the market in any way that would drive the dispatch of this plant other than participating in a carbon tax system that is added to bids. Even this has been brought into question due to a recent court decision (Appendix F)[7] in which the state of New Jersey approved contracts for new generation that paid the difference between what the generator would make in the wholesale market through PJM and the bid price, thereby providing a predictable and adequate stream of revenues to ensure generation is built in the state in order to address reliability and other concerns, Courts overturned state decision. The Third District Court of Appeals concluded:

> "We affirm the District Court's judgment. Long-term Capacity Pilot Project (LCAPP) compels participants in a federally-regulated marketplace to transact capacity at prices other than the price fixed by the marketplace. By legislating capacity prices, New Jersey has intruded into an area reserved exclusively for the federal government. Accordingly, federal statutory and regulatory law preempts and, thereby, invalidates LCAPP and the Standard Offer Capacity Agreements."

This brings into the question of a state being able to set prices that would influence dispatch of the electric market. USEPA must address this concern from a legal perspective.

In addition, the assumption that dispatch of NGCC plants will offset dispatch of coal-fired EGUs must account for the lower efficiency of coal-fired EGUs when cycling or operating at a lower capacity. Baseload plants operate most efficiently at their optimum CF, as they do not have associated "fast ramp" capabilities like simple cycle combustion turbines. An example of this is shown in Figure 2 (below). This technical issue was not addressed in the USEPA proposal, and conflicts with the USEPA assumptions for heat rate improvement in Building Block 1.

FIGURE 2[8]



The USEPA requested comment on whether "standards of performance for [affected sources]" is reasonably read to include emission performance level because doing so helps to define obligations under the plan. States can limit emissions from a facility in order to protect air quality. The dispatch, re-dispatch, or determination of which facilities must operate for reliability purposes is under the purview of FERC, not the state. This leads to a quandary, how does a state force the dispatch of lower CO_2 emitting facilities? Interestingly enough, what the USEPA is implying in the proposal for a state to implement is beyond the USEPA's statutory authority as well.

The USEPA also requested comment on whether the responsibility to achieve the emission performance level should be assigned solely to EGUs. While this may be possible, it does lead to some questionable scenarios. One such scenario is when a regulated unit is subject to a System Support Resource Agreement (SSR) that requires a unit to operate to maintain system reliability (Appendix G, FERC Dockets ER14-1242 and ER14-1243, ER14-2180, and ER-1725).[9] Currently, Michigan has three power plants in the Upper Peninsula that are subject to an SSR Agreement: the Presque Isle Power Plant, the City of Escanaba Plant, and White Pine No. 1.

If a unit cannot run because of a CO_2 limit, how would this interact with a SSR ordered by FERC? The state has no control over dispatch or SSRs. The USEPA should explain how the interrelationship between CO_2 dispatch and a SSR order could work under this rule.

COMBINED CATEGORIES

The USEPA requested comment on combining two existing categories, steam EGUs and combustion turbines, into one for affected EGUs. This concept could be accommodated by allowing this approach in a state plan as provided flexibility, but without making it mandatory. This would allow shifting or dispatch of resources within a system or category treated as a system: e.g., municipal electric utilities within a state.

Michigan does not object to combining the categories, but questions how this could affect state goals. State energy supplies from steam EGUs and combustion turbines are not homogenous among these two categories and vary even further from state to state. If the USEPA allows the states full flexibility, then the state would be able to decide how to average emissions from these two categories in order to meet the required emission goals.

The USEPA proposes using all four building blocks for BSER. There is one statement in that discussion that is incorrect: "In the large and highly integrated electricity market, where electricity is fungible, and the demand can be met in many ways…." The assumption of integration on a state level is incorrect when applied to Michigan, a state of two peninsulas. Electricity is fungible (one unit is the same as another unit) but our market is not highly integrated between peninsulas. The two peninsulas have very different energy supply networks and are, for the most part, separate. The Lower Peninsula is serviced (managed) by two RTO's. For reliability purposes, Michigan's Upper and Lower Peninsulas are each treated as individual local resource zones (Zones 7 and Zone 2) by MISO. The grid interconnections of the Upper and Lower Peninsulas are also fed by separate system tie lines in different states (Wisconsin, Ohio, Indiana, as well as the Province of Ontario). To further complicate the assumption, as already described, not all generating capacity in the state is available to Michigan customers nor regulated by the Commission. Therefore, the assumption of integration and fungibility simply does not hold true. This leads to the conclusion that the four building blocks are not "fungible" and there must be some accommodation to the calculation of goals to address the reality of the energy supply market and transmission constraints in Michigan. The USEPA needs to recognize the complexities of the existing electric market structure and allow states the time and flexibility in crafting a viable approach to meet reduction targets. The USEPA further states that integrated generation, transmission, and distribution networks create this fungibility. Fungibility could occur with major capital improvements but will require adequate time not provided for in the proposal.

INDIVIDUAL STATE GOALS

The USEPA solicited comment on whether they should incorporate greater consideration of multi-state approaches into the goal-setting process and how potential cost savings should be considered. Costs and a multi-state approach should be separated into two different issues as Section 111(a)(1) clearly states:

> The term "standard of performance" means a standard for emissions of air pollutants which reflect the degree of emission limitation achievable through the best system of emission reduction which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) the administrator determines has been adequately demonstrated."

If multi-state agreements are a path toward to meeting the state goals, it should be left to the participating states to make the economic determination that such an agreement is in the interest of the ratepayers. While the CAA does leave discretion to the Administrator, such economic consequences are so state-specific that it is beyond the USEPA's ability to make those decisions. Therefore, the requirements should be limited to meeting the required emission reduction goals.

FORM OF STATE SPECIFIC GOALS

The USEPA requested comment on the form of state-specific goals. The rate-based goals allow for flexibility with respect to changes in electricity demand, but in order to adequately assess the best system of administering a state program, the ability to convert those goals to a mass-based system is extremely important. A mass-based conversion would allow the state to determine strategies to provide for the least cost alternatives for meeting the required goals. In such a conversion, certain principles should apply; simplicity, allowance of averaging among "affected sources", and ability to convert adjustments that would automatically be provided for under a rate-based system. The same formulaic conversion could be applied to any adjustment so that only the state's methodology in demonstrating attainment of the goals would change, not the intent and implementation of the rule. Any adjustment to the "electricity demand projection" would have to be justified.

Michigan would also like to point out that the rate-to-mass conversion methodologies described in the Translation of the Clean Power Plan Emission Rate-Based CO_2 Goals to Mass-Based Equivalents TSD are inconsistent with the calculation of the rate-based goals discussed in the June 2014 proposal. In calculating rate-based goals, the USEPA added generation from Building Blocks 3 and 4 to 2012 fossil generation in the denominator, while in the TSD, generation from Building Blocks 3 and 4 replaces some of that fossil generation. For states considering "existing affected sources" only, the TSD approach results in a lower amount of generation, and thus a more stringent mass-based goal, than if the USEPA had added generation from Building Blocks 3 and 4 to 2012 fossil generation to calculate the Mass Equivalent Generation Level.

EMISSION RATES

The USEPA requested comment on nationally uniform emission rates for particular types of affected EGUs. Uniform emission rates are not feasible for existing sources. Unlike end-of-pipe controls of criteria pollutants, there is no technological solution that would lead to a uniform emission rate given the myriad of boiler designs, ages (vintage), and efficiencies. It would be impracticable and unrealistic to establish one emission rate for a given class or size of existing EGUs.

EMISSION RATE ADJUSTMENTS, EXPRESSION OF GOALS

The USEPA requested comment on net energy output (proposed) and gross energy output. The current reporting of CO_2 emissions from EGUs is required by 40 CFR, Part 75 to be in gross energy output and the proposed EGUs' CO_2 emission limits are expressed as net output. The USEPA did not propose a methodology for how any adjustments in net output would be modified for reporting in 40 CFR Part 75. Net output fails to account for broad discrepancies of parasitic loads to the EGUs. An example of this would be comparing the gross CO_2 lbs/MWh from an EGU with a wet sulphur dioxide control device to one with a dry scrubber. If all other things are equal, the EGU with a wet scrubber will have a higher carbon intensity than the dry control device, thereby skewing the net rate. This would be magnified with multiple or very large units in a state's generation mix. The goal calculations should be based on gross output for the EGUs or there should be a provision in 40 CFR, Part 75 for reporting net output if this is what the USEPA determines to be appropriate.

The USEPA should consider allowing an "alternative compliance payment" if a state will be unable to meet its interim and final goals. This payment could be made if a state adequately demonstrates that meeting the final goal is technically infeasible, given the circumstances and characteristics of the state's electric industry. The USEPA could use these payments to fund clean energy projects throughout the country to offset the retained emissions in the states making the alternative compliance payments.

Rate-Based Demonstration

The USEPA should be aware that in some states, like Michigan, there are elements of the electric industry that are unregulated and therefore a number of load-serving entities (LSEs) or IPPs do not fall under the jurisdiction of the Commission. The Commission cannot use its regulatory authority to bring the operations and cost recovery of these entities into alignment with a state plan that uses a mass-based approach. In fact, it is unclear how such entities could be included in a mass-based state plan. The MDEQ can put some CO_2 emissions stipulations into permits that would influence the LSEs' plant operations in a rate-based plan. The USEPA should provide guidance for states that have partially or fully deregulated electric sectors on how such states could comply with their Section 111(d) emission reduction obligations in a mass-based plan. A similar situation occurs with municipal utilities, which run primarily coal-fired plants. The Commission has no regulatory authority over their operations or cost recovery; therefore, it is difficult to envision how such utilities could be included in a mass-based state plan.

Redispatch of NGCC

Michigan's IOUs are market participants in one of two RTOs (MISO or PJM); and as such the electric generation resources are managed through a market-based system where power is bid into the market and bought back to provide supply to their customers. Based on the existing market-based approach, jurisdictional issues arise between the state regulators overseeing implementation of Section 111(d) and the RTOs managing the economic-based dispatch of all generation, including NGCC units. A fundamental change in this system would be necessary in order to account for re-dispatch of NGCC units, such as the implementation of a carbon price.

SAFETY VALVE

Reliability is a very real and prominent issue for Michigan as explained in the attached document Electric Reliability in Michigan: The Challenge Ahead, Public Sector Consultants, November 19, 2014 (Appendix H)[10]; therefore, although not proposed, the USEPA must consider a reliability "safety valve" for purposes of meeting electric demand in RTOs. An event, such as an outage at a nuclear power plant could greatly affect reliability and require the dispatch of more coal-generated electricity to prevent outages. A turbine loss or water leaks at a nuclear plant could mean an outage of up to a year. This would be an unforeseen catastrophic event and must be considered in the development and acceptance of a state plan. One of two ways could be used to accommodate such an event. The single year CO_2 rate could be adjusted or the normal averaging time could be lengthened to accommodate the outage adjustment. If the averaging time were lengthened, it would be necessary to adjust over a period of five or more years to accommodate reaching the normalized state goal. Such an approach would, in effect, keep generation resources critical to maintain reliability on the system until transmission solutions can be implemented to ensure retirements or curtailments do not create reliability constraints. The periodic state reporting could explain and verify the event, correction, and demonstrate the achievement of the goal over the allowed period.

The USEPA also asks for comment on an alternative assignment of responsibility under the portfolio approach. This alternative would place responsibility for achieving the state goals solely on the affected EGUs. Michigan must acknowledge the potential reliability issues in meeting future electric demand due to the closure of coal plants related to various USEPA rules [MATS, National Ambient Air Quality Standards (NAAQS), 316b, etc.]. MISO has determined a 3 gigawatt shortfall in generating capacity for what is needed for reliability and questioned reliability for Michigan.[11] Beyond the fundamental issues of experiencing a capacity/energy shortage due to lack of adequate supply when needed, the proposed Section 111(d) requirements for CO_2 reduction creates a jurisdictional conflict between federal agencies (USEPA and FERC). The North American Electric Reliability Corporation's recent study (November 2014)[12], looked at the potential reliability impacts of the USEPA's proposed rule and raised serious concerns about the proposed rule's impact on reliability (Appendix I).

The Federal Power Act empowers FERC to look at "just and reasonableness" when reviewing wholesale electric rates and market construct designs under RTOs, yet SIPs would be created to comply with the USEPA Section 111(d) standards with authority under the CAA.

FERC currently reviews and approves tariffs set forth by MISO (RTO) for "must run" EGUs due to reliability constraints on the electric grid. As such, these SSR contracts are determined by FERC to be necessary stop gaps to ensure reliable electric supply and would run afoul of any EGU (coal or natural gas) limited to run or required to retire due to CO_2 reduction targets contained within an approved state plan under Section 111(d).

Application of Building Block 2

Michigan has serious concerns about the application of Building Block 2. The assumption of NGCC dispatch at 70 percent could lead to reliability issues if implemented. Michigan has the most natural gas storage in the nation, but during the winter of 2013-2014 there were questions of being able to maintain an adequate supply of natural gas and price spikes in the state. When resources are used, they must be replenished and this is limited by pipeline transmission capacity. If Michigan with its large storage capacity was near a low point, this portends worse for other areas of the country.

There is a secondary issue that was not addressed in the RIA. The storage of natural gas and normal demand is met by gas that is purchased on long-term fixed price contracts. When situations arise such as the winter of 2013-2014, gas supply must be purchased on the "spot market" and prices that are orders of magnitude higher than fixed-price contract prices are paid. The impact of this affects the users of natural gas as well as the price of electricity generated using natural gas.

Infrastructure improvements will be needed to meet future project requirements. These improvements, such as natural gas pipelines, will be costly and require ten to 15 years to develop. As an example of infrastructure needs, two EGUs that were converted from coal to natural gas with nameplate capacity of 1,100 MW currently cannot operate because the gas transmission line that serviced them in the past is no longer in gas service but is now in petroleum service.[13] Significant infrastructure development will likely be required and will require capital and an extensive time frame. The USEPA proposal does not allow adequate time for these infrastructure improvements. Michigan urges the USEPA to adopt a phase-in schedule for Building Block 2 based on the fact that some states will require additional infrastructure improvements in order to support more use of existing natural gas-fired generation. This concept was discussed in the NODA.

Michigan believes that new NGCC could be considered as a basis for support for the BSER. The proposal does not indicate how new NGCC can be incorporated. Michigan supports including new NGCC generation as an option to meeting the goals.

In addition, the BSER for Michigan in Building Block 2 is more stringent than the emission limit for a new NGCC in the Section 111(b) proposal. The two proposals do not comport and should be aligned. In the Michigan BSER for Building Block 2, existing NGCC plants should be less stringent that the proposed Section 111(b) new source proposal, not more stringent.

Redispatch of NGCC

Michigan's IOUs are market participants in one of two RTOs (MISO or PJM) and, as such, the electric generation resources are managed through a market-based system where power is bid into the market and bought back to provide supply to customers. Based on the existing market-based approach, jurisdictional issues arise between the state regulators overseeing implementation of Section 111(d) and the RTOs managing the economic-based dispatch of all generation, including NGCC units. A fundamental change in this system would be necessary in order to account for re-dispatch of NGCC units. We suggest that the USEPA strongly consider a reliability "safety valve" for purposes of meeting electric demand in RTOs. Such an approach would in effect keep generation resources critical to maintain reliability on the system until transmission solutions can be implemented to ensure retirements or curtailments do not create reliability problems. The USEPA must consider that some of these units are on interruptible gas supplies and will not be able to operate if a shortage occurs.

Application of Building Blocks 3 and 4

Michigan should achieve, or come close to achieving the emission reductions set forth in Building Blocks 3 and 4 if it can also achieve reductions in CO_2 emissions equivalent to those in Building Blocks 1 and 2.

a. Building Block 3a - Michigan should be able to count the proposed 5.8 percent "incentive" for at-risk nuclear; however, Michigan believes that nuclear generation should be eliminated from calculation of the rate-based goals. As stated above, Michigan recommends USEPA consider adopting another methodology as a means to incentivize continued operation of existing nuclear assets. Possible methodologies include but are not limited to:

Consider all or a substantial percentage of generation from existing nuclear units and assume a more reasonable capacity factor reflecting forced/unforced outages in setting the standard. This would create a tangible incentive for states with nuclear to use for compliance purposes.

Remove nuclear generation from the existing rate setting formula, but allow states to reflect any retired nuclear units by removing lost generation from prematurely closed nuclear units from the denominator of the compliance rate formula.

b. Building block 3b - Michigan is required to have 10 percent of its electricity sales come from RE by 2015. Michigan is on track to meet this standard; however, the USEPA has not adequately described which RE resources will "count", both in terms of the energy source (biomass, incremental hydropower, etc.) and the facility's initial operational date. If the agency accepts the emission reductions from: 1) a wide variety of RE sources, and 2) all RE facilities that use the eligible energy sources, without regard to the facilities' construction dates as long as they are operating within the 2020 to 2029 timeframe, then Michigan should be capable of matching the USEPA's RE targets for the state and probably would not need to pass a more stringent RPS in the immediate future. However, a renewal of the RPS, possibly with greater stringency, may be warranted because there is the risk that if legislation does not replace our current standard, then Michigan's 2015 level of RE will slip below 10 percent from 2015 to 2030, making it more difficult for Michigan to meet its final and interim goals.

c. Building Block 4 - Michigan could achieve the reductions in Building Block 4 if: 1) the savings from all measures installed from 2012 to 2014, or (even better) from 2005 to 2014, are counted during the 2020 through 2029 compliance period; 2) the utility spending cap in the state statute is raised above two percent to allow funding for the capture of energy savings from cost-effective EE improvements that have higher upfront costs and/or longer payback periods.

As discussed previously, legislation may be necessary to increase the amount of RE or EE undertaken by utilities. This could be a lengthy process. Michigan again reiterates that in-state hydropower and pump storage upgrades, a zero-carbon energy source, should be counted towards CO_2 reduction efforts, as Michigan state law allows.

Reductions as proposed in Building Blocks 1 and 2 do not appear achievable as previously discussed. This presents a definite dilemma in that it would be assumed that short falls would increase the reductions from Building Blocks 3 and 4; however, this is without regard to technical or economic feasibility. The USEPA must explain how shortfalls in some blocks affect targets in other blocks.

a. Building Block 3a - Michigan could uprate its nuclear generation and move the generation incremental to the 2012 level into the denominator, assuming that the USEPA approves this incremental generation as a compliance measure. Michigan could also construct a nuclear plant and, assuming that it begins supplying electricity before 2030, count that new generation toward compliance with its final and interim goal. A Michigan utility is currently undergoing licensing procedures with the NRC for the construction of a new reactor. The utility has not made a decision to build and has stated such a decision would be influenced heavily by the finalized carbon regulations and relative cost of the generation it would provide.

b. Building Block 3b - Such levels of RE penetration would come at a cost and may require adjustments to utility system operations as well as transmission and distribution system improvements to accommodate additional RE resources on the grid.

c. Building Block 4 – If energy waste reductions are only counted after 2020, Michigan would be incentivized to repeal the current law creating utility mandated programs and not resume them until 2020. Eliminating energy waste is a stated priority of the administration; USEPA should not structure its final rule in such a way to penalize such action, as the proposed rule does.

Of additional concern for Michigan:

Michigan relies often on the Ludington Pumped Storage (LPS) facility due to the flexibility of operating the system and, in particular, its ability to ramp-up quickly. In addition to being a backstop to RE sources such as wind, LPS is also used during peak demand periods as an economic hedge to running more expensive generation (coal and gas units) or procuring spot market energy at a premium. In that instance, LPS acts as an energy storage system. In addition, it is important to note that the LPS facility is currently undergoing a six-year life extension and uprating project, which when complete in 2019, will result in an additional 420 MW of capacity. The additional capacity should count toward Michigan’s target.

The final rule should better reflect and acknowledge interstate and international trading of electricity. Michigan imports hydroelectric generation from Canada, and also has RE located outside the physical borders of Michigan. The final rule should allow for the purchase of RECs from other nations such as Canada.

STATE PLANS

Portfolio Approach

Michigan has an existing statute that requires 10 percent of electricity from RE by 2015 and 1 percent annual electricity savings. Given the success of this program and the fact that Michigan is ahead of schedule for meeting the 2015 RE goals, the portfolio approach should be one of the options available to states in the final rule. Michigan agrees that under this portfolio approach, the emission limits would be a combination of measures in addition to enforceable emission limits for the affected EGUs. A portfolio approach also allows for measures such as repowering or retirements. Michigan strongly supports the concept of a “state-driven” plan structure.

USEPA is also taking comment on authorizing state plans to adopt a portfolio approach, and to interpret the CAA as allowing that approach, including obligations that state plans could require the affected EGUs to be the sole entities responsible for achieving the emission performance level. While Michigan’s current statute is similar, but not exactly the same as the proposal, there is no certainty that Michigan’s requirements for RE and EE will be expanded beyond 2015. For these reasons, Michigan supports the concept of allowing the existing state RE and EE to count in state plans, but not mandating this requirement as part of the state portfolio plan. Michigan supports the concept of a state required plan for RE and EE meeting the commitments of goals under a Section 111(d) rule.

Plans with State Commitments

The USEPA is taking comment on a “state commitment approach” that would include requirements for entities other than the affected EGUs. Under this type of plan, the onus to implement measures should be on the state and should not be federally enforceable against the non-EGU entities. The CAA Section 111(d) states explicitly that the state must develop a plan to implement Section 111(d) requirements. Michigan agrees with the concept that a state commitment plan is within the statutory framework of the CAA. The choice of level of requirement of the affected EGUs and entities other than affected EGUs under such a plan should be left to the state to develop.

ENFORCEABILITY AND LEGAL ISSUES

The USEPA is soliciting comments on enforceability with respect to the regulated EGUs and other aspects of the state plan, should it contain a portfolio approach or select a mass-based approach. If Michigan were to adopt a state plan that assigned responsibility for attaining the required state goals, the plan would be enforceable both by the state and upon subsequent approval by the USEPA. This is the traditional approach of enforceability under the CAA.

Michigan has concerns about direct federal enforcement on third parties if a portfolio or mass-based approach is taken. To explain more fully, part of either of these approaches should require a CO_2 limit on the regulated EGUs, and the regulation of the EGUs would be presumed to also be federally enforceable. Michigan has concerns if some of the other obligations of the state plan, RE and EE, were viewed as federally enforceable against third parties. The state plan should be acceptable if the state has enforcement authority over the in-state third party entities. In a case where the state, and not the USEPA, has enforcement authority, it would be Michigan that would be held accountable for meeting goals that rely on the non-EGU entities.

The USEPA proposes to approve state plans based on four general criteria, the first of which is “enforceable measures that reduce EGU CO_2 emissions.” A plan that includes re-dispatch using Building Block 2 from a state where the grid is run by an RTO would not be enforceable. As noted previously, generation dispatch in Michigan is managed by MISO or PJM (not the state) based on security-constrained economic dispatch. Michigan does not decide which units are dispatched and does not have the authority to enforce re-dispatch to reduce CO_2 emissions. By proposing as the BSER a building block that many states, including Michigan, cannot enforce, the USEPA is proposing a method for reducing CO_2 emissions that the USEPA itself will not approve. That approach is irrational, and the proposed rule is therefore arbitrary and capricious.

Where the state plan includes emission limits for the affected EGUs, and when the sole responsibility for meeting the state goals are established with requirements for individual affected EGUs, it leaves little doubt that the state plan would be enforceable and the affected EGUs could be held responsible for meeting the goals in the state plan.

Under the portfolio approach, there are two different issues. The “utility-driven” portfolio approach seems to lead to federal enforceability for the affected EGUs. Under the “state driven” approach, the federal enforceability is not as clear. Michigan does not support federal enforceability for third parties in Michigan that are not part of the affected EGUs. Michigan believes this to be the responsibility of the state and enforcement on entities other than the affected EGUs should be the sole responsibility of the state.

With the mass-based approach, it would appear the flexibility and responsibility for meeting the required state goals would be left to the state. While responsibility would be accepted by the state in the plan submittal, it should also provide for contingency planning that would serve as a “backup” to the plan. The state plan should be allowed to serve as a “standard of performance” on its own, provided the state took responsibility for meeting the goals upon itself as an entity. The state’s responsibility for its plan should be allowed for the portfolio approach or the state plan with commitments approach. A mass-based approach backed by state commitments, typically enforced through state legislation, should be allowed as this would provide for state flexibility while assuring the state goals are met and verifiable.

As the USEPA pointed out in the proposal, consistent with the principle of cooperative federalism, the CAA supports providing flexibility to states to meet environmental goals. Measures provided for in Section 110 SIPs have been considered and implemented by states in the past in order to meet NAAQS. Section 111(d) does describe the process as “SIP-like.” Michigan agrees with this concept and supports that states have flexibility in selecting measures to meet the required state goals.

DURATION OF PERFORMANCE PERIODS FOR FINAL AND INTERIM GOALS

An interim goal is artificial and not explicitly or implicitly presented in Section 111(d) or Section 111 at all. Certainly interim measures show progress and should be present, verifiable, and at least state enforceable; however, it should be up to the state in the state plan to determine how interim goals will be met, as long as appropriate progress is being made as committed to in the state plan. The USEPA should develop guidance on what commitments and factors are required in the state plan to show interim progress. This would not require a firm 2020 target (or the problematic 2020-2029 averaging method), but rather measured progress toward the 2030 reduction goal.

The USEPA has proposed a multi-year performance period for single or multi-state programs. Michigan agrees that a multi-year performance period is appropriate given the transitions in generating technology, capital investment, and implementation of energy-saving programs. Even though Michigan has made recent large investments in increased transmission, and has one of the most robust natural gas pipeline structures in the nation, we believe significant new investment in Michigan's transmission and distribution infrastructure will likely still be needed to support alternative generation and increased natural gas use. This affects not just the cost of energy but also has significant implications for how quickly the State could comply. Moreover, if this is a concern for Michigan, we expect that states without the natural geology to allow for storage, or without large natural gas pipeline infrastructure in place will face even more severe constraints.

Allowing states flexibility in meeting the goal by 2030 is a laudable concept; however, it is a method that should be reconsidered. The interim goal is heavily weighted prior to 2020 with a very short time frame to meet that interim goal. There is no disagreement that forward progress must be met and in doing so, tracking and reporting that progress is appropriate, necessary, and helpful for all parties.

The interim goal as proposed is troublesome in part because not allowing RE and energy waste reductions to count prior to 2020 has the perverse effect of delaying implementation of those programs, which can lead to fewer total tons of CO_2 emissions being avoided. When a state has shown success in reducing energy waste, and there is political and public willingness to continue these programs, establishing a future date to wait for credit dis-incentivizes the need to continue or expand these programs until a future year when credit can be taken. There should be some programmatic method to allow credit towards the program goals for permanent reductions achieved from 2012 to 2020. In addition, to clearly articulating the date by which credit will be counted, it is essential that USEPA provide clarity on how credit will be determined in terms of calculating lifecycle savings and associated emission reductions for measures installed prior to 2020. These emission reductions from EE programs should be shown to be permanent, recurring into the future, and contributing to CO_2 reductions so long as the energy savings were quantified and verified through independent evaluation, measurement, and verification.

In the event that USEPA feels compelled to maintain an interim goal, 2025 would be more favorable than 2020. While Michigan does not agree with the concept of an interim goal, time is needed to make the proper adjustments and accommodation to shift generation to meet the USEPA required goals.

CONSEQUENCES IF ACTUAL EMISSION PERFORMANCE DOES NOT MEET STATE GOAL

The USEPA has requested comment on whether consequences should include a requirement to trigger contingency measures. A state plan should include contingency measures in the event the state goals are not met. There is an anticipation that the state plan would be met for development of RE and implementation of EE programs; however, these plans would be projections of anticipated gains that would reduce CO_2. Unforeseen events or obstacles to meeting those commitments could occur and there should be contingency measures identified to reduce CO_2 emissions and bring the state back on track to meet the required overall goals.

Separate from the lack of meeting state goals should be the recognition that a catastrophic event could occur such as the failure at a baseload generating plant. In order to maintain grid reliability it could be necessary to increase fossil fuel electric generation to meet electricity demand. Such an occurrence does not lend itself well to contingency plans since by the time such measures would be implemented the catastrophic event may be corrected. Such an event occurred in 2003 in Michigan's Upper Peninsula when a 345 MW coal-fired baseload plant was flooded due to the failure of a dam and went out of service for a period of time. The power loss was shored up by the import of very large diesel generators and running other EGUs in the area as baseload plants. An event such as a major storm could also affect wind farms or other types of facilities and a similar situation could occur. It is for this reason that the USEPA should be flexible in defining a catastrophic event and be specific on how to address such possibilities within a state plan.

Michigan supports the proposed three-year average for the final goal. As proposed, 2030 through 2032 gives the ability for the state to deal with fluctuations in energy demand and normalize demands due to weather variation.

OUT YEAR REQUIREMENTS

The USEPA requests comment on out year performance beyond 2030 of the state plan. Michigan assumes that much like a Section 110 SIP there would be a requirement to prevent "back sliding" or a decrease in meeting the Section 111(d) commitments. Unlike the Section 110 SIPs there would not be a possible future attainment negating the need for maintenance. It is assumed that where Congress developed Section 111(d) the requirements would not end but would continue into the future. Therefore, it would lead to the conclusion that state plan would not sunset.

FLEXIBILITY TO CHOOSE MASS-BASED OR RATE-BASED GOALS

The USEPA proposed flexibility between a rate-based goal and a mass-based goal for states. Michigan supports the concept of being able to convert from rate to mass to establish the state goal. Projecting the demand for electricity in a state 20 years from now cannot be done with accuracy. Technology and electricity demand can change quite dramatically over such as long horizon. For this reason and others, there may be hesitation to adopt a rate-to-mass goal conversion. If there is a provision for a mass-based goal conversion there must also be an ability to update the mass goal based on the conversion, should the demand for electricity increase differently than projected.

QUANTIFIABLE AND VERIFIABLE EMISSION PERFORMANCE

The USEPA requested comment on a process and schedule for implementing corrective measures if reporting shows the goals are not being met. The state plan should identify possible corrective measures similar to a nonattainment SIP. These measures could include new actions or ramping up measures already provided for in the state plan. There should be a two-step process in this plan where the state provides progress reports. Michigan prefers a glide path approach to meet the final goal. While the USEPA has stated verbally this is not provided for in Section 111(d), it should; however, be noted that the interim goal is not provided for in Section 111(d).

When a state does not appear to be meeting the path at a reasonable time before 2030; e.g., three or five years, the USEPA should ask the state which measures will be implemented to be on track to meet the 2030 goal. If the failure to meet the goal is close to the 2030 date, the state should be allowed a three-year average period to make necessary changes in the implementation plan so the goal can be met at that date and in the future.

The USEPA requested comment on the frequency of reporting performance. Annual reporting is appropriate provided that due to variations in power demand, tracking performance should be compared to a multi-year average. The reporting should be done electronically and could utilize the existing 40 CFR 75 database with minor modifications. In this manner, the data would be readily accessible to the USEPA and the state.

STATE PLAN COMPONENTS PLAN SUBMITTED

Michigan supports two possible approaches for a multi-state plan submittal. It should be up to the participating states to determine whether one plan would represent all participating states, or the individual state would submit its own plan. It is conceivable that states participating in a multi-state plan may do so through an interstate agreement, and this agreement might be referenced as part of the state plan. For a multi-state plan, there must be certain common specifications, a “common currency.” Without reference to common definitions and methodologies, there exists the potential for unequal quantification or double counting within the emission reduction calculation. Likewise, the participating states should use the same goal units, rate-based or mass-based, to avoid inequalities.

Michigan agrees with the USEPA's description of what is required under "Identification of Affected Entities and Plan Inclusion," with the exception of the mass-based conversion elements. To ensure consistency and acceptance of a state plan by the USEPA regional offices, it is incumbent upon the USEPA to provide the proper tools to translate from rate-based to mass-based goals. Michigan does not support requiring the state to use a proprietary model to make such a translation. Use of a proprietary model obfuscates the translation process and is not a transparent process as part of the rulemaking. The requirement of a proprietary model would make it impossible for some states to make this translation because of existing laws governing such transparency. Michigan supports a simplified method for this translation of rate-based to mass-based goals.

The new TSD for conversion of rate-based goals to mass-based goals is helpful, but does not lay out the criteria for approvability by the USEPA when submitted as part of a state plan. This guidance is still lacking.

FOOTNOTES

[1] Michigan's Public Act 295, known as the Clean, Renewable, and Efficient Energy Act, signed into law on October 6, 2008, established a Renewable Energy Standard (RES)/ Renewable Portfolio Standard (RPS) for the State of Michigan.

[2] *Sierra Club v. Costle*, 657 F.2d 298, 326 (D.C. Cir. 1981).

[3] There is significant unrecovered book value of existing power plants that may retire due to the rule as well as in new power plants and other expenditures on energy efficiency, renewable energy, natural gas infrastructure, and other infrastructure that are necessary to meet emission requirements and maintain resource adequacy in the state. According to the Midcontinent Independent System Operator, Michigan currently has a projected capacity shortfall of 3 gigawatts in 2016 due to USEPA Mercury and Air Toxics Rule compliance and other factors. The ability for customers to absorb the costs of new and existing investments during a period of minimal load growth is not a trivial matter. The importance of this is underscored by the lack of reward in the rule, in fact the punishment in the rule as currently proposed, for Michigan's commitment to diversifying its electric generation in the midst of an especially severe economic crisis in which demand actually shrank. In addition, there are practical constraints in implementing these changes at such an accelerated pace.

[4] Average electric rates in the East North Central Region (Energy Information Administration data for May 2014), and carbon intensity as conveyed in the proposed rule

[5] We note that different, higher goals would be required if calculated using the technical support document (TSD) or regulatory impact analysis (RIA) documents accompanying the proposed rule.

[6] Notably, this does not include the Ludington pumped storage facility with a capacity of 1871 megawatts. Ludington is a unique resource that compliments renewable energy and other carbon-free resources such as nuclear power by providing energy storage of carbon neutral electricity, while also offsetting the need for additional plants to come on line in the peak periods.

[7] http://www.ferc.gov/legal/court-cases/opinions/2014/13-4330.pdf, New Jersey Court Case

[8] Source: AEP Building Block One, Heat Rate Improvements for Coal-fired Power Plants, August 2014

[9] Presque Isle Power Plan System Support Resource (SSR) Agreement [filed by Midcontinent Independent System Operator (MISO)], Federal Energy Regulatory Commission (FERC) Docket No. ER 14-1242 and ER 14-1243.
FERC weblink: http://elibrary.ferc.gov/idmws/file_list.asp?document_id=14241812

City of Escanaba SSR Agreement (filed by MISO) FERC Docket No. ER 14-2176 and ER 14-2180
FERC weblink:
http://elibrary.ferc.gov/idmws/file_list.asphttp://elibrary.ferc.gov/idmws/file_list.asp?document_id=14225712

White Pine No. 1 SSR Agreement (filed by MISO) FERC Docket No. ER 14-1724 and ER 14-1725
FERC weblink: http://elibrary.ferc.gov/idmws/file_list.asp?document_id=14205257

[10] Electric Reliability in Michigan: The Challenge Ahead, Public Sector Consultants, November 2014.

[11] Transmission and Reliability Impacts due to the proposed EPA regulations: A Preliminary Assessment (Powerpoint presentation), MISO, Planning Advisory Committee, November 12, 2014.

Analysis of EPA's Proposal to Reduce CO_2 Emissions from Existing Electric Generating Units, MISO, November 2014.

[12] Potential Reliability Impacts of EPA's Clean Power Plan, Initial Reliability Review, North American Electric Reliability Corporation, November 2014.

[13] Information obtained during a verbal conversation with representatives of Consumer's Energy.

<u>ATTACHMENTS</u>

Attachment 1 **Current Steps to Promulgate Michigan Air Rules**

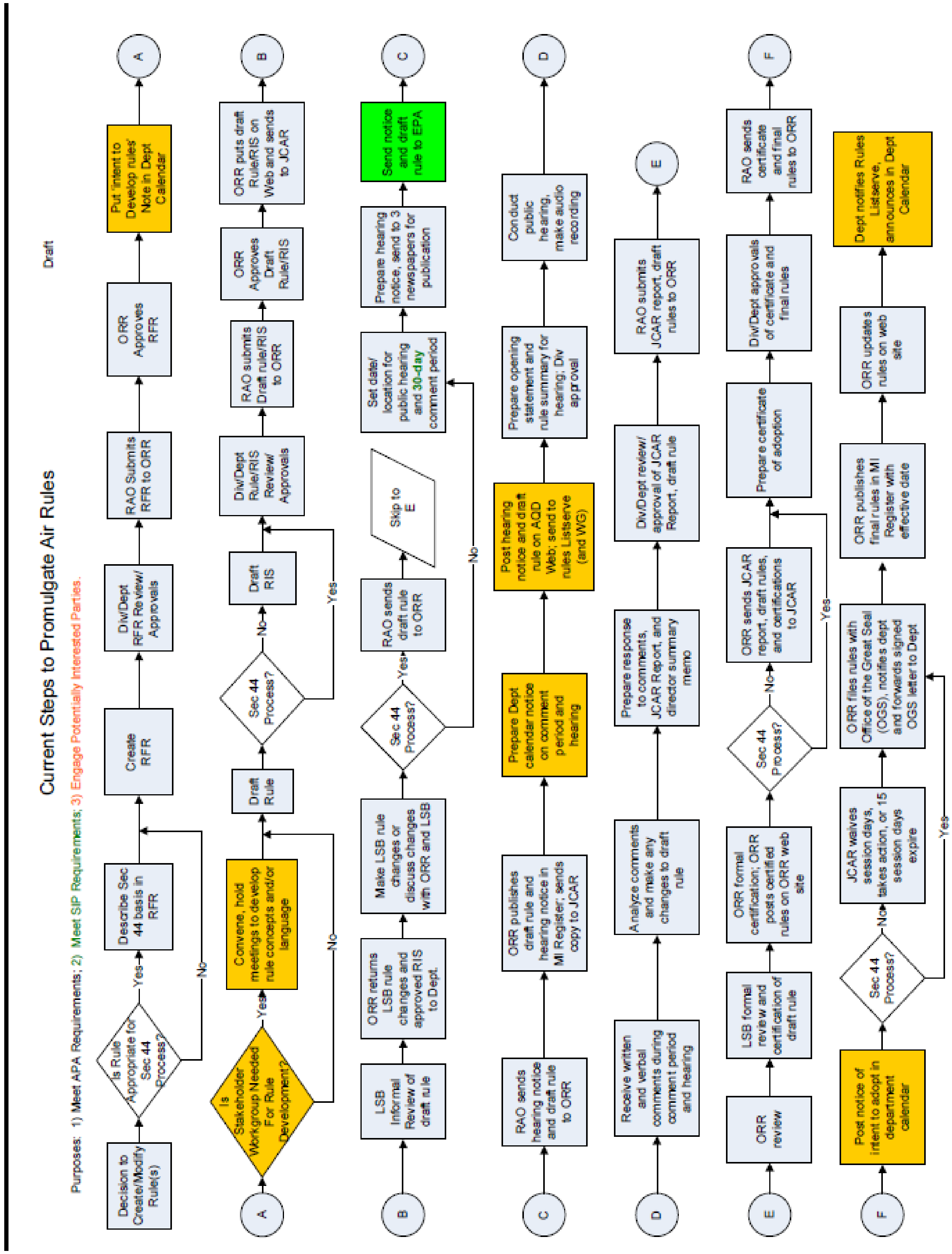
Attachment 2 **Michigan's 3-year Average Goal Calculation Using Years 2010-2012**

Attachment 3 **List of Michigan Natural Gas Generation Units (Simple and Combined Cycle)**

Attachment 4 **Michigan's Natural Gas Supply and Storage History**

Attachment 5 **Michigan's Nuclear Unit Data from EIA (2011 through 2013)**

Attachment 1
Current Steps to Promulgate Michigan Air



Attachment 2
Michigan's 3-year Average Goal Calculation Using Years 2010-2012

Step 1. Michigan's 2010 - 2012 state fossil emission rate

2010-2012 Rate (lbs/MWh)			2010-2012 Mass (lbs)	2010-2012 Generation (MWh)				Capacity	Starting Covered Fossil Rate (lbs/MWh)
A	B	C	D	E	F	G	H	I	J
Coal Rate	OG Steam Rate	NGCC Rate	Other Emissions	Coal Gen	OG Steam Gen	NGCC Gen	Other Gen	NGCC MW	
2,215	1,523	986	2,371,273,399	59,130,784	614,177	13,262,462	3,218,196	5,008	**1,933**

Step 2. Block One - Heat Rate Improvements at: **6%**

2010-2012 Rate (lbs/MWh)			2010-2012 Mass (lbs)	2010-2012 Generation (MWh)				Capacity	State Goal Post Block 1 (lbs/MWh)
A	B	C	D	E	F	G	H	I	J
Coal Rate	OG Steam Rate	NGCC Rate	Other Emissions	Coal Gen	OG Steam Gen	NGCC Gen	Other Gen	NGCC MW	
2,082	1,523	986	2,371,273,399	59,130,784	614,177	13,262,462	3,218,196	5,008	**1,830**

Step 3a. Block Two - Redispatch of Existing NGCC to: **70%**

2010-2012 Rate (lbs/MWh)			2010-2012 Mass (lbs)	Generation (MWh)				Capacity	State Goal Post Block 2.1 (lbs/MWh)
A	B	C	D	E	F	G	H	I	J
Coal Rate	OG Steam Rate	NGCC Rate	Other Emissions	Coal Gen	OG Steam Gen	NGCC Gen	Other Gen	NGCC MW	
2,082	1,523	986	2,371,273,399	**41,861,113**	**434,801**	**30,711,509**	3,218,196	5,008	**1,580**

Step 3b. Block Two - Under Construction NGCC

2010-2012 Rate (lbs/MWh)			2010-2012 Mass (lbs)	Generation (MWh)				Capacity	"Under Construction" NGCC	State Goal Post Block 2.2 (lbs/MWh)
A	B	C	D	E	F	G	H	I	J	J
Coal Rate	OG Steam Rate	NGCC Rate	Other Emissions	Coal Gen	OG Steam Gen	NGCC Gen	Other Gen	NGCC MW	NGCC MW	
2,082	1,523	986	2,371,273,399	41,861,113	434,801	30,711,509	3,218,196	5,008	0	1,580

Step 4a. Block Three - "At Risk" Nuclear at 6%

2010-2012 Rate (lbs/MWh)			2010-2012 Mass (lbs)	Generation (MWh)				Capacity	"Under Construction" NGCC	Under Construction and "at risk" Nuclear	State Goal Post Block 3.1 (lbs/MWh)
A	B	C	D	E	F	G	H	I	J	K	L
Coal Rate	OG Steam Rate	NGCC Rate	Other Emissions	Coal Gen	OG Steam Gen	NGCC Gen	Other Gen	NGCC MW	NGCC MW		
2,082	1,523	986	2,371,273,399	41,861,113	434,801	30,711,509	3,218,196	5,008	0	1,827,909	1,543

'Step 4b. Block Three - Renewable Energy (RE) at 7.4% with 6% growth rate. (MI's RPS is 10% by 2015 and the regional RPS is 15%.)

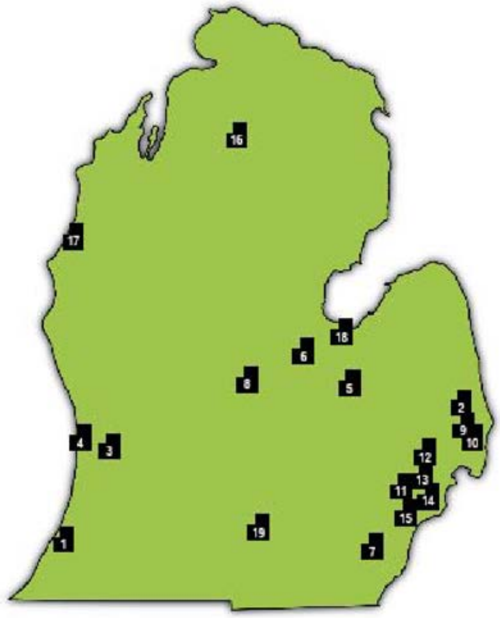
2010-2012 Rate (lbs/MWh)			2010-2012 Mass (lbs)	Generation (MWh)				Capacity	"Under Construction" NGCC	Under Construction and "at risk" Nuclear	Existing and New RE	State Goal Post Block 3.2 (lbs/MWh)
A	B	C	D	E	F	G	H	I	J	K	L	M
Coal Rate	OG Steam Rate	NGCC Rate	Other Emissions	Coal Gen	OG Steam Gen	NGCC Gen	Other Gen	NGCC MW	NGCC MW	MWh	MWh	
2,082	1,523	986	2,371,273,399	41,861,113	434,801	30,711,509	3,218,196	5,008	0	1,827,909	**8,055,859**	1,399

Step 5. Block Four - Energy Efficiency (EE) at 11.77%

2010-2012 Rate (lbs/MWh)			2010-2012 Mass (lbs)	Generation (MWh)				Capacity	"Under Construction" NGCC	Under Construction and "at risk" Nuclear	Existing and New RE	Avoided Sales Via demand-side EE	State Goal Post Block 4 (lbs/MWh)
A	B	C	D	E	F	G	H	I	J	K	L	M	N
Coal Rate	OG Steam Rate	NGCC Rate	Other Emissions	Coal Gen	OG Steam Gen	NGCC Gen	Other Gen	NGCC MW	NGCC MW	MWh	MWh	MWh	
2,082	1,523	986	2,371,273,399	41,861,113	434,801	30,711,509	3,218,196	5,008	0	1,827,909	8,055,859	13,263,617	**1,212**

Attachment 3

List of Michigan Natural Gas Generation Units (Simple and Combined Cycle)



	Power Plant Name	Capacity (MW)*	Major Pipeline
1	Covert	1,195	ANR
2	Greenwood	1,064	ANR
3	Zeeland	888	ANR
4	Holland BPW	159	CE
5	Thetford	234	CE
6	MCV	1,264	CE
7	Sumpter	340	DTE Gas
8	Renaissance	720	DTE Gas
9	East China	362	DTE Gas
10	Belle River	279	DTE Gas
11	Hancock	183	DTE Gas
12	Delray	159	DTE Gas
13	Northeast	80	DTE Gas
14	Mistersky	154	DTE Gas
15	DIG	790	DTE Gas
16	Livingston	160	DTE Gas
17	MPLP	154	DTE Gas
18	Karn	1,276	CE/DTE Gas
19	Triton	473	Vector
		9,934	

*Ventyx PowerBase

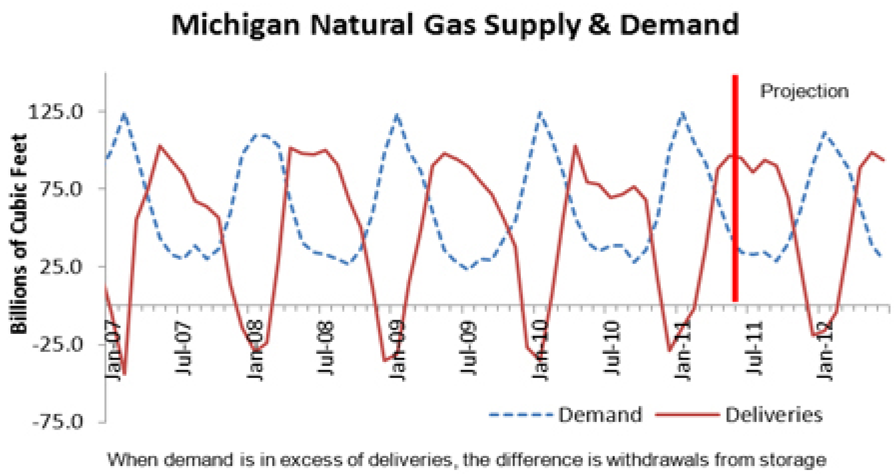
Data Source: Ventyx (an ABB Company), July 2014

Note: Units 1, 3, 6, 15, and 19 (Covert, Zeeland, MCV, DIG, and Triton) referenced above are NGCC. The remaining units are simple cycle.

Attachment 4

Michigan’s Natural Gas Supply and Storage History

http://www.dleg.state.mi.us/mpsc/gas/imgdisplay/anrstor3.htmConsumer demand for natural gas in Michigan is seasonal with higher demand during extreme cold periods for home heating purposes and lower demand during the warmer months. Natural gas supply, however, is available on a more uniform basis. Because of Michigan's excellent underground geological features, supplies of gas can be delivered on a more uniform basis. Michigan's underground natural gas storage facilities can balance receipts and deliveries for Michigan as well as provide winter deliveries to neighboring states. As shown in Michigan's Energy Appraisal, withdrawals from Michigan storage are sufficient in mid-winter months to provide gas supply for Michigan and neighboring states.

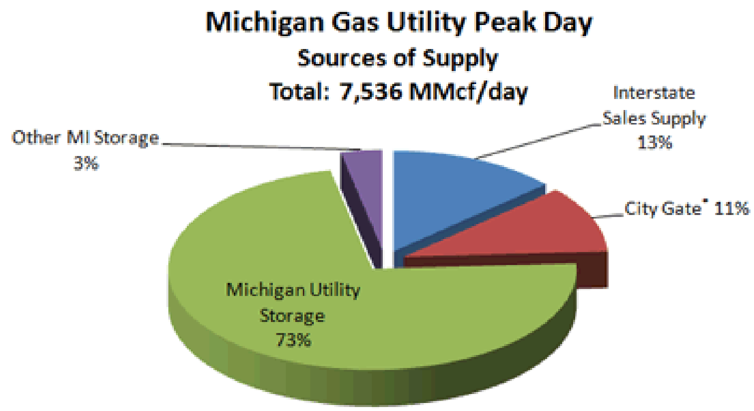


Link to Natural Gas Portion of MPSC Energy Appraisal

Michigan's available underground natural gas storage is significant. With about 690 billion cubic feet (19.5 billion cubic meters) of working gas capacity, EIA statistics show that Michigan has more storage than any other state. This storage provides for more efficient use of transmission pipelines that bring supply to Michigan utilities, and helps stabilize prices.

Storage is provided by distribution utilities and gas storage companies under rates and services approved by the MPSC (see Rate Book page). Interstate transmission pipeline and storage companies also provide storage services in Michigan under regulation of the FERC (see FERC Tariff Book page, or see FERC's list of pipeline companies).

Michigan's utilities design their purchases for a peak day demand of about 7.5 billion cubic feet (212 million cubic meters), of which over two thirds (5.5 billion cubic feet - 156 million cubic meters) is gas withdrawn from Michigan's storage fields, and the remainder is obtained from direct pipeline deliveries of gas from within and outside of Michigan.



As of October 2011
Source: data from utilities, utility Annual Reports, and MPSC Gas Cost Recovery cases for design (coldest) peak day.
View source data (PDF)

Michigan's gas storage is also useful as an alternative supply in an emergency. For example, in the spring of 1951, floods washed out a section of Michigan Wisconsin Pipeline Company's (now ANR Pipeline Company) pipeline in Kansas, shutting off its supply to Michigan for about a week. While it was being replaced, storage fields near Austin supplied Michigan's and Wisconsin's gas needs.

Michigan's storage also serves as a way of shifting summer supply to the winter. In the late 1940's demand for natural gas in Michigan grew faster than pipelines could be built to meet it. When a gas shortage occurred in Michigan in 1947, Consumers Energy (then Consumers Power) injected propane from 1,200 railroad tank cars into Michigan Gas Storage Company (then a new affiliated company) storage fields during the summer to prevent service interruptions the following winter.

Link to full size map

All but two of Michigan's 55 storage fields were once producing fields. They are located throughout Michigan's lower peninsula. They were converted to storage (the first in 1941) by drilling more wells and building pipeline facilities and compressor stations. Unlike producing fields, gas storage fields are designed such that their entire production can be cycled in and out of the field each year. The geologic structures that make up storage fields in Michigan have a high porosity, which makes them among the best in North America.

According to the MPSC's Storage Field Data Summary, most of Michigan's storage fields are located in the Niagaran formation. Other formations include Michigan Stray, A-1 Carbonate, and Reed City. Two of the storage fields are salt caverns. Michigan does not have any aquifer or LNG (liquefied natural gas) storage. The MPSC's Operations & Wholesale Markets Division keeps data on each of Michigan's storage fields.

Attachment 5

Michigan's Nuclear Unit Data from EIA (2011 through 2013)

Monthly Nuclear Utility Generation by State and Reactor

Home > Sources & Uses > Nuclear & Uranium > Data > Nuclear Power Plants > US Nuclear Generation of Electricity

Source: http://www.eia.gov/nuclear/generation/index.html

January through December 2011

State of Location and Reactor Name	Net Capacity MW(e)	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEP	OCT	NOV	DEC	Year-To-Date	
		Megawatt hours													
MICHIGAN	**3,947**	**2,603,488**	**2,308,236**	**2,866,243**	**2,936,459**	**3,010,204**	**2,884,057**	**2,940,121**	**2,928,263**	**2,328,764**	**2,304,753**	**2,815,778**	**2,963,101**	**32,889,467**	**95.1%**
Palisades	793	470,918	549,704	599,520	586,084	601,466	575,531	587,675	587,482	382,827	558,063	579,535	562,215	6,641,020	95.6%
Fermi 2	1,085	534,432	333,314	838,538	805,527	817,678	785,224	800,118	799,927	785,625	826,294	735,321	828,212	8,890,210	93.5%
D.C. Cook 1	1,009	763,244	672,326	595,339	740,216	764,494	737,850	758,280	756,366	382,122	102,632	701,034	742,434	7,716,337	87.3%
D.C. Cook 2	1,060	834,894	752,892	832,846	804,632	826,566	785,452	794,048	784,488	778,190	817,764	799,888	830,240	9,641,900	103.8%

January through December 2012

State of Location and Reactor Name	Net Capacity MW(e)	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEP	OCT	NOV	DEC	Year-To-Date	
		Megawatt hours													
MICHIGAN	**3,957**	**3,002,438**	**2,874,104**	**2,535,185**	**882,940**	**2,553,818**	**2,366,398**	**1,945,690**	**2,292,739**	**2,501,955**	**2,711,924**	**2,121,747**	**2,230,776**	**28,019,714**	**80.6%**
Palisades	803	520,384	560,994	559,117	70,773	337,644	223,603	379,584	232,642	572,715	598,924	516,978	604,855	5,178,213	73.4%
Fermi 2	1,085	834,658	777,846	656,219	-4,106	653,365	600,935	37,766	524,001	419,846	538,502	96,113	-12,853	5,122,292	53.7%
D.C. Cook 1	1,009	816,762	762,762	809,182	780,520	792,696	750,030	736,532	745,206	733,806	750,146	740,616	806,370	9,224,628	104.1%
D.C. Cook 2	1,060	830,634	772,502	510,667	35,753	770,113	791,830	791,808	790,890	775,588	824,352	768,040	832,404	8,494,581	91.2%

January through December 2013

State of Location and Reactor Name	Net Capacity MW(e)	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEP	OCT	NOV	DEC	Year-To-Date	
		Megawatt hours													
MICHIGAN	**3,957**	**2,791,910**	**2,388,312**	**2,620,531**	**1,826,588**	**1,533,456**	**2,309,981**	**2,609,391**	**2,679,670**	**2,345,864**	**2,178,083**	**2,577,556**	**3,059,481**	**28,920,823**	**83.4%**
Palisades	803	601,801	406,300	601,233	582,500	78,941	240,832	586,088	586,335	570,971	594,112	584,273	608,310	6,041,696	85.8%
Fermi 2	1,085	537,127	489,402	529,856	432,891	357,159	512,775	522,400	526,801	275,094	789,239	791,587	834,631	6,598,962	69.4%
D.C. Cook 1	1,009	811,340	733,668	649,964	0	270,112	763,808	774,142	767,182	739,256	784,802	774,310	781,560	7,850,144	88.8%
D.C. Cook 2	1,060	841,642	758,942	839,478	811,197	827,244	792,566	726,761	799,352	760,543	9,930	427,386	834,980	8,430,021	90.8%

APPENDICES

Appendix A Analysis of EPA's Proposal to Reduce CO_2 Emissions from Existing Electric Generating Units, MISO, November 2014

Appendix B Readying Michigan to Make Good Energy Decisions: Renewable Energy, Department of Licensing and Regulatory Affairs, Michigan Public Service Commission and Michigan Economic Development Corporation, Michigan Energy Office, November 4, 2013

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