Attachment A – Technical Comments

Below are additional comments from the State of Indiana pertaining to specific elements of the proposed rule. The comments below represent areas where Indiana would like to:

- Provide updated or corrected information to U.S. EPA,
- Express concerns regarding technical understanding,
- Provide additional technical information for U.S. EPA's consideration, and
- Seek clarification concerning U.S. EPA's intent.

The comments contained in this Attachment should in no way be interpreted as a tacit acceptance of the legality or policy propriety of the proposed rules. As indicated in the cover letter to this Attachment, the State of Indiana believes the proposed rules should be withdrawn. If U.S. EPA insists on finalizing the rules, Indiana respectfully requests that the following be taken into account.

I. Time frames

a. Indiana strongly feels that the 13 months U.S. EPA is allowing for state plan development is entirely insufficient for states to prepare adequate plans. Indiana's statutory rulemaking process requires a minimum of 1.5 years to fully promulgate a rule, and much longer for rulemakings that require extensive stakeholder involvement. Additionally, Indiana currently lacks the necessary statutory authority to implement and enforce Building Blocks 2, 3, or 4. Legislative action would be necessary for Indiana to contemplate the use of Building Blocks 2-4 in a state plan. U.S. EPA's proposed deadlines do not afford Indiana's legislature the time necessary to consider or act on the necessary authority considerations. The time frames, even with available extensions, are not long enough for the state to meet the requirements. The CAA generally provides states three full years to develop State Implementation Plans to address specific requirements of the Act. This proposal is far more complex than any State Implementation Plan developed by Indiana thus far. At a minimum, U.S. EPA should provide states five full years to prepare and submit a state plan under this requirement.

b. State statutes and U.S. EPA's regulations in 40 CFR 60.24 allow states and U.S. EPA to set less stringent standards or longer compliance schedules for existing sources when warranted, considering cost of control, remaining useful life of the facilities, location or process design at a particular facility, physical impossibility of installing necessary control equipment, or other factors making less stringent limits or longer compliance schedules appropriate. Indiana strongly feels that U.S. EPA has within its power the authority to extend the time frame of the 111(d) rule to a more reasonable time frame that gives both states and regulated industry a chance to plan and make changes in a safe, reasonable, and cost effective manner.

c. Indiana does not feel that the time frames proposed in the rule allow for any significant stakeholder process within the state. This creates even more challenges in formulating a state plan and in promulgating a state rule. The electric sector is a complex system that involves multiple governmental agencies at both the national and state level. No single governmental agency has the knowledge to develop and implement a technically and legally sound plan on its own. It is crucial that Indiana's various regulatory agencies have time to form a cooperative stakeholder group, along with the regulated community and citizens of the state, to complete the task of developing and finalizing a state plan. Failure to have an active and involved stakeholder process will likely result in an incomplete and flawed plan that will surely be subject to public and legal scrutiny.

d. Indiana also feels that the time frames proposed in the rule do not allow adequate time to devise, evaluate and, if beneficial to Indiana, deploy a regional program given the extreme complexities of the rule and how permanent and enforceable control measures will be developed and implemented across state lines. The difficulties encountered under a state only plan will also be present in the regional planning process. Additionally, there are added difficulties in dealing with multiple sets of state governmental agencies, as well as multiple state rules. The development, refinement, and review process of a regional plan across state lines will be difficult and require additional time beyond what is allowed under the proposed rule.

e. Based on consultation with its utilities, Indiana is concerned that EGUs will not be able to implement changes to their units in a reliable fashion by 2020. Indiana requests that U.S. EPA remove the interim compliance requirement to provide facilities with the ability to safely comply with the rule. If U.S. EPA needs the interim goal to demonstrate continuing compliance efforts are underway, Indiana requests that U.S. EPA revise the rule to require interim goals be met by 2025 at the earliest, to allow facilities making large scale and expensive changes to do so in a safe, reliable, and cost effective manner. Requiring facilities to make complicated and expensive changes within 3 years of the publishing of the rule puts the nation's electric grid reliability at risk.

f. The transmission grid will need to be expanded to accommodate the increased generation and movement of renewable energy between and throughout states. The Regional Transmission Organizations' (RTOs') planning and the resulting construction processes currently take between five and ten years for grid expansion. With new transmission lines crossing multiple states and jurisdictions, issues involving route selection, cost allocation, and construction could lengthen this process even more. Under the proposed rule, interim compliance begins in 2020. The rule will leave insufficient time for any new transmission lines to be built to support compliance in the early 2020s. New lines would have to be energized in 2019 for compliance in 2020. That would be four years after the rule is finalized and only three years after compliance plans are to be submitted to U.S EPA. There is simply not enough time to complete any new projects not already in the RTO planning process. Also, the RTOs use different calculation methodologies (e.g., for resource adequacy and transmission system capabilities) and capacity market constructs. These differences will have to be resolved to ensure effective regional compliance. Tariff changes will likely be needed, which will require approval from the Federal Energy Regulatory Commission (FERC). The resolution of these differences and changes will take a significant amount of time and more time than allotted for by the proposed rule.

g. Indiana lacks the regulatory authority to implement and enforce a plan that relies on the use of all four building blocks, based upon which the state goal was established. The proposed time frames do not allow sufficient time for Indiana to seek legislative action in order to be able to implement this rule. Indiana has a part time legislature that meets from January through early spring. Indiana requests that the time frames for plan development and implementation of the rule be extended by a minimum of five full years.

h. Indiana has not had adequate time to comment to U.S. EPA regarding the issue of converting a rate based goal to a mass based goal. This is a critical decision and Indiana is still in the process of evaluating the newly released guidance and will not be able to comment at this time. U.S. EPA has released numerous new technical documents during the comment period, including the rate to mass guidance within 30 days of the end of the comment period, which normally would result in an extension of the comment deadline. With U.S. EPA not extending the deadline on this issue, they stand to lose important input from stakeholders. Furthermore, due process dictates that stakeholders have all information at their disposal with sufficient time to review, evaluate, and prepare comments. For this reason, the comment deadline should have been extended.

i. By issuing a vaguely worded proposal that appears to provide large amounts of flexibility to states, U.S. EPA has created an opportunity for "gaming" the system. U.S. EPA has not provided detailed guidance on how to properly measure, document, and report compliance for any of the building blocks used in the BSER analysis. States are given flexibility to develop plans using undefined methods. There are multiple methods of quantification for nearly every measure that could be implemented under the building blocks that might be considered generally acceptable, each of which would likely derive very different results. If different states use different methods then one state could appear to have a substantially greater decrease in CO_2 emissions when they have not. This can lead to an unbalanced playing field with regard to cost of compliance and economic development. U.S. EPA needs to provide additional guidance and direction concerning complying with the rule to ensure that the rule is enforced equally from state to state and facility to facility. The time clock for states to develop state plans should not start until this final guidance has been released.

II. Reliability

a. Indiana is very concerned with long term reliability issues associated with the electricity grid. Indiana advises U.S. EPA to consider the North American Reliability Corporation (NERC) 2014 Long-Term Reliability Assessment[1]. The document states:

> *The electricity industry provided NERC with resource adequacy projections for the 2015–2024 assessment period. NERC independently assessed these projections and identified three key findings that will impact the long-term reliability of the North*

[1] http://www.nerc.com/news/Pages/Assessment-Identifies-Key-Long-Term-Reliability-Challenges.aspx

American BPS and materially changed the way the system is planned and operated. These key findings are:

1. Reserve Margins in several Assessment Areas are trending downward, despite low load growth.
2. Environmental regulations create uncertainty and require assessment.
3. A changing resource mix requires new approaches for assessing reliability.

The on-peak resource mix has recently shifted to be predominately gas fired: now 40 percent, compared to 28 percent just five years ago. This trend is expected to continue, as retiring coal, petroleum, nuclear, and other conventional generation is largely being replaced by gas-fired capacity and variable energy resources (VERs). The fundamental transformation of the resource mix—largely driven by environmental regulations, legislation, state and provincial incentives for additional VERs, and impacts of fuel prices, particularly for natural gas—presents new challenges for the electricity industry.

NERC also highlighted resource adequacy concerns, particularly in ERCOT, NPCC-New York, and MISO, as projections continued to reflect declining Anticipated Reserve Margins that fell below each area's Reference Margin Level during the short term (1-5 years).

The tightening of reserve margins increases the need to ensure all risks are accurately captured as policy and changing generation trends drive new potential risks to resource adequacy. New information projects an additional reserve margin shortfall in the North and Central Regions starting in 2016. Approximately 15% of coal capacity in the MISO footprint is projected to retire by 2016 to comply with the MATS. U.S. EPA's proposed CO_2 rule could place an additional 11 GW of coal capacity at risk of retirement in 2020.

By 2021, MISO's forecast is for reserve margins to fall from the NERC required 14.8% to 10.6% due to MATS. By 2020-2021, MISO estimates the reserve margins will drop to a negative 3.3% to comply with the additional requirements of CO_2 regulation. By 2023-2024, MISO's analysis shows reserve margins shrinking to negative 11.8%. In all cases, these estimates are caveated by recognizing that currently unplanned resources are likely to be made available as a result of actions by state commissions and load-serving entities. As planning reserves erode the probability of loss of load and reliance on Emergency Operating Procedures increase exponentially.

b. Indiana requests that U.S. EPA consider allowing states to adopt an emergency provision or "safety valve" that would allow carbon-intensive sources to operate beyond permitted emission limits in the event that grid reliability is compromised within a region. An example that could warrant a waiver of this type would involve extreme weather events that result in spikes in demand, such as the "Polar Vortex" experienced in the Midwest and East coast during winter of 2014. The cold weather not only increased electricity demand but also demand for natural gas. During the 2014 event, natural gas EGUs who had firm gas supply contracts did not receive the gas they expected because during periods of extreme demand, there was simply insufficient gas for these units to receive enough fuel to operate at high loads. Without natural gas units to provide reliable, base-load, lower-emitting CO_2 generation, electricity providers will have to rely on higher-emitting coal-fired units in this type of situation in the future. However, doing so could subject the company to prosecution under the CAA and could result in the company incurring millions of dollars in civil penalties, fines, and legal fees. Another example of this would be if a large nuclear unit must unexpectedly be taken offline, and there is no other reliable base-load generation other than coal in the area to replace the generation, then the state should be permitted to grant the coal unit a waiver so that it can operate to prevent regional reliability issues without incurring environmental liability for doing so. The proposed rule needs to take the concerns of grid reliability into account.

c. Indiana has serious concerns regarding the reliability of gas supplies to EGUs and households for home heating purposes. If there is a large increase in the amount of natural gas used for electric generation within a very quick time frame, which this rule anticipates will happen, then not only could this cause serious volatility in the price of natural gas, it could raise reliability issues associated with availability and distribution. In the absence of adding expansive new natural gas pipeline capacity, the current infrastructure in Indiana is limited and may not be able to handle the increased demand for natural gas to both residential customers and EGUs. Unlike with coal, the ability to store natural gas onsite at the plant is very limited, making interruptions to delivery service a very serious issue concerning grid reliability. Indiana is currently evaluating the infrastructure to determine the effect this rule will have on grid reliability. As a result of this rule, more and more EGUs are switching fuels to natural gas and this new demand has not been properly evaluated. A shortage of fuel capacity during cold Indiana winters could pose serious consequences for residential heating needs, as well as grid reliability. This would present a serious threat to public health and welfare for the citizens of Indiana.

III. Building Block 1: Heat Rate Improvements

a. Indiana feels that U.S. EPA has severely underestimated the net economic impact of Building Block 1. Indiana does not have sufficient regulatory authority to implement any additional building blocks under the proposed rule, and as a result, would have to try to implement an even more stringent version of Building Block 1 in order to meet the CO_2 emission rate required by the proposed rule. This increased stringency on coal-fired units could result in the limiting of allowable hours of generation from coal-fired units and/or the operation of coal-fired units at a loss. This could also result in premature closure of coal-fired EGUs and stranded costs for Indiana ratepayers. Additionally, this scenario could have very serious adverse impacts on grid reliability. Indiana strongly recommends that U.S. EPA work with FERC prior to proceeding with the proposed rule to address the extraordinary effects of this proposed rule on electricity grid reliability.

b. Indiana's generation portfolio is predominantly coal-fired; thus the 6% heat rate improvement applied by U.S. EPA drives a portion of the carbon emission reductions required for the state. While the data collection efforts of U.S. EPA are substantial, an important conclusion appears to lack justification. Page 2-28 of the Greenhouse Gas (GHG) Abatement Measures Technical Support Document (TSD) states that "if an EGU reduces heat rate variability, generally heat rate performance will improve." This conclusion appears to be supported by U.S. EPA's Figure 2-5 on the page following this statement. The regression analysis exaggerates this correlation because of the inclusion of what is clearly an outlier. Removing the outlier from the data set[2] yields a best fit line defined by y = 0.0009x – 3.7804. The outlier's impact, at a minimum, warrants further investigation on the appropriateness of its inclusion. Absent a strong reason for inclusion, the outlier should be removed from the data set. While reduced heat rate variability would appear to be an attractive characteristic, the correlation of it to overall heat rate improvement is inappropriate.

c. Indiana does not believe there is sufficient technical information available to show how the 6% heat rate improvement is achievable. U.S. EPA erroneously relied on the Sargent & Lundy[3] report and incorrectly applied cumulative improvements in a manner inconsistent with how the study was conducted. The study was intended as a guide for EGU operators to use to evaluate potential areas for heat rate improvements. In the study, it was assumed many times that the technology being evaluated was older or had not already been already replaced with more up-to-date technology. However, many Indiana utilities have already implemented the suggested heat rate improvements and should be given credit in the proposed rule for those improvements.

d. As part of its analysis to develop the 6% Building Block 1 heat rate reduction target, U.S. EPA relies on Continuous Emission Monitor (CEM) heat input and gross generation data from multiple specific generating units to determine what it believes are examples of significant step change improvements in gross heat rate. One of the generating units relied upon is Gibson Station Unit 1 in Gibson County Indiana, owned and operated by Duke Energy. U.S. EPA has erred in its reliance on the Gibson Unit 1 data because the CEM data for this unit is not independently representative for the analysis being conducted. First, prior to the spring of 2007, the Gibson Unit 1 flue gas exited a single common stack in combination with Gibson Unit 2. Per the CEM protocols of Part 75, heat input measurements from the single common stack were allocated to the individual units on a pro-rata basis using gross unit load. As a result, this CEM data does not independently represent the performance of Gibson Unit 1. Additionally, in the fall of 2007, Gibson Unit 1 was retrofitted with a new wet flue gas desulfurization system (FGD), including a new stack and completely new CEM system. It is inappropriate to compare CEM data

[2] The presented data set was approximated by visual interpretation and confirmed by replication of the presented best fit line.
[3] Sargent & Lundy Study SL-009597 January 22, 2009

before and after this event as the U.S. EPA protocol allows up to a 7.5% Relative Accuracy Test Audit limit for the flow monitor, and 0.7% limit for the CO_2 monitor (the measurements from the flow monitor and the CO_2 monitor are used in the CEM heat input calculation). Therefore, any changes in heat rate cannot be differentiated between the change in the CEM itself and any actual gross heat rate improvement, if any. This is only further emphasized by the fact that the improvement being sought is within the established measurement accuracy of the instruments, and should therefore be completely discounted anyway. Lastly, when the selective catalytic reduction (SCR) (in 2005) and FGD (in 2007) were added, the auxiliary power consumption for the unit increased, also increasing the net heat rate, even while the gross heat rate remained constant. Since U.S. EPA's analysis is only relying on gross generation and heat input data, it does not capture the change in the true total net heat rate for which compliance with the Clean Power Plan is required. The Gibson facility is one of the largest coal-fired EGUs in the United States and critical to the establishment of BSER. Indiana strongly encourages U.S. EPA to revisit the methods used to establish BSER for Building Block 1 as this may not be the only instance where such an important technical oversight was made.

e. Additionally, it is technologically impossible to apply all the improvements assumed under BSER and obtain the combined heat rate improvements outlined in the Sargent & Lundy study. For example, one of the technologies discussed are intelligent soot blowers. This technology could increase heat rate efficiencies by up to 1.5%, but on average would improve heat rates by 0.6%. Many facilities in Indiana already have intelligent soot blowers so there would be little improvement over the baseline, thus affecting the overall ability for facilities to achieve a heat rate improvement of 6% as established by BSER.

f. Furthermore, the reductions observed in the Sargent & Lundy case study were done on a facility operating at full capacity, thus giving maximum opportunity for any upgrades in equipment to be observed. It is very important to note that the heat rate improvements for the facility even with replacing outdated equipment at full capacity were only 4%. This is substantially lower than the 6% established by U.S. EPA. When facilities operate at less than maximum capacity, the heat rate improvements will not be as pronounced as they were observed in the Sargent & Lundy case studies. It is also important for U.S. EPA to factor in that Building Block 2 of the proposed rule would cause coal units to operate at less than the designed capacity and, thus have higher heat rates than they would at normal operating conditions.

g. Indiana requests that U.S. EPA consider the follow-up release by Sargent & Lundy[4]. In this paper, Sargent & Lundy provide summary comments regarding the study used by U.S. EPA in the proposed rule and are clear that the 6% heat rate improvements are in fact not attainable.

h. Indiana power plant operators are required to comply with a wide range of environmental requirements. Many commercial solutions employed to meet these requirements have a negative impact on the plant's net heat rate. Flue-gas desulfurization equipment, in particular, can degrade heat rate because they place significant auxiliary load on a plant.[5] Several Indiana plants have or will have added these significant power demands after the 2012 emissions base year (e.g., Ohio Valley Electric Corporation's 6 units at Clifty Creek and 2 units at NIPSCO's Schahfer station). The addition of these environmental compliance devices, among other devices with varying heat rate penalties, will exacerbate what were already unattainable heat rate improvement aspirations. The failure to explicitly recognize this real-world circumstance in the development of the goal by U.S. EPA suggests that it has been unreasonably discounted and in effect penalizes a state that is undertaking reasonable steps to meet other environmental mandates.

i. Many facilities in Indiana have already applied most of the basic improvements (low-hanging fruit) as outlined in the study. In conversations with utilities and the Indiana Utility Regulatory Commission (IURC) and the Indiana Office of Utility Consumer Counselor (OUCC), combined with the reported equipment improvements at EGUs, Indiana concludes that facilities under ideal conditions can only obtain 1-3% (less under reduced capacity usage or increased cycling) improvement in heat rates, depending on the facility and how many heat rate improvements they have already implemented prior to the release of the proposed rule. Given the nature of how the heat rate improvements are applied in the

[4] Appendix A – Letter from Raj Gaikwad Ph.D VP Sargent & Lundy to Mr Rae Cronmiller National Rural Electric Cooperative Association

[5] Heat rate penalty of 1.5% to 1.8% presented in Table 5-3 for Illustrative LSFO type scrubbers in U.S. EPA Base Case v 5.13 power sector modeling (www.epa.gov/powersectormodeling/docs/v513/Chapter_5/pdf).

proposed rule, EGUs do not get credit for the improvements made prior to 2012 and would still need to meet the 6% heat rate improvements to comply with the application of BSER for Building Block 1. The final rule should account for these variations in available heat rate improvements.

j. While U.S. EPA has relied on specific data regarding the CO_2 emissions, generation, and heat rates reported by EGUs through the Clean Air Markets Database to determine the overall efficiency potential of heat rate improvement (HRI) projects for existing units, U.S. EPA assumptions from this data are too broad and do not take into account unit-specific designs. Before U.S. EPA sets an efficiency goal for coal-fired units under Building Block 1 or state CO_2 targets, Indiana recommends U.S. EPA issue an information collection request (ICR) to all fossil-fuel fired EGUs and Load Serving Entities (LSEs), or electric utilities, to determine the following:
    - What HRI projects each coal-fired EGU has already installed.
    - The date of any such HRI installations.
    - Any operation and maintenance measures each coal-fired EGU already employs that assist the unit in operating more efficiently.
    - If the coal-fired EGU uses some of its fuel to supply steam to other customers.
    - If the coal-fired EGU is owned by a regulated utility, then the expected retirement year of the unit according to the utility's last approved depreciation study.
    - If a coal-fired EGU is owned by a merchant power producer or an unregulated utility, the planned date for the next major unit overhaul for the purpose of determining an appropriate retirement date.
    - For load-serving entities (LSEs), or electric utilities, the generation source, type, and location.
    - Capacity of generating units.
    - Power supplied through purchased power agreements in 2012 (or any historical years eventually used as a baseline for setting CO_2 targets).
    - Renewable Energy Credits (REC) inventories as of December 31, 2012 (or as of the end of any historical years used in the baseline for setting CO_2 targets).

   Indiana believes this information is crucial for U.S. EPA to know and consider, as it will provide the agency with specific heat rate improvements already conducted at EGUs and their expected retirement dates. Indiana notes that U.S. EPA has issued ICRs in past rulemakings to determine a reasonable and achievable emission limit that is technically and economically attainable for sources within a particular source category. Indiana recognizes that such a request will take time to execute and analyze the data, but such an endeavor is necessary to determine a realistic efficiency improvement goal for existing coal-fired EGUs and appropriate generation targets in each state.

k. Indiana asks U.S. EPA to clarify which method(s) states are to use to quantify and document the reduction in heat rates. If U.S. EPA is expecting that states use CEMs to monitor BtU/KWh, this expectation should be clearly stated within the rule. U.S. EPA should also take notice that under Part 75 (the Acid Rain Program); the accuracy reading for flow monitor is +/- 7.5%. With the variability of accuracy of the monitor being greater than the expected increased efficiency there could be technical issues demonstrating compliance.

l. Fuel switching should not be considered an acceptable method for achieving heat rate improvements. Technically speaking, changing from coal to natural gas fuel would actually raise heat rates. While the amount of CO_2 would decrease from a unit that switched to natural gas fuel, this is due to the amount of CO_2 released from the fuel and not due to an improvement in heat rates. Also, fuel switching may trigger New Source Review (NSR).

m. Given the time frame associated with the rule, it is important to note that heat rate improvements degrade in effectiveness over time and it is unlikely that facilities can maintain a fixed heat rate improvement for a 10 year period. Indiana requests that U.S. EPA consider revising the way that Building Block 1 is calculated over time to take into account the unavoidable degradation in heat rates even after all improvements are implemented.

IV. Building Block 2: Redispatch

a. Indiana is concerned that the implementation of Building Block 1 and Building Block 2 will work against each other. Under the proposed rule, U.S. EPA dictates that natural gas units operate more as base load suppliers and coal units will operate more as peak demand units, also called "peakers". Coal units operate more efficiently as base load units than they do as peaker units. If coal units are required to constantly change energy output then the units will be operating at less than peak efficiency and will not be able to obtain measurable heat rate improvements.

b. Indiana strongly suggests that U.S. EPA consult with FERC before trying to redefine the entirety of the electric market/dispatch. U.S. EPA is looking to complete and implement this rulemaking in a very short period of time. This is occurring at a time that EGUs are instituting control plans for other federal rulemakings. The electricity market can be volatile, and massive changes in the capacity and distribution of electricity could have major implications on the market. By incorporating FERC into the rule development process, U.S. EPA will have a better technical understanding of the important subtleties associated with electricity dispatch and appropriate timeframes for changes to occur.

c. Indiana is concerned that not all NGCC plants will be able to operate at a 70% capacity factor as proposed by the application of BSER under Building Block 2. Based on consultation with electric utilities in Indiana and surrounding states that run NGCCs, there is concern whether older facilities will be able to run at 70% capacity factor due to the age of the equipment and the required maintenance. Some NGCCs have been built using equipment from older coal units and as a result are not as efficient as newer units.

d. Indiana believes that U.S. EPA's assumption that NGCC plants are capable of operating at a 70% capacity factor overestimates capabilities of Indiana's NGCCs. In the year 2012, natural gas prices were at record lows[6]. Natural gas powered EGUs were able to sell power to RTOs at lower prices than coal-fired EGUs and had a larger piece of the power sector. It was also a very hot summer in Indiana[7], and energy usage was above normal levels. Even under these conditions, in which there was a financial advantage to maximize natural gas power, NGCC capacity usage in Indiana was only at 53% when averaged between all the NGCC units. This indicates that BSER for Indiana NGCCs should be closer to 53% than

[6] U.S. Energy Information Association - http://www.eia.gov/dnav/ng/hist/rngwhhdm.htm
[7] National Weather Service – NOAA - http://www.crh.noaa.gov/ind/?n=localcli

70%. The Noblesville[8] facility is a former coal-fired unit converted to a NGCC unit by the addition of combustion turbines, and is less efficient.[9] The Noblesville unit ran at a 29% capacity factor in 2012, despite the favorable natural gas price conditions of that period. While new NGCCs built in Indiana would most likely be able to operate at a 70% capacity factor and help Indiana reach the BSER determination, this would require Indiana to bring all new NGCC units in under both Section 111(b) and 111(d) to be able to meet the BSER. It is unclear whether a facility can be regulated under both elements of Section 111 and it most certainly was not the intention of the CAA to force states to build new facilities in order to meet BSER requirements under 111(d).

e. Requiring NGCC EGUs to operate at a 70% capacity factor could create an enormous economic disadvantage to ratepayers. The situation could be very problematic if natural gas prices increase sharply because the cost to operate a NGCC would also increase. Such units would have to bid into a wholesale RTO market at zero cost (sometimes called a "must run" unit) in order to ensure that they are dispatched by the RTO at a 70% capacity factor. In a traditionally-regulated state like Indiana, the actual costs to operate the NGCC unit would be paid for by ratepayers. Therefore the ratepayers would be paying higher costs for this energy rather than being able to obtain cheaper energy in the wholesale market.

f. U.S. EPA used nominal nameplate capacity when determining the capacity for EGUs in this proposed rule. Indiana believes summer peaking values should be used, as they are a much more accurate measure of an EGU's capacity.

g. U.S. EPA needs to be conscious of any possible constraints regarding dispatch of less CO_2 emitting units. Under Building Block 2 RTOs would be expected to dispatch the lower CO_2 intensive energy first. This could result in facilities that produce energy at a lower CO_2 rate being called on to dispatch more frequently than in the past and as a result exceed limits that could trigger NSR.

h. Indiana is concerned that U.S. EPA has not properly taken into account the costs associated with the increase of natural gas usage. While U.S.

[8] Noblesville is a 1950s-era coal-fired plant that was converted in 2003.
[9] 2012 FERC Form 1 reported net heat rate of 8520 Btu/kWh.

EPA estimated a modest increase in natural gas costs, an increase in delivery costs was not factored in. In some states, the delivery cost makes up more than half the costs for the fuel.

i. Indiana is assuming that when a new NGCC unit goes online after 2016-2017, that unit will be subject to 111(b) and not subject to 111(d). Through conversations with U.S. EPA staff, it has been conveyed that states will have the option to include new NGCC units into the 111(d) planning process, thus making them subject to 111(d) standards. In order to prepare a compliant state plan, Indiana needs to see this matter explicitly addressed in the rule, including how states can avoid legal pitfalls associated with regulating affected entities under both elements of Section 111 (new and existing).

j. Indiana urges U.S. EPA to consider allowing states to obtain credit towards the determination of the state rate goal when purchasing power from NGCCs from another state. This would be similar in implementation as proposed in Building Block 3 for renewable energy.

k. The implementation of this building block is challenging for a state to implement on its own. In the Midwest, electricity is dispatched by RTOs, not individual states or power companies. **Indiana does not have regulatory authority to control the dispatch of electricity within its own borders, let alone on a regional basis, and thus lacks the authority to implement Building Block 2.** Even if the state were to establish the authority to mandate dispatch of electricity from NGCCs at a certain level of capacity, implementation would have to be conducted by an RTO, not the state. Therefore, Indiana would not be in a position to properly oversee and enforce implementation, or ensure adequate recordkeeping.

l. The only manner in which EGUs have the ability to influence the dispatch of electricity revolves around the price at which the electricity is bid for dispatch. EGUs may have to bid on natural gas electric generation at a loss to ensure that the RTO dispatches it over coal in order to ensure a 70% utilization rate. This will create a much larger economic impact on the ratepayers and utilities than is currently used in costing information by U.S. EPA in the proposed rule.

m. Indiana is concerned about the prospect of our nation becoming too reliant on a single source of fuel (i.e. natural gas) to supply the majority of its energy generation. A nation highly dependent on one resource becomes a nation overly protective of a critical chokepoint and the economic, political, and societal implications of that dependency. Natural gas has a long history of price volatility. To the extent our nation becomes more dependent on natural gas, the short, medium, and long term vulnerabilities of natural gas resources must be realistically examined from the perspective of the electric industry, the nation, emerging international markets for liquefied natural gas exports, and, most importantly, the consumer. In its apparent determination to wean the country off coal, through this and other rulemakings, U.S. EPA could transition the country to a natural resource even more vulnerable to disrupting vast segments of the nation and the economy. U.S. EPA should re-consider its rule to recognize the value of a more robust and varied fleet of fuel resources throughout the country, taking full advantage of each state's relative ability to take advantage of the resources readily available to it. Thoughtfully employed fossil fuel resources will remain an important part of our nation's energy mix as part of an "all of the above" strategy, even as they are supplemented by increasing levels of nuclear and/or naturally replenishing resources in locations where they are more abundant (e.g. solar, geothermal, hydraulic, tidal, wind, etc. each have areas where they are most practical).

V. Building Block 3: Renewable Energy

a. Indiana recommends that U.S. EPA reconsider the methodology used to calculate renewable energy (RE) targets for states under Building Block 3. When calculating RE potential, U.S. EPA relied in part on a regional RE growth factor calculated using the Renewable Portfolio Standards (RPS) of states within that region, which was then applied to each state in that region, whether that state had an RPS in place or not. This has the potential to make renewable energy targets very aggressive in some states that have less RE potential, as well as no enforceability, and could result in unattainable renewable energy targets in those states. For instance, in the proposed rule, Indiana is a member of the North Central region, along with eight other states in the upper Midwest. Of these nine states, three (Indiana, North Dakota, and South Dakota) have non-binding renewable portfolio goals, while the rest have binding RPS. Therefore, the regional growth rate applied to Indiana was largely based on the renewable potential of other states. Further, within the North Central region, states like North Dakota, South Dakota, and Minnesota have substantially larger wind speed potential than Indiana, as shown in the National Renewable Energy Laboratory's (NREL) Annual Average Wind Speed map, yet these states are still grouped together in the same region for RE potential. However, the RE potential from wind speed is very different. At 80 meters high, around half of Indiana has an annual average wind speed of 6.5 meters per second (m/s), whereas the majority of areas within both North and South Dakota show an annual average wind speed of 8.5 m/s[10]. Because these states are grouped together for part of the RE calculation, it results in a higher calculated RE target for Indiana than is actually achievable, which in turn makes the state CO_2/MWHr goal rate lower than what is actually achievable. Further, each state with an RPS in place defines elements within their programs very differently. According to the Energy Information Administration's (EIA) Annual Energy Outlook 2013, "Under [RPS], each state determines its own levels of renewable generation, eligible technologies, and noncompliance penalties[11]." Therefore, using a regional approach, without taking into account the considerations detailed above that relies in part on an average of RPS goals within those regions in order to calculate RE targets for states, is unreasonable and untenable.

State Renewable Energy (RE) Generation Levels for State Goal Development as they exist in the proposed rule are as follows:

		Proposed Goals		Alternate Goals	
State	2012 (Percent)	Interim Level (Percent)	Final Level (Percent)	Interim Level (Percent)	Final Level (Percent)
Illinois	4	7	9	6	7
Indiana	3	5	7	4	5
Iowa	25	15	15	15	15
Michigan	3	6	7	5	6
Minnesota	18	15	15	15	15
Missouri	1	2	3	6	2
North Dakota	15	15	15	15	15
South Dakota	24	15	15	15	15
Wisconsin	5	8	11	7	8

[10] National Renewable Energy Laboratory, http://www.nrel.gov/gis/wind.html
[11] Energy Information Administration, http://www.eia.gov/forecasts/aeo/pdf/0383(2013).pdf

U.S. EPA's North Central grouping regard to geography and renewable energy potential can be classified as unusual at best. States such as Minnesota, North Dakota, and South Dakota have vast potential for wind energy development while mid-western states such as Indiana, Illinois and Michigan have limited potential for the same resource. To compare Indiana to the Dakotas would require the Dakotas to limit the value of their potential or make potentially unrealistic demands on Indiana. Unlike most of the other states in U.S. EPA's North Central grouping, Indiana's economy relies heavily on energy-intensive heavy industry which requires low energy costs and reliable power sources to survive. Examining the RPS standards for the states contained in U.S. EPA's North Central grouping does not provide a reasonable basis for logical comparison. Over 44% of the states contained in U.S. EPA's North Central grouping will have an RPS which expires in 2015 and one state has a megawatt goal rather than an RPS. The remaining 44% of the states have RPS targets which extend into 2025 (except Missouri, which expires in 2021). Also, those states which have RPS targets expiring in 2015 have target goals of 10%, while the states with RPS goals extending beyond 2020 have RPS goals between 15% and 25% (except Indiana which has set a voluntary goal of 10%).

State	RPS Goal (%)	RPS Goal (MW)	Target Date
Illinois	25		2025
Indiana	10		2025
Iowa		105	
Michigan	10	1,100	2015
Minnesota	25		2025
Missouri	15		2021
North Dakota	10		2015
South Dakota	10		2015
Wisconsin	10		2015

Should the EPA move forward with this rulemaking, to create a more equitable and appropriate evaluation of regional renewable potential and allow for the establishment of realistic regional goals, the EPA must re-evaluate the existing groups as they now stand and re-align them.

b. How will U.S. EPA account for long-term wind variability, such as that noted in the NREL Technical Report NREL/TP-5500-53637[12]? The level of wind generation varies with the amount of wind over the course of a year and the amount of wind across a region can vary from year to year. Will states be considered compliant if their actual renewable generation is within some percent (for example plus/minus 5%) of their state goal?

c. If U.S. EPA keeps building block 3, Indiana prefers the incorporation of an alternative RE calculation that relies on a state-by-state evaluation which considers each state's capacity for various types of RE measures. A state-by-state approach, rather than a calculation that focuses on regional goals which may overestimate RE capacity in some states, would ensure that RE targets are more tailored to each state's unique circumstances. However, Indiana insists that state RE goals must be both attainable and realistic, both from a capacity and cost-effectiveness standpoint. Indiana does not support the RE approach suggested in U.S. EPA's Alternative RE Approach TSD. The calculation used in the alternative RE approach measures technical potential by using the NREL database, which doesn't take into account important variables like cost or grid limitations. Further, this calculation includes a benchmark calculation based on the top third of states in a given type of renewable electricity. This is problematic because it may lead to unrealistic and unachievable RE goals. In Indiana's case, the alternative RE calculation sets a goal of 19% RE by 2025 and 2030, which is highly unlikely. The BSER calculation for Building Block 3 has a final goal of 7% RE by 2030. The final goal in the alternative RE approach is more than twice the RE number in the original calculation. Indiana does not believe this goal is at all realistic, especially since Indiana currently has no way to mandate RE measures. Further, due to the timing of the proposed rule and proposed date for state plan submittal, Indiana does not have the time to pursue legislative action in order to obtain proper authority to implement this Building Block. Indiana would prefer an alternative RE calculation that specifically focuses on each state's unique characteristics, rather than one that includes benchmarks or calculations based off of regional characteristics, to be incorporated into the state rate.

d. Indiana recommends that U.S. EPA include hydroelectric power in its baseline and future state goal calculations. Excluding hydropower does

[12] http://www.nrel.gov/docs/fy12osti/53637.pdf

not encourage utilities to continue to invest in the maintenance and upkeep of existing units. Also, it does not encourage states or utilities to invest in potential new hydropower capacity. Indiana has five hydropower plants that have the capacity for roughly 73.2 megawatts (MWs) of electric generation, according to the EIA[13], and these plants are currently not included in Indiana's state goal calculations. According to the National Hydropower Association, by 2025, the U.S. has the potential to install around 60,000 MW of new hydropower capacity[14]. Further, according to the EIA, Indiana produced around 34% more electric generation from hydropower in July 2014 than in July 2013, meaning there's an uptick in avoided CO_2 emissions that the state should get credit for in the goal calculation[15]. If U.S. EPA intends to encourage the use of renewable energy through this proposed rule, they need to promote the use of all types of renewable energy, not just certain ones. Indiana recognizes that U.S. EPA has not ruled out the option for states to include incremental hydropower generation from existing facilities or later-built facilities and encourages U.S. EPA to include hydropower generation in any revised goal calculations.

e. The proposed rule does not address the development, availability, and use of innovative state-of-the-art hydroelectric generation technologies within state plans. As an example, micro-hydroelectric generation technology has matured to the point where Portland, Oregon is installing in-pipe turbines capable of producing 1,100 megawatt hours of electricity a year – enough to power up to 150 homes. The proposed rule provides no incentive for the development of this environmentally safe, effective, and efficient technology which could be deployed within every municipality in the United States which operates a water utility. By creating this type of incentive, a deployment of this type of technology on a large scale would create significant economic initiatives, while upgrading water supply systems and providing incentives for academia and industry R&D efforts to develop even more efficient and effective micro-hydroelectric generation systems.

f. Indiana requests that U.S. EPA provide guidance as to what specifically would qualify as "permanent and enforceable," especially with regard to

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[13] Energy Information Administration, http://www.eia.gov/state/?sid=IN
[14] National Hydropower Association, http://www.hydro.org/tech-and-policy/faq/#723
[15] Energy Information Administration, http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_1_13_a

Building Blocks 3 and 4, which focus on the quantification of renewable energy and energy efficiency measures. Indiana does not have a mandated RPS in place but does have a non-binding goal[16]. The compliance timetable for plan development and implementation of this rule might not allow Indiana to pursue a RPS; therefore, the state may not have the mechanisms in place in order to properly enforce Building Blocks 3 and 4. More guidance with regard to what constitutes enforceability is crucial in order for Indiana to consider incorporating these building blocks into a state plan.

g. Indiana believes U.S. EPA should consider further promoting the incorporation of other types of renewable energy into Building Block 3, including hydropower, biomass, coal bed methane, and landfill methane. Digesters at confined feeding operations, as well as municipal waste treatment facilities, would produce energy by burning methane gas. Methane gas has a global warming potential over 20 times more potent than CO_2, according to U.S. EPA[17]. Therefore, if utilities are allowed to get credit for burning methane gas for energy, they not only gain the benefits of generating electricity, but the CO_2 equivalent produced is less than if they were to rely on coal for the same electricity being produced and the previously uncontrolled methane emissions are also eliminated. If the intent of this rule is to reduce greenhouse gas emissions then the use of methane to produce energy should not only be included, but it should also be incentivized with greater weight when calculated toward state goals compared to other fossil fuels and renewable energy.

h. Indiana would like clarification in any revised rule regarding waste to energy (WTE). Indiana interprets that each megawatt hour or steam equivalent generated by a WTE facility shall be measured as one megawatt hour of compliance toward the carbon intensity reduction requirements. Indiana law, along with Federal statutes and policies, recognize all of the energy generated from WTE as renewable. Indiana is not unique in this regard: every state which includes WTE in their renewable program similarly recognizes all of the energy these facilities generate as renewable. U.S. EPA should eliminate the ambiguity created in a technical document and specifically clarify that states desiring to

[16] DSIRE Indiana, http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=IN12R
[17] U.S. EPA, http://www.epa.gov/climatechange/ghgemissions/gases/ch4.html

recognize the energy generation from waste-to-energy be fully measured as compliance.

i. In order for Indiana to meet the renewable goal set by U.S. EPA in Building Block 3, the state would essentially have to double its wind farm capacity. However, current infrastructure does not allow all of the energy currently being produced by Indiana's wind farms to reach the grid, so additional wind energy capacity still would not increase Indiana's renewable energy share. Until new transmission capacity is in place, it is impossible for wind energy production to increase. Transmission lines are being scheduled for installation by the Midcontinent Independent System Operator (MISO) in the coming years to address the current problem[18], but the interim time frame for this rule does not give sufficient time for adequate infrastructure to be put in place. Based on the factors described above, Indiana is not in a position to adequately address the goal proposed by U.S. EPA for Building Block 3 within the proposed rule's timelines.

j. The RE goal for Indiana of 7,547,087 MWh (approximately 7% of total generation of 121,794,969 MWh) will be difficult to achieve. Indiana has a Voluntary Clean Energy Portfolio Standard (VCEPS) Program. None of the Indiana utilities have developed renewable generation using the VCEPS Program. Additional legislative action in Indiana will be required to achieve state compliance with the Clean Power Plan's RE goal, which could take a considerable amount of time to implement.

VI. Building Block 4: Energy Efficiency

a. Indiana is very concerned with the application of BSER under Building Block 4 of the proposed rule. In 2012, the year that U.S. EPA chose to garner data from, Indiana had a state-mandated energy efficiency program in place called Energizing Indiana[19]. However, the Indiana General Assembly passed legislation which brings the program to an end as of December 31, 2014, meaning Indiana will no longer have a state-mandated energy efficiency program. Because of this, Indiana no longer has any regulatory authority to mandate any type of demand-side energy

[18] Midcontinent Independent System Operator, https://www.misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/TransmissionExpansionPlanning.aspx

[19] Energizing Indiana, https://energizingindiana.com/

efficiency measures. Therefore, even though many utilities have decided to continue the program voluntarily, Indiana is uncertain how the state would receive credit in the state plan for reduced energy use for voluntary measures that the state has no control over. Even if the state legislature were to approve a new state-mandated energy efficiency program in the 2015 legislative session, Indiana would not have sufficient time to implement the program before state plan submissions would be due. Due to the proposed timeline and uncertainty of enforceability under Building Block 4, the state goal calculation may be unrealistic, and Indiana may not be able to rely on this building block at all in the state plan.

b. On pages 5-23 and 5-24 of the GHG Abatement Measures TSD U.S. EPA cites several studies [20] of achievable EE/DSM. But the U.S. EPA selected the most optimistic values rather than an average of the different analysis that would give appropriate effect to the credibility of all of the analysis. As U.S. EPA correctly noted, EE/DSM has been evolving; past experience may not prove to be an accurate predictor of future results. Thus, achieving a 1.5% annual increase in EE/DSM is suspect.

c. Independent analysis raise further questions as to the cost effectiveness of energy efficiency in the region. Preliminary MISO regional modeling results show that the model did not choose energy efficiency (even assuming U.S. EPA's EE costs which are lower than Indiana's actual EE costs) when the model was allowed to optimize CO_2 reduction options at

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[20] On a normalized basis, the EPRI 2009 study provides an achievable annualized potential range of <u>0.2-0.4% per year</u> (realistically achievable and maximum achievable potential, respectively) through 2030 at the national level. Two more recent studies also provide national estimates of achievable EE potential: EPRI (2014) updates their 2009 analysis, using a conventional bottom-up engineering approach, and ACEEE (2014), using a top-down, policy-based approach derived from state experience and their evaluated results. EPRI (2014) results show an average <u>annual achievable potential range of 0.5% to 0.6% per year</u> (achievable and high achievable potential, respectively). <u>ACEEE found average annual achievable potential of 1.5% per year.</u>

At the regional and state level, two meta-analyses, Sreedharan (2013) and Eldridge et al. (2008), captured numerous studies conducted between 2001 and 2009. The meta-analysis conducted by Sreedharan (2013) presents average annual values of 4.1% per year in technical potential, 2.7% per year in economic potential, <u>and 1.2% per year in maximum achievable potential</u>. In comparison, Eldridge et al. (2008) estimated average annual values of 2.3% per year in technical potential, 1.8% per year in economic potential, and <u>1.5% per year in achievable potential</u>. To supplement these studies with more recent data, the EPA has conducted a meta-analysis of twelve studies conducted between 2010 and 2014 at the utility, state or regional level (see Appendix 5-1). The EPA review indicates an average annual achievable potential of 1.5% per year across the reviewed studies. See Appendix 5-2 (Summary of Recent (2010-2014) – Emphasis added.

the least cost. Energy efficiency is a large part of U.S. EPA's assumed building blocks for Indiana. However, energy efficiency does not appear to be part of the least cost solution to meet CO_2 goals for Indiana.[21]

d. U.S. EPA requested comment on a potential increase in annual incremental savings from 1.5% to 2% per year, as well as a pace of improvement from 0.2% to 0.25% per year. Indiana does not support increases to either of these two categories. Indiana questions the practicality and cost effectiveness of these increases as costs rise sharply as more EE measures are put into place. Further, as mentioned above, Indiana currently does not have the regulatory authority to require any type of energy efficiency program and the timing of this rule makes it impossible to get such authority in place by the proposed date of plan submittal. Indiana is uncertain as to how to include this building block in its state plan in the first place and therefore would not support an increase in the annual incremental savings percentage or pace of improvement calculation.

e. With regard to calculating EE for Building Block 4, Indiana requests that U.S. EPA provide a more detailed explanation of its calculations. Some states calculate energy efficiencies differently than others and in order for each state to get equal credit for various energy efficiency measures; a standard methodology needs to be set by U.S. EPA. For instance, the same LED light bulb replacement is credited differently under Michigan's RPS than under Indiana's renewable portfolio goal. U.S. EPA should release a standard for calculating various energy efficiencies prior to the implementation of the rule in order to ensure that each measure is calculated in a fair and consistent manner. Indiana also requests that U.S. EPA provide detailed spreadsheets that contain formulas, rather than hard numbers, in order for states to have the opportunity to understand just how the EE calculations would work going forward, particularly for the calculations used in Building Blocks 3 and 4.

f. Indiana also requests examples of what would qualify as evaluation, measurement, and verification (EM&V) under both Building Blocks 3 and 4. Since Indiana will no longer have a state-mandated energy efficiency

[21] MISO GHG Regulation Impact Analysis – Initial Study Results September 17, 2014 (https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/PAC/2014/20140917/20140917%20PAC%20Item%2002%20GHG%20Regulation%20Impact%20Analysis%20-%20Study%20Results.pdf)

program at the close of 2014, nor does the state have an RPS currently in place, Indiana is unsure what would constitute suitable EM&V if these building blocks are incorporated into the state plan. Due to the proposed timeline of the rule, Indiana would not be able to get legislative authority in place to be able to implement or enforce renewable energy or energy efficiency programs before the state plan is due, so it is unclear how Indiana would be able to rely on either Building Blocks 3 or 4 in the state plan.

g. U.S. EPA's energy efficiency cost estimates of $0.09/KWh are much lower than Indiana's derived cost estimates. An independent study done by National Economic Research Associates (NERA) suggests that, based on a review of historical energy efficiency costs, a national levelized cost of $0.10/KWh is a more accurate assumption[22]. Indiana's costs are even higher. Based on the Indiana utilities' 2015 DSM/EE plans, the costs to utilities range from $0.11 to $0.16/KWh. However, the Indiana Office of Utility Consumer Counselor (OUCC) points out that costs to ratepayers are even higher, as Indiana's inclusion of lost margins and shareholder incentives more than doubled Indiana's DSM/EE costs to an average of $0.32/KWh. If these compliance costs are taken into account into 111(d), this could have an impact on the BSER analysis for this building block, as well as make this option less affordable for states to implement and, in turn, for consumers, who would bear the brunt of such an increase through an increase in utility rates. Indiana recommends that U.S. EPA consider all available costing information in order to provide stakeholders with more reliable cost estimates.

h. Indiana seeks clarification of how states that undertake investments between 2012-2020 will be assured they will be fairly credited. For 2012-2017, is U.S. EPA only referring to the lifetime of the measures being reflected in the cumulative savings figures or is there something more? As stated previously, Indiana believes most of the "low-hanging fruit" will be captured in the earlier years and achievement in subsequent years will be more difficult and expensive, barring unforeseen changes in technology or other factors that affect cost-effectiveness. Please detail how these pre-2020 improvements in EE savings will benefit a state in meeting its EE goals in 2020 and beyond. One reasonable interpretation of the proposed

[22] National Economic Research Associates,
http://www.nera.com/content/dam/nera/publications/2014/NERA_ACCCE_CPP_Report_Final_1014.pdf

rule would suggest that states might be better off postponing aggressive EE/DSM until 2020 to get maximum value. We doubt this was U.S EPA's intent, but clarification is needed.

i. U.S. EPA acknowledges demand response, or peak shaving, within the proposed rule as an element of some states' energy efficiency resource standards (EERS), but also characterizes Building Block 4 as largely 'end-use' energy efficiency. Indiana believes that credit for reductions under Building Block 4 should be given for measures such as demand response, which reduces or shifts electricity usage during peak periods and is typically utilized by electric system operators in order to produce energy at a more efficient rate. This not only saves consumers money, but it also results in overall reduction of CO_2 emissions. FERC 2009 National Assessment of Demand Response Potential developed four potential scenarios to reflect various levels of demand response within the nation over a ten year period from 2009 to 2019[23]. They found that demand response has the potential to reduce peak electricity demand by as much as 20% by 2019 if fully utilized under the Full Participation scenario. Even under the Expanded Business-As-Usual scenario, which expands current demand response programs to all states, utilizes a partial deployment of advanced metering infrastructure, and ensures that a small percentage of ratepayers would make use of dynamic pricing, peak electricity demand is reduced by 9% over the ten year period (2009-2019). If demand response programs are largely expanded and encouraged across the country, a large amount of peak electricity demand could be saved, resulting in a large amount of avoided CO_2 emissions. U.S. EPA should encourage the use of demand response by incorporating it in the energy efficiency calculations of Building Block 4 since it has the potential to cut CO_2 emissions, in addition to saving money for ratepayers.

j. A state should receive the full credit for demand-side energy efficiency programs, regardless if it is a net importer of electricity. A reduction in generation is a reduction in generation, whether or not the generation occurs within a state's borders. To make such adjustments for states that are already having in-state supply issues would only discourage DSM adoption and serve as further disincentive to the importing states that need to implement DSM/EE programs the most. Moreover, if energy efficiency costs are paid for by "out of state" ratepayers, the 111(d)

[23] Federal Energy Regulatory Commission, http://www.ferc.gov/legal/staff-reports/06-09-demand-response.pdf

benefits of energy efficiency should be credited to the state that is paying for the efficiency improvements.

k. Indiana believes that U.S. EPA should consider allowing states to include other types of energy efficiency measures within their state plans. For instance, Indiana has taken steps to reduce the amount of energy used by water and wastewater utilities. Energy consumption by public drinking water and wastewater utilities, which are primarily owned and operated by local governments, can represent 30-40% of a municipality's energy bill. At drinking water plants, the largest energy use (about 80%) is to operate motors for pumping. At wastewater treatment plants, aeration, pumping, and solids processing account for most of the electricity that is used.[24]" The Indiana Finance Authority, in cooperation with IDEM, has promoted the use and installation of energy efficient pumps, pipes, treatment systems, and control processes as part of the state's Revolving Loan Program for financing water and wastewater infrastructure projects. Some examples of these projects include the installation of energy efficient variable frequency drive pumps at Fort Wayne and Jeffersonville, wastewater collection improvements to reduce the amount of water needing treatment in Logansport and New Albany, and water main replacement to prevent leakage in Owensville and Brooklyn. There have been over 25 projects improving energy efficiency since 2012. A rule requiring water utilities to address unacceptable leakage from their drinking water infrastructure was promulgated to improve efficiency and save energy by reducing the amount of water pumped and treated. Indiana plans to continue to take positive steps to improve the efficiency of utilities in the state not only because of the reduction in energy used, but also because it improves the affordability of the services to consumers. Energy savings made by water and wastewater utilities in the state should receive credit for reducing CO_2 emissions, and Indiana should be allowed to include these savings in its state plan.

l. As technology advances and the cost of resource alternatives change, Indiana hopes that the definition of DSM/EE would also be appropriately expansive. This seems to have been recognized by U.S. EPA, but Indiana needs specific guidance demonstrating that U.S. EPA will be

[24] *Congressional Research Service,* Energy-Water Nexus: The Water Sector's Energy Use, Claudia Copeland, January 3, 2014

receptive to additional energy efficiency and demand reduction programs.[25]

VII. Legal issues

a. As stated in the cover letter, there are several issues with U.S. EPA's purported authority to regulate GHGs in the manner specified by the proposed rule. Regulations promulgated under 111(d) require that the agency first adopt standards under 111(b). The proposed predicate rules under 111(b) have not yet been finalized and may be invalidated upon judicial review. Therefore, U.S. EPA's attempt to regulate GHGs from existing EGUs is premature.

b. The CAA does not grant U.S. EPA authority to regulate source categories under 111 when the sources are already subject to regulation under section 112.

c. 111(d) does not permit outside the fence regulation of affected sources. If a state like Indiana is unable to develop a plan within the time frame prescribed, or should the state opt for a federal plan, U.S. EPA must have the authority to institute such a plan. U.S. EPA cannot impose requirements on states that the agency itself does not have the authority to enforce. In this case, U.S. EPA has inadequate authority to institute a plan based on how the agency applied BSER in determining the goal.

VIII. Miscellaneous

a. The use of a single year for baseline establishment verses a multiyear baseline is inconsistent with common U.S. EPA practice. Whenever variability in meteorology or energy markets is involved, U.S. EPA tends to rely on a multi-year average base year. The demand for electricity varies based on meteorological swings (extreme cold or extreme hot). Additionally, the dispatch and utilization of coal and natural gas can vary based on outages and fuel prices. Therefore, the use of multiple years

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[25] A utility pursuing aggressive EE/RE programs may avoid the construction of new fossil generating capacity and expansion of transmission and distribution capability, and may even allow the utility to retire non-economic generating units no longer required for generation or reliability purposes. State Plan Considerations -Technical Support Document (TSD), page 32.

would be a more appropriate method to normalize the data in characterizing a base year. 2012 was an unusual operating year for many Indiana coal-fired generating units. Some units, such as NIPSCO's R.M. Schahfer Generating Facility's Units 14 and 15, were involved in major construction projects to install FGD units to comply with the Mercury and Air Toxics Standards (MATS) and the Cross State Air Pollution Rule (CSAPR), so they did not operate at the capacity factors normally seen for those units.[26] Also, many base load coal-fired units did not operate at their highest capacity during 2012 because of low natural gas prices.[27] Indiana recommends that U.S. EPA use a 3-year average baseline for emissions, generation, and capacity factors, as opposed to relying on only 2012 data.

b. Based on a review of U.S. EPA's technical support documents included as a part of the proposed rule, Indiana has identified several data points that are inaccurate specific to a number of active coal-fired facilities currently located in the state. This includes the classification of some of the state's facilities as "peakers". Details regarding this matter are included in Attachment B. There are additional concerns associated with the 2012 emissions data. For example, Duke Energy's Edwardsport Generating Station is a new coal gasification facility sited adjacent to the old Edwardsport power plant that had coal fired boilers. The old plant ceased operation prior to 2012 and the new Edwardsport IGCC plant was in the initial start of operations in 2012. The emissions data U.S. EPA used in the TSD for Edwardsport is in no way reflective of actual operating conditions and should be adjusted when evaluating Indiana's state goal. This facility ran very little during 2012, yet U.S. EPA data assumes this facility was operating at full capacity. The Edwardsport IGCC facility was conducting tests for operation and was not yet fully in service in 2012.[28] Furthermore, the Edwardsport IGCC used natural gas instead of coal for a significant portion of the time it was operational in 2012.[29] The future emission rate for this facility will likely be greater than the 2012 levels because this facility is designed to run primarily on synthesized gas from

[26] IURC, Final Order, Cause No. 44012, Phase I (December 28, 2011).
[27] Energy Information Administration. (October 19, 2012). **Today in Energy.** *Electricity from coal and natural gas both increased with summer heat*. http://www.eia.gov/todayinenergy/detail.cfm?id=8450 *See also,* Tierney, S. (July 30, 2012). **Power Magazine.** *Why Coal Plants Retire: Power Market Fundamentals of 2012.* http://www.powermag.com/why-coal-plants-retire-power-market-fundamentals-as-of-2012/.
[28] IURC, Cause Nos. 43114 IGCC 9-11, Direct Testimony of Petitioner's Witness Jack Stultz.
[29] *Id.*

coal. Indiana is concerned that the current emission rate targets for Indiana under the Clean Power Plan could prevent the Edwardsport IGCC plant from fully operating according to its original design. If this happens, Indiana ratepayers will bear more than $2.5 billion in construction costs for this facility[30] without receiving the full benefits expected when the initial investment in the plant was originally approved in 2007.[31] Under Indiana law and past orders from the IURC, the utility may recover approved construction costs even if the facility never operates to serve ratepayers.[32] Preventing the Edwardsport IGCC plant from fully operating could represent a significant stranded cost issue for Indiana ratepayers, which is explicitly contrary to the intent of the rule.

c. Indiana is recommending that U.S. EPA use the 2013 EIA growth forecast for goal estimation as opposed to 2010. There is a ten-fold difference between the two. As such, the most current growth forecast should be used, as this could have a substantial effect on future year goal development.

d. Indiana urges U.S. EPA to reconsider and clarify when improvements at an EGU do or do not trigger NSR requirements. U.S. EPA should consider waivers or exemptions for facilities seeking to make substantial improvements to incentivize the reduction of CO_2 emissions if that is U.S. EPA's main objective in this rulemaking.

e. U.S. EPA should consider how to equally evaluate all electric service providers including investor owned utilities, municipal utilities, and rural electric membership cooperatives that supply power to the grid. These types of utilities are unique and may require special considerations, particularly rural cooperatives and smaller municipal utilities. These types of facilities generally service a lower number of members per line than larger utilities. Most of those serviced are rural customers that are in the lower income bracket. These utilities also service far fewer industrial customers than other utilities. As a result, the ability to implement Building Block 4 for these utilities is far more difficult and costly than for other utilities. Given the demographic make-up of the customers for these utilities, increases in rates will be felt much more deeply than for other utility customers since they not only have less income to pay for higher

[30] IURC, Final Order, Cause No. 43114 IGCC 4S1 (December 27, 2012): p. 92.
[31] IURC, Final Order, Cause No. 43114 (November 20, 2007).
[32] Indiana Code §8-1-8.5 through 8.7.

rates, but also less means to invest in energy efficiency measures. The economy of scale dictates that the costs for energy efficiencies for these areas will be much higher without the industrial component factored in.

f. U.S. EPA is seeking comment concerning states receiving CO_2 credit for having sustainable forestry initiatives. Indiana disagrees that CAA Section 111 allows consideration of outside-the-fence control measures as part of a BSER analysis. However, if the final rule includes outside-the-fence measures, the credits available to states for GHG reductions should be expanded to include CO_2 sequestration through planting, maintenance, and management of state forests. Analyses on CO_2 sequestration through Afforestation and Improved Forest Management (two types of offset methodology) in Indiana indicate this would be an achievable emission-reduction strategy. Afforestation of 1.2 million non-prime, agricultural crop acres could yield 113 MMt CO_2e by 2020. An additional 4.8 million acres of non-federal timberland in Indiana could be tapped for improved CO_2 storage projects to further avoid 38.4 MMt CO_2e by 2020.

g. U.S. EPA is requesting comment on co-firing as a compliance option. In some cases, it may be advantageous from both an emissions and a cost perspective standpoint. In other instances, it may result in stranded costs for pollution control equipment that is already installed, which would result in higher electric rates for Indiana. With a large number of coal-fired facilities in the state, this could have a significant impact on Indiana's future. Indiana is not opposed to this; however, it may not be economically viable for some co-firing options. Biomass co-firing would involve transportation of biomass to the facility. It may be cost prohibitive for facilities to bring in biomass from farther away but that may be required to keep a unit co-firing with biomass all year long. Indiana is not opposed to co-firing as an available compliance option, but Indiana is strongly opposed to this being a mandated requirement for EGUs.

h. Indiana strongly believes that carbon capture and sequestration (CCS) should not be considered a technically viable option for facilities to install at this point. The technology is not commercially available, is still in the testing phase, uses large amounts of energy to operate, and to this point has not proven to be a cost effective way of reducing CO_2 emissions. Also, CCS retrofit technologies require space around the boiler to be installed. Many of Indiana's existing coal powered facilities currently lack sufficient space to install CCS.