**Proposed Existing Source Performance Standards for Greenhouse Gas Emissions from Electrical Generating Units**
**EPA-HQ-OAR-2013-0602**

**Comments of LG&E and KU Energy LLC**

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LG&E and KU Energy LLC (hereinafter "LKE"), a subsidiary of PPL Corporation, submits the following comments in response to the U.S. Environmental Protection Agency's proposed rule entitled "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units" and EPA's Supplemental Notice of Data Availability. LKE is the parent of Louisville Gas and Electric Company (LG&E) and Kentucky Utilities Company (KU), public utilities owning and operating approximately 8,000 megawatts of coal-fired generation in Kentucky that in 2013 provided 94% of the electricity needs of their 941,000 electricity customers. LKE has a significant interest in participating in the above-rulemaking to ensure that EPA's efforts to regulate carbon dioxide (CO2) and other Greenhouse Gases (GHG) are legally permissible and support President Obama's "All-of-the-Above" energy strategy. Unfortunately, in the proposed emission guidelines, as drafted, and under the approaches referenced in the Notice of Data Availability (NODA), EPA has exceeded its statutory authority. Setting aside the legal infirmities, EPA has proposed rules that undermine the President's "All-of-the-Above" energy strategy which consists of three goals: (1) Supporting economic growth and job creation; (2) enhancing energy security; and (3) deploying low-carbon energy technologies and laying the foundation for a clean energy future. The reduction target assigned to Kentucky in EPA's proposed emission guidelines will pose a significant challenge for the state. Under the regionalized approach referenced in the NODA, Kentucky's target may prove virtually unachievable under the constraints faced by the state, with potentially devastating impacts on Kentucky's economy.

## I. Introduction

Coal-fired generation currently provides over 90% of the electricity needs of Kentucky and has long been the preferred source of low cost, reliable power in the state. Kentucky has found coal-fired electricity to be a competitive advantage in attracting and maintaining energy-intensive industries and the jobs that they bring. In recent years, Kentucky's coal-fired utilities have undertaken unprecedented construction projects to install extensive environmental controls to meet the requirements of new EPA rules including the Mercury and Air Toxics Standards, Cross State Air Pollution Rule, and revised National Ambient Air Quality Standards. From 2009 to 2015, LG&E and KU have spent or will spend over $3 billion on such environmental control projects, not counting the cost of constructing replacement generation for the six coal units it is retiring. While compliance with these new EPA rules has posed significant challenges and resulted in substantial expense for LKE's customers, coal-fired power generation has remained, to date, an economical and reliable source of electric power in Kentucky and elsewhere in the nation.

In developing its proposed emission guidelines in the present rulemaking, EPA seeks to fundamentally re-fashion the power generation mix of states such as Kentucky. Rather than adopt a facility-specific performance standard for coal-fired power plants as required by the statute, EPA proposes state-wide reduction targets set (in the case of Kentucky) at a stringent average emissions rate of 1,763 lbs. CO2/ net MWH compared to the state's 2,166 lbs. CO2/ net MWH average in 2012. If promulgated, the proposed reduction targets effectively create a partial ban on coal-fired generation and promote other alternatives, specifically natural gas, renewables, and energy efficiency. While all of those alternatives have a legitimate role to play in meeting the nation's energy needs and should play an important role in the President's "All-of-the-Above" strategy, there is nothing in Section 111(d) that confers any authority on EPA to partially ban the use of coal-fired generation.

Paradoxically for a rule governing existing coal-fired generation, three of the four "building blocks" used to identify state-specific reduction targets consist of reductions projected from non-coal generation options or other reduction measures. We later address the issue of whether EPA may properly consider such "outside the fence" reductions in developing emission guidelines for coal-fired power plants under Section 111(d). Setting that issue aside for now, these particular building blocks provide scant basis for setting realistic emission reduction targets for Kentucky.

We urge EPA to consider the following:

(1) Building Block 2 encompasses reductions in the use of coal-fired generation through increased utilization of existing natural gas combined cycle (NGCC) units, regardless of the price of natural gas, while Kentucky currently has no operating NGCC units and only one such unit is currently under construction.

(2) Building Block 3 encompasses increased use of zero-emitting sources of electricity such as renewables energy or certain nuclear energy facilities. EPA has acknowledged Kentucky's low potential for renewables by projecting that it would represent only 2% of Kentucky's generation in 2030 (note that renewable energy, not considering hydro, currently comprises essentially zero % of current Kentucky generation); existing Kentucky law essentially bans nuclear power plants from the state.

(3) Building Block 4 encompasses reductions achieved through end-use energy efficiency measures which have not been demonstrated in Kentucky anywhere close to the scale contemplated by EPA. In fact, a study commissioned by the company and submitted to the Kentucky Public Service Commission indicates that LG&E's and KU's potential for implementation of energy efficiency measures is less than 25% of the level assumed by EPA.

(4) Even Building Block 1 – heat rate improvements at existing coal-fired power plants – is largely unrepresentative of feasible future reductions from generating units in the LG&E and KU fleet. As described in more detail herein, EPA's projection of future heat rate improvements is either over-stated or encompasses measures which have already been undertaken. Additionally, the implications from re-dispatching resources from Building Blocks 3 and 4 will negatively impact fossil unit heat rates.

EPA's reliance upon these flawed factors exceeds its statutory authority and heavily stacks the deck against continued operation of coal-fired power generation that is critical to meet the energy needs of Kentucky.

Another serious flaw from the proposed regulations is the application of the interim goal and the subsequent glide path from 2020 to 2030. The requirements proposed with the interim goal places many states, including Kentucky, in a position where most potential compliance measures must be implemented in 2020. This "cliff" should be eliminated and the states should develop compliance plans for reaching a 2030 goal based on their specific circumstances. Based on the regulatory timelines for finalizing the regulations and gaining approval of state compliance plans, it is not possible to modify the infrastructure or build new facilities to meet a 2020 start date.

While EPA's proposed state-specific reduction targets for Kentucky and other states create compliance challenges for coal-fired generation, some of the options being considered by EPA, as indicated in the NODA, would essentially remove coal-fired generation as an important part of the nation's generation mix. "Levelizing" emission reduction targets through a regional approach could substantially increase the hardship on coal-reliant states such as Kentucky which is surrounded by states with greater potential for renewables, available nuclear capacity, or higher reliance on natural gas. It would be inconsistent and irrational for EPA to evaluate state-specific reduction targets deemed achievable by EPA and then proceed to mandate some states go beyond their assigned targets and allow others to meet targets significantly below their calculated potential.

In short, most of the NODA alternatives to which EPA seeks comment would result in reduction targets that are largely unachievable by Kentucky without significant and concerning implications for the State and electricity customers of LG&E and KU. These are briefly discussed below.

The Kentucky Energy and Environment Cabinet has determined that under some "levelization" scenarios presented with the alternatives in the NODA, Kentucky's reduction target could be adjusted as low as 1,034 lbs. $CO_2$/ net MWH. Reductions of such a magnitude would force utilities to prematurely close most of their coal-fired plants in Kentucky. For every coal-fired generating unit remaining in service, a utility would be forced to develop an equivalent amount of renewable energy, a daunting prospect in a state like Kentucky with few opportunities to generate energy from renewable sources. The vast majority of generating capacity in Kentucky would either move from coal to natural gas-fired generation or come from renewable resources imported from other states.

Second, the potential for widespread changes in electricity supply resources raises significant concerns regarding the adequacy of existing transmission systems. Reliability of the electric grid is of critical importance in the development of and the subsequent implementation of any plans required for compliance with final emission guidelines. A reliable power system includes more than generation resources adequate to meet electric demand. The transmission grid has been built and operated over time not just to balance supply with demand, but also to preserve voltage and frequency criteria for the state-wide transmission grid as well as contingencies that might disrupt its operation. The provisions of the proposed emission guidelines and the alternatives identified in the NODA do not take into account the full implications and possible impacts on the operation of the electric grid.

The North American Electric Reliability Corporation (NERC) has primary responsibility for assuring reliability of the nation's electric transmission system. NERC's initial report, entitled *Potential Reliability Impacts of EPA's Proposed Clean Power Plan,* released in November 2014, identifies a number of factors from the proposed building block analyses that require consideration of grid reliability impacts. In particular, NERC expressed concerns that:

> *The proposed timeline does not provide enough time to develop sufficient resources to ensure continued reliable operation of the electric grid by 2020. To attempt to do so would increase the use of controlled load shedding and potential for wide-scale, uncontrolled outages.*

To avoid foreseeable, but unintended consequences, it is imperative that EPA closely coordinate with NERC to gain a better understanding of the negative impacts the proposed guidelines will have on the reliability of the nation's transmission system. In addition, more reliability risks are created by EPA's false presumption that adequate pipeline capacity exists to serve increased gas utilization and new natural gas-fired generation. It is also not practical to presume additional gas pipelines can be sited and constructed without significant cost and extended periods of time.

Such a sea change in generation mix – and the corresponding impact on electricity prices – would have serious implications for the economies of low cost electricity states such as Kentucky. The proposed guidelines would turn electric service into a "luxury service" that will harm our low income customers, especially our seniors, and undermine our incomplete recovery from the Great Recession by placing a significant economic burden on our small to midsize business community. Upwards of 90% of businesses in Kentucky have less than 50 employees.

Third, the Kentucky Energy and Environment Cabinet has projected that a 10 percent increase in Kentucky electricity prices could result in a $2 billion decrease in state GDP and significant job loss in the mining and energy-sensitive manufacturing sectors. See Kentucky Energy and Environment Cabinet, *Comments on Proposed Section 111(d) Rule For Greenhouse Gas Regulations*, November 26, 2014. EPA's reduction target for Kentucky in the proposed guidelines would pose a serious challenge for the state. "Levelization" of the original target to increase its stringency would disregard EPA's prior assessment of reasonably available reductions and saddle the state's residents and businesses with a tremendous economic burden.

Finally, EPA projects an additional 49 GW of coal plants will retire under the proposed emission guidelines on top of the retirements already announced from previous EPA regulations. This transition to a different energy supply portfolio in such a short period of time is very concerning. The regional approaches proposed with the NODA will create an even greater energy transition raising the specter of significant stranded costs arising from recent installation of environmental controls on coal-fired plants forced to retire under the emission guidelines.

LKE respectfully urges EPA to reconsider the scope of its authority under Section 111(d) and carefully assess the full implications of the proposed guidelines for states such as Kentucky that rely on coal-fired generation equipped with the latest pollution control technology.

## II. EPA's Proposed Emission Guidelines Exceed its Statutory Authority

In the interest of avoiding undue duplication, LKE points EPA to the objections to the proposed guidelines set out in detail in comments submitted by the Utility Air Regulatory Group and the Coalition for Innovative Climate Solutions. However, LKE describes its basic objections to the proposed guidelines as follows.

### A. BSER May Not Reflect Projected Reductions from Non-Jurisdictional Sources.

Section 111 authorizes EPA and the states to promulgate standards of performance for new and existing sources within certain designated source categories. Under the statute, once EPA lists a source category, such as coal-fired electric generating units, and promulgates a new source performance standard under Section 111(b), EPA may require states to develop plans adopting standards of performance for existing sources in that source category under Section 111(d). 40 CFR 60.20-60.29 provides for EPA to issue emission guidelines to provide a framework for the development and submittal of these state plans. Section 111(a) defines "standard of performance" as "a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction … the Administrator determines has been adequately demonstrated." On its face, Section 111 provides for standards that regulate the emissions performance of individual power plants. What this means is that Section 111(d) authorizes EPA to require utilities to meet a lower emission standard made possible by the use of new or improved commercially available technology. As the industry develops new or improved operating procedures that reduce pollution at coal-fired power plants, Section 111(d) authorizes EPA to require electric utilities to adopt these procedures.

Neither the plain language of the statute nor EPA's long established interpretation of its authority support EPA's new interpretation that the word "system" is sufficient to allow the agency to base a standard of performance on any "set of things" that leads to reduced emissions from a particular power plant. It is well beyond the limits of EPA's statutory authority to propose standards of performance for coal-fired electric generating units based on reductions EPA believes are achievable through deployment of "outside the fence" alternatives to replace coal-fired generation consisting of natural gas, renewable energy, and energy efficiency. Consequently, EPA has exceeded its statutory authority in using "Building Blocks 2, 3, and 4 in setting reduction targets for existing electric generating units.

### B. EPA May Not Force Reduced Utilization of a Source Through Application of BSER.

Section 111 provides no authority for EPA to establish a standard of performance based on reduced utilization of a source. In other words, EPA lacks statutory authority to ban or limit the use of coal-fired generation. Section 111(a)(1) provides that a "standard of performance" must be a "standard for emissions of air pollutants which reflects the degree of <u>emission limitation</u> achievable through the application of [BSER]" (emphasis added). EPA is authorized to issue rules that require utilities to use available technology to reduce "emissions of air pollutants." In Section 111(b)(5), Congress expressly prohibited EPA from requiring "any particular technological system of continuous emission reduction to comply with any [NSPS]. Considering that Congress found it objectionable for EPA to compel installation of any particular control technology, there is certainly nothing in the statutory language suggesting that EPA has the authority to impose an even more drastic requirement in the nature of directing reduced operation of the regulated source. EPA has never previously proposed reduced utilization of a source as BSER under Section 111.

### C. EPA May Not Regulate Sources Under Section 111 Which Are Already Subject to Regulation Under Section 112.

In proposing the emissions guidelines, EPA has ignored the express provisions of Section 111(d) which prohibit the agency from adopting emission guidelines for existing sources from a source category already subject to hazardous air pollution regulations promulgated pursuant to Section 112. EPA listed coal and oil-fired electric generating units as a source category in 2000 and issued a rule under its Section 112 authority in 2012 (the Mercury and Air Toxics Standards). Contending that it is reconciling ambiguous provisions of the statute, EPA focuses on alleged authority under a technical amendment of the statute which the agency previously agreed was superseded by another 1990 amendment to Clean Air Act. As a practical matter, it makes little sense for sources subject to the stringent Maximum Achievable Control Technology (MACT) standards under Section 112 to also be subject to Section 111 standards reflecting the Best System of Emission Reduction (BSER). In *American Electric Power, Inc. v. Connecticut*, 131 S.Ct. 2527, 2537 n. 7 (2011), the Supreme Court has unequivocally stated that "EPA may not employ [Section 111(d)] if existing stationary sources of the pollutant in question are regulated under … the 'hazardous air pollutants' program [of Section 112]."

### D. EPA May Not Dictate a State's Implementation Options or Mandate Measures Beyond the Scope of the Clean Air Act.

EPA cannot indirectly force the states to adopt emission reduction measures that EPA itself lacks the authority to require under the Clean Air Act. EPA engages in the fiction that it has merely considered available "outside the fence" measures such as renewables and energy efficiency in setting state-specific targets while leaving the states with the flexibility to adopt whatever measures they please to achieve the targets. In reality, the stringency of EPA's proposed targets will force states to adopt compliance measures such as Renewable Portfolio Standards that are clearly beyond the scope of EPA's authority under Section 111. Under Section 111(d), EPA's authority is limited to "establish[ing] a procedure … under which each state shall submit to the Administrator a plan which (A) establishes standards of performance … and (B) provides for the implementation and enforcement of such standards." Through the use of stringent targets, the proposed rule constrains implementation options that would otherwise be available to the states and dictates the specifics of the state program.

## III. BSER Assumptions and Calculations

### A. EPA Has Improperly Determined BSER.

EPA proposes to define the "Best System of Emissions Reduction" (BSER) as the combination of four components, or "Building Blocks." These are (1) heat rate improvements at existing coal-based electric generating units (EGUs); (2) increased utilization of existing natural gas combined cycle (NGCC) units; (3) increased deployment of renewable generation and certain "at risk" nuclear units; and (4) increased end-use energy efficiency. It appears that EPA made numerous assumptions in the proposed guidelines about the emission reductions achievable by each separate Building Block that are unsupported by evidence in the record.

While it is EPA's role to determine BSER in compliance with the provisions of the CAA, ultimately it is the role of the states to determine the application of the BSER to specific affected units within that state.

EPA has a statutory obligation to ensure that BSER is adequately demonstrated and to show that the state emission rate goals are achievable, particularly in light of the interconnected nature of the power system.

EPA's assumptions and conclusions about the individual Building Blocks that EPA identified in setting BSER should be scrutinized in light of the best available data and experience and, adjusted as necessary. EPA should ensure that the state emission rate goals in the final rule reflect an evaluation of all BSER components together in order to properly reflect the interconnected nature of the power sector and appropriate assumptions and conclusions about the level of reductions achievable by each component.

<u>Severability</u> - If EPA or a reviewing court eliminates one or more of the building blocks which provide the foundation for the proposed reduction targets, EPA must revise the rule to eliminate the reductions associated with that building block and adjust the state-specific performance goals accordingly. Eliminating a building block without adjusting the emissions reduction targets would result in a final rule that does not strictly reflect BSER as defined by EPA in the proposed rule and performance goals that may be unachievable from a practical standpoint. Because the proposed rule "pushes the envelope" by encompassing outside the fence line measures that have not previously been considered in determining BSER, there is a significant risk of one or more of the building blocks being invalidated by the courts (if not eliminated by EPA itself). In order to reduce the resulting uncertainty that could delay implementation of the program by the states and seriously impede compliance measures by regulated sources, EPA should provide a clear description of how it will adjust the state-specific performance goals in the event that a building block is removed.

<u>BSER Cannot Include Co-Firing Natural Gas</u> - The determination of BSER must consider options that are available at the source (inside-the-fence) for the particular source and fuel category. A change in source technology that would dictate a change to a different fuel type or co-firing with a different fuel than included in a unit's original design (e.g. natural gas, biomass) was not intended by the CAA to be a component of BSER. Infrastructure issues for providing sufficient gas supply to existing units are commonly present so that co-firing is not always a readily available application. When considering natural gas as a co-fired fuel, the following issues must be taken into account:

1. Proximity of a major gas pipeline;
2. Capacity of the source pipeline;
3. Long-term natural gas supply availability;

4. Potential for interruptible natural gas supply; and
5. Cost of providing adequate gas supply infrastructure.

There will be some coal-fired units that can reasonably and economically address the five considerations listed above. However, application of the technology for many coal fired units will be prohibitive from the standpoint of logistics, economics, and unreliability of emission reduction measures. Although co-firing may be an option for states to consider as a component of compliance planning, these infrastructure issues will be a deterrent that prohibits co-firing natural gas as a component of BSER for many EGUs.

In the NODA, EPA suggests that co-firing of natural gas might be appropriate for goal setting and compliance. While LKE agrees that co-firing gas might be available as a compliance options for some EGUs in a state's compliance plan, we do not agree that it should be included in the calculation of the state goal. Co-firing technology in many cases will result in increasing CO emissions per MW which may trigger PSD review. Because the potential applications of co-firing are limited by EPA's current NSR guidance, co-firing is not an "available" control technology as a BSER component. Likewise, application of co-firing in the state compliance plan may be limited for many units as changes in the calculation of projected actual emission may occur with changes in utilization created by increased operation of the co-fired unit.

<u>BSER Cannot Include Application of Partial Carbon Collection and Storage (CCS)</u> - LKE agrees with EPA's contention within the discussion of identification of Best System of Emissions Reduction that, at present, there is insufficient supporting information on costs for partial CCS to be considered BSER for reconstructed utility boilers and IGCC units. Utility boilers are numerous and diverse in size and configuration, and the EPA does not have sufficient information on the range of specific configurations that would be necessary to estimate the cost of partial CCS, on either a source-specific or industry-wide basis. In particular, retrofitting a plant with partial CCS would entail integrating the carbon capture equipment with the affected unit's steam cycle (or with an external source of steam or heat) in order to release the captured $CO_2$ and regenerate the solvent or sorbent. The cost of a retrofit would depend on many site-specific details, including the space available for the capture equipment. The EPA lacks information on such details for a significant portion of the industry. Carbon storage technology remains under development and has yet to progress to the stage where it can be considered for purposes of identifying BSER. It is unknown whether injecting large volumes of CO2 at high pressure below ground may cause seismic events under some circumstances or result in effective containment. Moreover, many EGUs are not located near sites that are geologically or otherwise suitable for carbon sequestration.

**B. Building Block 1 (Heat Rate Improvements).**

<u>General</u> - EPA's assumption that the existing coal-based EGU fleet can improve its heat rate by an average of 6 percent, through a combination of improved operation & maintenance (O&M) and equipment upgrades is unfounded and incorrect. Since 2011, in preparation for compliance with the MATS rule, older power plants with higher heat rates that are no longer economically viable have been or are being retired. These retirements typically eliminate units with higher potential heat rate improvement possibilities from the fleet. Those units where investments have

already been made to improve operations are less apt to be retired and have less potential heat rate improvement opportunities remaining.

Heat Rate Effects Should be Assessed on a Net Basis - Historically, each set of emissions control regulations increases auxiliary power consumption by about 1% gross generation, translating directly to a decrease in heat rate efficiency. Emissions control equipment installations for forthcoming compliance with the MATS rule will have a similar detrimental effect on unit heat rates. If this trend continues, unit efficiencies will continue to decline. Net heat rate reflects the cost of generating electricity including the cost of auxiliary power consumed as part of the process. However, EPA has used gross heat rate for determination of heat rate improvement and related $CO_2$ mitigation potential in Building Block 1 which may lead to inconsistencies, confusion, and possible overestimation of the mitigation potential.

Issues with NSR - In addition, large capital projects designed to assist with unit efficiency improvements are subject to PSD according to EPA and have historically been the subject of litigation that has been filed by EPA and third party environmental groups against some coal-fired electric utility units. EPA and citizen plaintiffs have long targeted efficiency-improving measures like steam turbine upgrades in NSR enforcement suits alleging that such measures constitute "major modifications" triggering strict PSD permitting requirements. EPA acknowledges the issue, but merely states that it expects only a "few instances" in which an NSR permit would be required for energy efficiency projects. However, potential NSR concerns will continue to be a major impediment to energy efficiency projects unless EPA provides a clear and unequivocal statement that such energy efficiency projects do not trigger NSR. Unless EPA provides such a statement, it will fail to demonstrate the achievability of its proposed goals as required by Section 111.

EPA Misinterpreted the Sargent & Lundy (S&L) Study and Has Overstated Potential Heat Rate Improvements - EPA's assertion that certain heat rate improvement measures will produce sustainable efficiency improvements is overstated. The 6% plant specific efficiency improvements was based by EPA on a 2009 study by S&L, NETL studies and a series of hourly data from the Clean Air Markets Division. EPA has misinterpreted the results of the study and based their calculation of state-specific heat rate efficiency improvements, assuming the reductions are achievable on every EGU in a state on average. EPA recognized this assumption to overestimate potential heat improvements. The EPA's GHG Abatement Measures Technical Support Document (TSD) at 2-5 states:

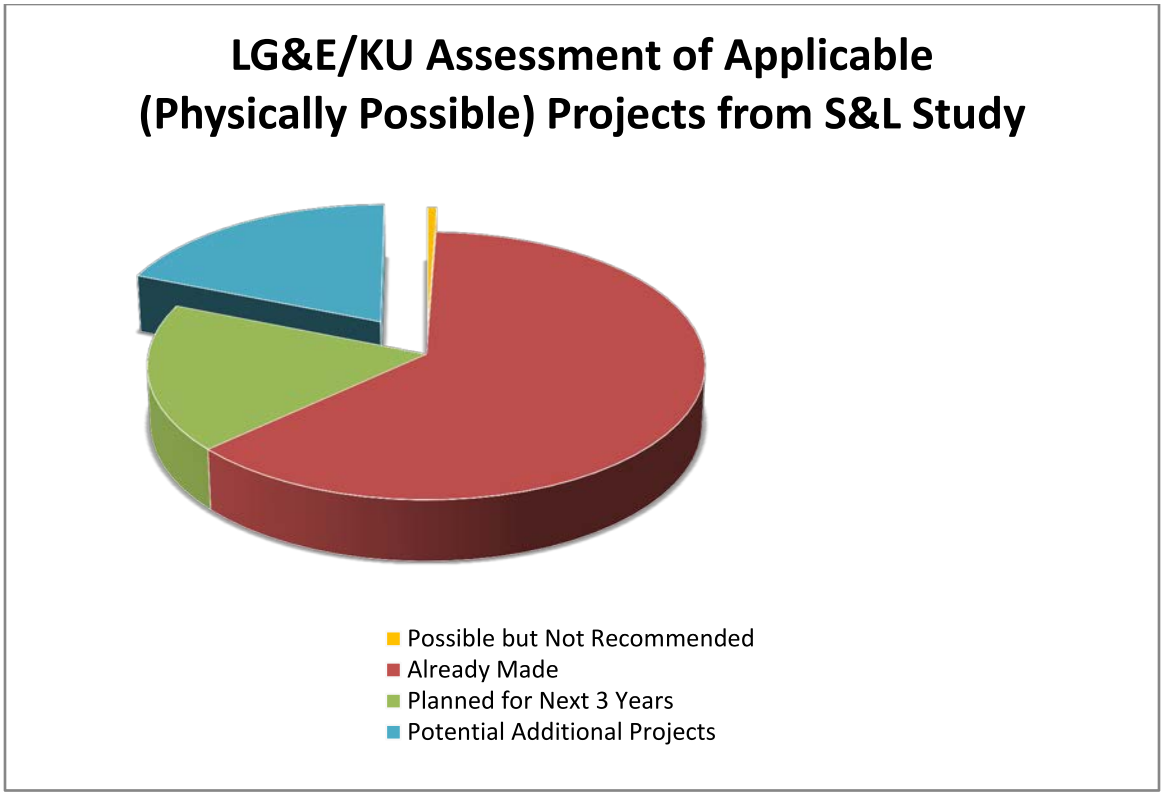
> *"All of the improvement technologies in Table 2-2 cannot necessarily be implemented at every existing coal-fired EGU facility in the U.S. electric utility fleet. The existing EGU design configuration and other site-specific factors may prevent the technical feasibility of using a given technology."*

In spite of this statement in the TSD, the improvements in the calculations EPA utilized for Building Block 1 assumes units in a state can achieve a 6% improvement on average. EPA must recognize that since improving heat rate translates to reducing the cost of operation, it has always been the common practice for operators of coal-fired electric utilities to seek and deploy cost-effective measures that would improve or preserve unit efficiencies through both capital and

O&M projects.  Although applicable regulations (e.g., NSR) may limit the amount of energy efficiency gains which might be achieved, operators of these facilities have continually sought any efficiency gains that are available under the constraints of the regulatory environment.

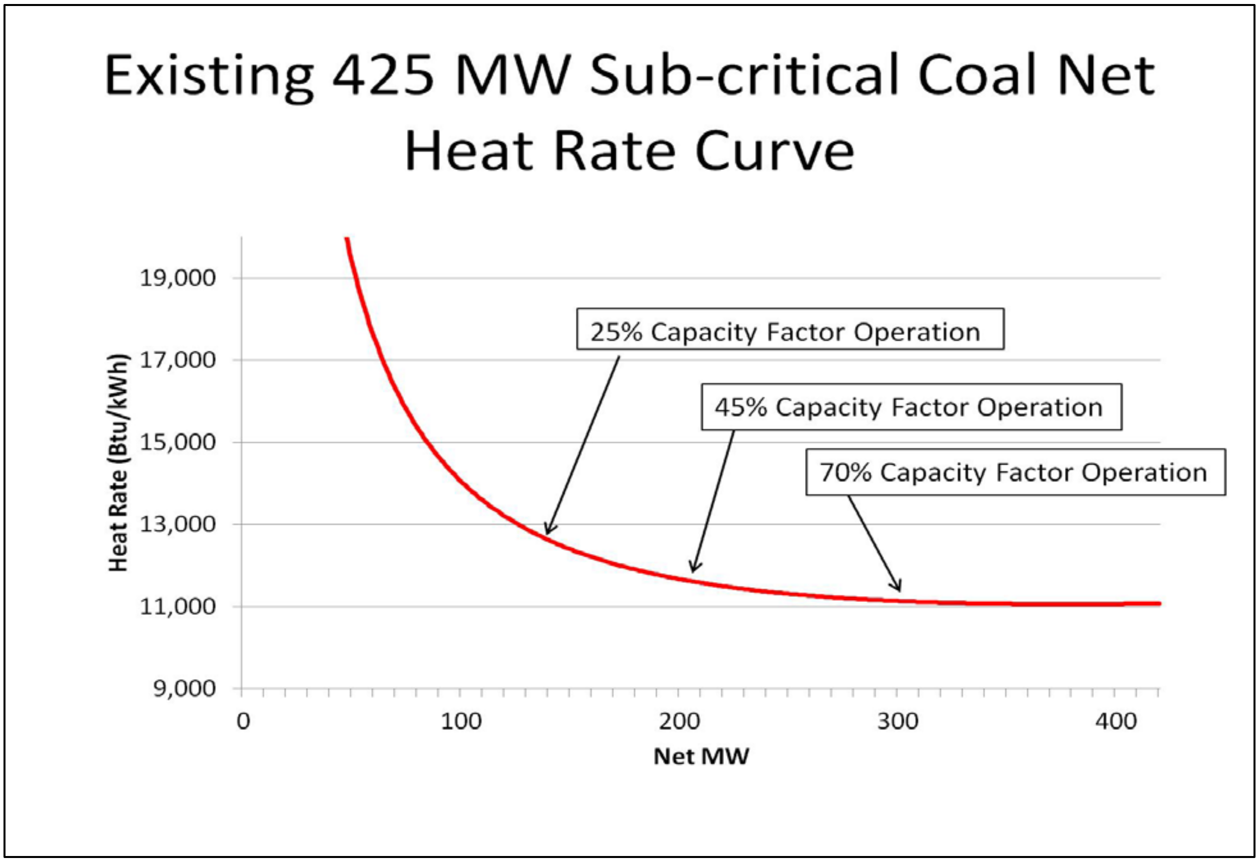
Within these regulatory considerations, LG&E and KU have already implemented most of the cost-effective improvements identified in the S & L study.   Many of the more significant improvement measures are planned for completion in association with the installation and replacement of air emission control systems to meet new requirements of the NAAQS and MATS regulations.  EPA should recognize that the addition of these control systems will decrease unit efficiency because of the added parasitic loads and increased flue gas system pressure drops.  As a result, remaining efficiency that can be gained at existing coal-fired utilities is minimal.  In addition, many accomplished gains in efficiency will diminish over time as natural degradation occurs.

LG&E and KU evaluated the S&L Study improvement options that might be applicable to the coal-fired units that will operate in compliance with the MATS rule and are expected to still be in operation beyond 2020.  The units evaluated relative to the S&L Study were its largest units: E.W.  Brown Unit 3, Trimble County Units 1 and 2, Mill Creek Units 1-4, and Ghent Units 1-4. Each improvement was rated as applicable, not applicable, or already in place/already planned.
There are 32 individual heat rate improvement measures in the S&L report that might be considered for each unit.  From an internal review of these possible measures  to consider in the LG&E and KU fleet, several measures are not applicable due to the physical configuration of plant equipment (i.e., cooling tower upgrades to units that do not have mechanical draft cooling towers, or VFDs on units with turbine driven boiler feed pumps).  From those measures that are physically possible (minus those deemed by S&L to have little or no effect on heat rate), the vast majority of remaining measures have already been completed as illustrated by the chart below. Of the remaining measures  that are still possible, many are planned for implementation within the next three years to offset heat rate degradation resulting from installation and operation of 10 new pulsed jet fabric filter systems, four new or replacement wet flue gas desulfurization systems, and 10 new dry sorbent injection systems.  However, most importantly, although LG&E and KU have implemented the majority of the improvements both possible and recommended by the S&L study, a look-back of CEM data measured and reported in accordance with 40 CFR 75 over the last 5 years shows that the total heat rate for all units has degraded by 0.4% on a gross weighted average basis.   On a net basis that accounts for application of pollution control equipment, the heat rate over the last five years for the same units has deteriorated by 1.1%. Clearly, improvements of 6% in heat rate are not achievable on the LG&E and KU units.




In summary, LG&E's and KU's internal review finds that (1) the S&L data were taken out of context by EPA and greatly overstated the amount of heat rate improvement that can be achieved, (2) heat rate improvements will naturally degrade over time, and (3) the additional pollution control equipment needed for compliance with the MATS rule will further deteriorate heat rate and overall unit efficiency.

Heat Rate is Degraded by the Effects of a Shift to "Load Following" - In addition, the impact of load following operations has significant impacts on heat rate performance as recognized in the TSD. In Kentucky, with multiple steel manufacturing operations, sudden load ramping requirements are a fact of life. The magnitude of the load changes are such that a single EGU cannot follow the load on a given day or season and many units are involved in load following operations. The EPA's statistical analytics seem to suggest each and every unit should be able to shift operation away from load following toward base load, which is not practical. In addition, EPA must consider the effect that shifting generation from coal-fired EGUs to existing NGCC units will have on the heat rates as described in Building Block 2. The impact of this re-dispatch will reduce the capacity factors and increase heat rate with a carryover effect on Building Block 1. As coal fired EGUs are utilized less and cycled more, unit efficiency will degrade. As an example, if KU's Brown Unit 3 were operated at lower loads (e.g. dropping from 300 MW to 200 MW average) to accommodate 100 MW of increased gas or renewable energy dispatch, its heat rate would be approximately 20% higher (worse) as depicted in the chart below.




## C. Building Block 2 (Increased Utilization of NGCC units).

EPA is proposing that it is achievable for affected EGUs in each state to shift generation from existing coal- and oil/gas-fired steam EGUs to existing natural gas combined cycle (NGCC) units until those NGCC units reach a statewide maximum capacity factor of 70 percent. EPA based this conclusion on its observation that of 464 NGCC plants it identified with generation data in 2012, 10 percent had a capacity factor of 70 percent or greater.

The only "existing" NGCC generation in Kentucky is LG&E's and KU's Cane Run 7 unit, which is currently under construction to replace coal-fired resources retired as a result of the MATS regulations. Any other increased utilization from existing NGCC units would have to be imported into the state. Reliance on out-of-state generation is concerning given the competition for energy resources between generating states and other importing states (as contemplated under Building Block 2). Transmission planning must be completed across import and export seams between the Transmission Planning and Balancing Authorities to verify enough Available Transfer Capability (ATC) exists to facilitate firm transmission transactions. Without sufficient firm transmission contract paths, congestion and reliability concerns will be created and/or exacerbated and could require transmission line construction. EPA should analyze and seek further information on potential reliability constraints from a generation and transmission line perspective prior to determining NGCC capacity and the appropriate NGCC re-dispatch capability.

LKE questions the legality of including re-dispatch as a component of determining BSER. However, if this component ultimately survives legal scrutiny, LKE supports allowing State Compliance Plans to utilize existing NGCC, CTs and New NGCC as an offset of existing coal-fired $CO_2$ emissions.

**D. Building Block 3 (Increased Deployment of Renewable Generation).**

The four parsed IPM runs that are available demonstrate that the Agency's Building Block 3 targets are far too costly and do not represent realistic estimates of the potential Renewable Energy generation available to achieve the Proposed Guidelines. According to EPA, the IPM is a "multi-regional, dynamic, deterministic linear programming model of the U.S. electric power sector that the EPA has used for over two decades to evaluate the economic and emission impacts of prospective environmental policies." GHG Abatement Measures TSD at 3-20. IPM is able to project least-cost capacity expansion and electricity dispatch while also accounting for constraints due to fuel supply, transmission, dispatch, and reliability. *Id.* EPA performed IPM modeling runs to assess how states would comply with the Proposed Guidelines under both state-focused and region-focused compliance approaches. Thus, the results of these IPM runs constitute EPA's estimate of representative scenarios in which the power sector is operating in compliance with the Proposed Guidelines at the least cost possible, within the constraints EPA imposes on the model.

As discussed above and to reflect an assertion provided by the Utility Air Regulatory Group, EPA is proposing to find that it is achievable for states to increase their overall Renewable Energy generation to 522,723 GWh by 2029, with an annual growth rate from 2020 to 2029 of roughly 7.1 percent. The target Renewable Energy generation levels that make up this total were used to calculate each state's interim and final $CO_2$ emission goals. Yet EPA's IPM model runs predict that actual Renewable Energy generation growth will be only a small fraction of this target under the least-cost approach to compliance with the Proposed Guidelines. IPM predicts that under both the state-focused and region-focused compliance approaches, Renewable Energy generation will reach only 356,063 GWh by 2029, and will grow at an annual rate of 1.1 percent from 2020 to 2029. (Marchetti Report). This level of generation is only 1.7 percent greater than the Renewable Energy generation that EPA predicts in 2029 under its own Base Case analysis, and is *actually 7.6 percent lower* than the EIA predicts will occur in 2029 *in the absence of any emission guidelines*. EPA's own analysis severely undermines the Agency's prediction of the level of increased Renewable Energy generation that is achievable, and demonstrates that the Agency has failed to accurately consider factors such as cost and feasibility. The IPM results suggest that rapid growth in Renewable Energy generation is so costly that states are able to achieve only negligible incremental increases in Renewable Energy generation above the status quo (at best), and they must instead rely more heavily on other components of EPA's selected BSER in order to comply with the Proposed Guidelines. This, in turn, will increase the cost of those other building blocks in ways that EPA has failed to analyze in the Proposed Guidelines.

EPA has assumed that Kentucky will achieve its generation needs by deploying up to 2% renewable generation (approximately 1,734 GWh by 2030). Interestingly, the IPM models only deployed 9 MW of new wind capacity by 2020 in the policy case, according to the Resource Adequacy and Reliability Analysis TSD Appendix A2 on page 14 for SERC-N region. Data from a recent LKE capacity solicitation indicates to meet 1,734 GWh of renewable energy from the state of Kentucky and nearby states would require the equivalent of over 670 MW of wind or 1,200 MW of solar capability. This amount of renewable energy resource would most likely result in significant transmission infrastructure needs for either in-state or out-of-state sources. Reliance on out-of-state generation is concerning given the competition for energy between generating states and other importing states (as contemplated under Building Block 3). Again in this instance, Transmission planning must be completed across import and export seams between Transmission Planning and Balancing Authorities to verify enough Available Transfer Capability (ATC) exists to facilitate firm transmission transaction. Without sufficient firm transmission arrangements, congestion and reliability concerns are exacerbated and could require further transmission line construction.

By the dynamics of the proposed compliance calculation, any over-estimation by EPA in setting the reduction goals based on renewable energy development and utilization in Kentucky will need to be offset by over twice the amount of reduction from fossil sources. EPA should analyze and seek further information on potential reliability constraints from a generation and transmission line perspective prior to determining RE capacity and the appropriate RE re-dispatch capability.

LKE is seeking approval to construct a proposed 10 MW solar project that will require approximately 100 acres of available land at an existing site. With that as the expected land requirement, to install 1,200 MWs of solar energy to meet the Building Block 3 energy calculation above, it could require up to 12,000 acres for solar panel installations, which is not a practical assumption.

Similarly, to provide 670 MW of wind generation in Kentucky, over 250 wind generators would be required. As the EPA's IPM model only deployed 9 MW of wind generation in Kentucky, the balance of wind energy would have to be imported, triggering the need for fully evaluating the transmission system capability described above.

EPA has also failed to consider all zero carbon emitting resource available in Kentucky with the exclusion of new or upgrades hydroelectric energy. In this case, hydroelectric energy resources operated by LKE are first to dispatch when available and thus would off-set fossil emissions. Upgraded hydroelectric generation which occurs after the baseline period should be included in state compliance demonstrations.

**E. Building Block 4 (Increased End-Use Efficiency).**

EPA's calculation of end use efficiency based on total sales begins Kentucky at 0.22% in 2017 with ramping ranging up to 1.5% per year by 2025 and then sustaining that rate into the future (reaching 10.57% by 2030). This assumption is based on the 12 best States' efficiency program gains and, for Kentucky, results in approximately 9,322 GWh (cumulative) of avoided energy production in the states' goal calculation. EPA's basis for achieving large reductions through energy efficiency is not well-supported. EPA assumes over 450 TWh in cumulative savings from EE programs nationally, which is almost twice the estimated savings found in an Institute for Energy Innovation white paper (www.deisonfoundatin.net/iei/IEE_FactorsAffecting USElecConsumption_Final.pdf).

Likewise, EPA's own GHG Abatement Measures Technical Support Document states:

> *"Limited empirical data suggests the reasonableness of this approach; however comprehensive data, across all regions and states, does not exist because these levels of performance have not been achieved and sustained nationwide previously." (Reference: GHG Abatement Measures Technical Support Document, Pg. 5-37).*

Additionally, the report *"U.S. Energy Efficiency Potential Through 2035"* published by EPRI in 2014 indicates an achievable range of energy efficiency potential from programs equivalent to an annual incremental electricity savings of 0.5 to 0.7% of retail sales through 2035. EPA's assumed annual incremental ramp rate is unreasonable and overstated.

The level of EE measures that EPA included in Kentucky's goal calculation is set at an amount that greatly overstates the potential achievable results. As part of an LG&E and KU evaluation, measurement, and verification processes, The Cadmus Group, Inc. ("Cadmus") was commissioned to perform an *Energy Efficiency Potential Study* ("*EE Potential Study*"). The *EE Potential Study* involved separate assessments of energy-efficiency potential for electricity in the residential and commercial sectors for LG&E and KU, considering a wide range of energy-efficiency technologies. Results indicate a range of 941 GWh to 1,478 GWh of achievable electricity savings, representing 3.9% to 6.1% of forecasted retail sales in 2033. The *EE Potential Study* stated that the Companies are currently on track to exhaust their achievable energy-efficiency potential by 2018. Consequently, it is inappropriate to assume that energy efficiency is a limitless resource. Energy efficiency is a limited resource which has increasing marginal costs. Thus, the ability to sustain approximately 1.1% of energy efficiency year-over-year is likely not achievable.

## IV. State Compliance and Implementation

### A. EPA Should Provide the States with Flexibility Necessary for Preparation of Effective SIPs.

<u>States Must Have More Than One Chance To Develop An Acceptable SIP</u> - The rule as proposed by EPA attempts to provide avenues of flexibility as guidelines for states to develop compliance plans. The rule includes a large number of proposed guidelines and associated options for states to demonstrate compliance, however, there is much uncertainty and questions regarding not only the validity of the BSER determination, but the measures that will be allowed and how those measures will be implemented in state plans to ultimately demonstrate compliance. Considering the complexity of this rule, the large number of uncertainties, and the potential impact on electric utilities and consumers within each state, the EPA must provide a vehicle that allows for states to have more than one chance at getting the SIP correct.

<u>Timing of Reductions</u> - EPA indicates that states will need to begin taking action to reduce emissions *before* the interim compliance period starts in 2020 in order to achieve the 10-year interim emission rate. For example, EPA projects that many states would begin ramping up end-use efficiency programs and renewable generation projects in 2017 in order to attain the annual

levels of end-use efficiency and renewable generation included in determining each state's emission rate goals. While EPA assumes that states will commit to early reductions in order to help achieve the interim and final goals, the guidelines focus on accountability and compliance in the interim period.

Further complicating matters is the process states must follow in developing and getting their plans approved by EPA. Although state plans are due in 2016, EPA has offered states the option of seeking an additional year (for an individual state plan) or two (for multistate plans). Once submitted, EPA has one year to approve a plan. While additional time to develop compliance plans is a welcome flexibility that recognizes the challenge for states in crafting workable plans, this additional time means that it could be as late as 2018 or 2019 before a state has a final approved compliance plan. States that do not have or are not planning to rely on existing state programs (e.g., RES, EE programs) would have very little time to get started on the early reductions that could be used towards compliance.

The biggest driver of many state GHG reductions is the potential for increased utilization of existing NGCC units or renewable energy, which mainly occurs before 2025 under EPA's assumptions. In fact, EPA's own analysis indicates that most of this shift occurs before 2020, including 46-49 GWs of coal-based unit closures in addition to closures that have already been announced, in part due to compliance with the Mercury and Air Toxics Standards. EPA assumes that adequate infrastructure to support coal-based unit closures and increased utilization of NGCC units can be put in place in as little as two or three years, but this is not realistic given the time needed for both permitting and construction. With respect to importing energy from other state's NGCC resources, transmission congestion may develop which would necessitate the construction of high voltage transmission lines. As identified by Southwest Power Pool's *"Grid Reliability and Build-out Issues"* analysis issued October 1, 2014, this process can take 8 to 10 years and add significant cost. NERC also raised the same concerns in the November 2014 study *"Potential Reliability Impacts of EPA's Proposed Clean Power Plan,"* stating on page 20:

> *"… Mitigating transmission constraints identified from the proposed EPA regulations in a timely way, consistent with CPP targets, presents a potential reliability concern. Construction of new interstate high-voltage line can range from 5 to 15 years depending on the voltage class, location, and availability of highly skilled construction crews…"*

Consequently, any assumptions that transmission infrastructure can be implemented by 2020 is not supportable.

<u>Interim Goals</u> - The proposed rule includes a large amount of information and large number guidelines, many of which continue to lack clarity, which will potentially have a dramatic effect on each state and consumers. It is important that a rule with this potential effect follow a timeline sufficient to develop clarity and a reasonably functional process for implementation. As there is no statutory requirement that reductions be achieved on a particular schedule and to address concerns about the pace and timing of reductions, EPA could relax the schedule and still achieve the proposed reductions on a timely basis. To provide the necessary relief, EPA should finalize the proposed 2030 goals and allow increased flexibility for states to select the interim compliance goals and glide path timeline for meeting the 2030 goal. Should EPA deem it

necessary to have a specific interim target, EPA should allow individual states to select the interim goal as long as they demonstrate compliance and meet either the final 2025 or 2030 emission rate goals at their discretion. In providing this flexibility with the timeline, the EPA should allow states to use state-specific information regarding energy efficiency and estimated energy savings. Finally, the EPA should allow states to include non-binding milestones as a means of measuring and ensuring progress toward the final goal, in lieu of interim compliance periods that serve as binding annual requirements.

**B. States Should Be Entitled to Full Credit for Relevant Reductions.**

Full Credit for Retirements – EPA should expressly allow states to rely on unit retirements occurring after the baseline year(s) to meet Section 111(d) goals. Further, retirements should be given equal credit under a rate-based or a mass-based program. As proposed, the rule would not allow states that have adopted a rate-based goal to fully benefit from unit retirements if the replacement generation comes from out-of-state. This is because, in coal-heavy states, the pre-retirement and post-retirement emission rate for the state will remain largely unchanged, even if the generation is not increased in-state. In states that adopt a mass-based standard, EPA should allow all EGUs that a company or state has agreed to retire to be included in the state's "reference case." The generation from the reference case would then be used to determine the mass-based goal. If generation from the retiring unit is not built into the reference case, then the lower generation and emission rate would result in a lower mass-based target. The purpose of the retirement should be irrelevant, since all existing EGU retirements result in substantial reductions in GHG emissions. Ensuring that states and companies receive credit for retirements will help ensure that utilities and states that are planning retirements of existing coal plants are not penalized by that action.

Remaining Useful Life - An arbitrary end of life for an EGU cannot be assumed in development of state compliance plans to meet performance targets. Generating units equipped with appropriate emission controls and subject to prudent ongoing maintenance and investment can achieve several decades of useful and economical service beyond an accounting “book life.” LG&E and KU have long conducted prudent utility practice for maintaining and maximizing the economic viability of their units. Investment decisions are viewed over a long horizon with consideration of current and expected environmental requirements that can be economically added to the unit.

Baseline and Accounting of Reductions - With this proposal, EPA has determined that if the reductions are made using 2012 data as a baseline, the mass emissions of GHG from EGUs will be approximately 30% less than emissions in 2005. This estimation takes into account the measured effects of all actions that have reduced CO2 emissions from EGUs between 2005 through 2012. However, the use of a single year in establishing the baseline does not account for unusual operational situations and conditions driven by the economy. For example, a single year baseline might occur in a year where there were unusually high or low amounts of rainfall impacting hydroelectric production. Likewise, abnormally low or high natural gas prices can skew the normal dispatch order of EGUs. In 2012, due to low natural gas prices for the LG&E and KU fleet, simple cycle combustion turbines were called into service at almost twice the average run time as the previous 10-year average rate. Therefore, EPA should allow states to use a three-year average period to set the baseline rate for calculating the goal (e.g. a consecutive 3-

year period between 2005 and 2012 or perhaps the period from 2010 – 2012) to help alleviate any anomalies that may result from specifying a single year baseline period. EPA should permit the state plans to begin counting reductions immediately following the end of the baseline period. Also, EPA should allow states to count reductions from any actions that occur after the baseline period which support meeting the final 2030 goal.

EPA Has the Authority to Allow State Plans to Adopt a Portfolio Approach - States have the responsibility under section 111(d) to set standards of performance in their implementation plans. Standards of performance are standards for emissions of air pollutants that *reflect* BSER. However, nothing in the statute requires that compliance with such standards be limited to application of technologies or approaches EPA uses to determine BSER. As EPA points out, policies and measures that indirectly reduce emissions at affected EGUs could be considered part of a plan *for implementation* of standards of performance. EPA has appropriately recognized that it has authority to approve state implementation plans that include options to utilize measures implemented by entities other than EGUs – what it deems a "portfolio approach" – to provide compliance flexibility.

Treatment of New NGCC Units and Accounting for Related Emissions - States have clear discretion to include new NGCC units as part of compliance plans should they choose to do so. Although new NGCC will be subject to Section 111(b) standards and cannot be considered in determination of BSER for existing units, states should be given wide latitude to include new NGCC for purposes of calculating compliance for existing units. However, EPA has not provided clear guidance as to how the emissions and generation from these units would work into the compliance calculation.

New NGCC units have been promoted by EPA in the proposed GHG NSPS as the standard for low emitting and efficient electric generating unit technology. The EPA should further promote new NGCC technology by providing clear procedures for its inclusion in state plan compliance demonstrations for existing sources under both rate-based and mass-based programs.

Although new NGCC generation may not be used in determining BSER, states should have the flexibility to incorporate new NGCC in compliance plans. The use of new NGCC to offset the use of higher emitting affected sources would result in reduction of mass emissions of $CO_2$. The effect on mass emissions could easily be directly measured and reported in accordance with existing CEMS procedures.

### C. The States Should Have Primacy in Enforcing Performance Goals.

While EPA has the authority to provide flexible compliance options, EPA's enforcement authority under Section 111 is clearly limited to new and existing sources in the listed source categories. Section 111 certainly does not provide EPA with the authority to impose enforceable obligations on entities that may be involved in implementation of the "outside the fence" measures considered by EPA in setting its proposed performance goals. Therefore, to the extent that a regulated source adopts a compliance strategy involving implementation of "outside the fence" measures by non-jurisdictional entities, it is sufficient for a state implementation plan to provide federal enforceability for the performance goal imposed on the regulated source, rather than compliance measures performed by non-jurisdictional entities. The source (or state) relying on outside the fence reductions has the ability to make measures performed by non-jurisdictional entities legally enforceable through the mechanisms of contract or agreed order. However, any requirements for federal enforceability should be deemed satisfied so long as federally enforceable obligations in the nature of performance goals are placed on the state and regulated sources subject to the statutory requirements. To expand federal enforceability beyond those entities would exceed the scope of EPA's authority under Section 111.

### D. EPA Should Provide a Framework for Managing Interstate Implications of the Program.

EPA's proposed emission guidelines provide little information on how the various states may develop multi-state agreements other than the requirement that multi-state program must be enforceable, verifiable and ensure that emission reductions are not double-counted. In regions where multi-state agreements already exist, it is likely that this method of compliance will continue and perhaps provide a cost savings to the overall region. But in those states where no multi-state program currently exists, EPA's proposed guidelines will require numerous state agencies and other organizations that are not traditionally involved with the CAA to work together in a regulatory context. Because of the complexity of these multi-state arrangements, the widespread usage of this approach in the near-term is unlikely.

For fossil-fueled EGUs subject to these regulations, a compliance program which governs only the emissions sources within that state would be much more easily managed by one state regulatory agency. Thus, from a verification and enforcement standpoint we see significant advantages to applying all actual $CO_2$ emissions to the state in which they are generated. We agree with EPA's proposal that states take responsibility for all $CO_2$ emissions generated by in-state fossil-based EGUs, despite the fact that many companies own and operate EGUs in one state that serve load in another state.

As a policy matter, EPA should not intrude into areas which are unregulated by the CAA and thus appropriately left to the state's decision. Requiring the use of a renewable energy standard or the deployment of end-use efficiency programs are inherently state decisions that should not be federally mandated. However, there is a problem in limiting all compliance actions to those within the state's borders and this is particularly true for renewable electric generation. A significant percentage of renewable generation is located in one state, but the energy is consumed in another. Because of the diversity and spatial distribution of our nation's renewable energy resource capabilities, some states are capable of generating renewable energy at a much lower cost than other states. Thus, in an effort to minimize the cost of compliance, the state's compliance plans should allow for this type of interstate transfer of carbon-free generation (MWH) or the credit for this type of generation. To avoid contentious negotiations between states agencies, we recommend that EPA establish procedures in their final regulations that provide clear guidance on the process in which carbon-free generation could be tracked on an interstate basis to avoid double counting.

We suggest EPA consider being a clearinghouse for this carbon-free generation to ensure the transferred MWH are accurately accounted for both from a generation and a usage standpoint. This clearinghouse approach would expedite the use of interstate renewable generation without the need for lengthy negotiations between the various state agencies. LKE has identified through these comments Kentucky's difficulties in achieving the associated $CO_2$ emission reductions estimated by EPA under Building Blocks 1 and 4; therefore it is imperative that the states' compliance plans can achieve overall compliance through increase usage of renewable energy across state lines.

The proposed EPA guidelines suggest that states which are net importers of power discount and transfer their reductions that were achieved by end-use energy (EE) efficiency programs to the states where the generation occurred, since a portion of the energy usage that was displaced was located in a different state. We see this transferring or discounting process to be unnecessarily burdensome and perhaps impossible where multi-state RTOs exist. Since EPA's end-use energy efficiency with Building Block 4 establishes the same 2030 annual cumulative energy efficiency target of 1.5% for all states, it is unnecessary to add the burden of determining the generating source for each MWH consumed in every state. EPA should simply allow the states to adjust their MWH generated by the state's achieved level of end-use energy efficiency.

**E. EPA Has Failed to Provide Clear and Simple Guidance Necessary for Mass Cap Translation.**

LKE supports EPA's proposal that states be allowed to translate the emissions rate goals into mass-based goals to provide flexibility for utilities to meet either rate-based or mass-based targets that are equivalent to the rate-based goals proposed by EPA. However, EPA must clearly outline the methodology for states to set mass-based standards, while still providing flexibility to use alternate methodologies to account for diversity among states. EPA also must clarify how states are to demonstrate projected emission performance under a mass-based plan, which requires the state to project the $CO_2$ emissions outcome that would be achieved under the suite of requirements, programs, and measures in its plan. This guidance should ensure that all actions that reduce $CO_2$ emissions are counted under a mass-based program. EPA's methodology should result in mass-based goals that are no more stringent than rate-based goals. EPA should clarify that the stringent mass-based goals identified in the Translation TSD appendix are not binding on the states and do not establish a standard for determining the adequacy of state calculations. As written, EPA's proposed emission guidelines do not explain exactly how a state should go about calculating a mass-based rate. In the Technical Support Document entitled *Projecting EGU $CO_2$ Emission Performance in State Plans* ("Performance TSD"), EPA states generally that a mass-based $CO_2$ emission performance goal is calculated by projecting the tons of $CO_2$ that would be emitted during a state plan performance period (e.g., 2020-2029, 2030-2032) by affected EGUs in the state if they hypothetically were meeting the state rate-based $CO_2$ emission performance goal for affected EGUs established in the emission guidelines (Performance TSD at 13). EPA next explains that, when demonstrating projected emission performance under a mass-based plan, a state would project the $CO_2$ emissions outcome that would be achieved under the suite of requirements, programs, and measures in its plan. EPA does not provide, however, any details on how to perform the projections needed to calculate total tons of $CO_2$ emissions over each plan performance period.

LKE urges EPA to provide clear and simple guidance for states to use in translating a rate-based goal to a mass-based goal (*See* Fed. Reg. at 34912; Performance TSD at 45). For example, EPA should expressly allow a state, in determining its mass cap, the flexibility to use a reasonable estimate of future generation from affected units including utilization of the values the EPA assumed in their development of the target emission rates. EPA should expressly confirm that such a simplified and conservative approach would be approved, if selected by a state. If the state desires to take other factors into account, EPA's guidance should specify acceptable analytical methods and tools, as well as default input assumptions for key parameters that will likely influence projections, such as electricity load forecasts and projected fossil fuel prices. States should be allowed to deviate from these default methods and assumptions as long as they provide a reasonable justification. Following the guidance would provide a streamlined path for EPA approval of emissions projections, but would still allow states the flexibility to use other approaches, subject to EPA review. This guidance should ensure that all actions that reduce $CO_2$ emissions are counted under a mass-based program. Importantly, EPA should expressly allow states to rely on unit retirements occurring after the baseline year(s) to meet Section 111(d) goals and allow the state to include emissions from those facilities in the "reference case" regardless of the reason for retirement of those units.

## V. IPM Issues

### A. EPA's Assessment of Resource Reliability and Adequacy is Flawed.

EPA used its Integrated Planning Model (IPM) to conduct the resource adequacy and reliability analysis. Included in the docket is a Resource Adequacy and Reliability Analysis Technical Support Document (TSD). The TSD summarizes the changes in operational capacity, reductions in excess reserves and retirements and new capacity and additions that EPA's analysis predicts will occur as a result of the proposed emission guidelines. These retirements occur by 2020. In total, the operational capacity decreases by 30 GWs. EPA states that many of the plants that are projected to close will not need to be replaced and that the retirements are distributed throughout the grid, minimizing impacts at the regional level. While some retirements are replaced with new generation, IPM transfers reserves from neighboring regions, rather than supply reserves within a region, where it is economic to do so.

The impacts from the retirements of Designated Network Resources on the reliability of the grid must be studied by transmission operators and reliability organizations to determine what specific impacts will be created by these changes in supply. Until such reliability assessments are performed by transmission operators in Kentucky and the surrounding regions, the exact impacts on reliability, as well as any recommended transmission infrastructure modifications, cannot be known. It is reasonable to expect there will be reliability concerns and increased congestion on the grid that may lead to power shortages until such time as solutions can be developed and implemented. Some solutions may lead to construction of new transmission facilities. Planning, permitting and construction of bulk electric system transmission lines can take 8 to 10 years. With State plan approvals by the EPA (either individual or regional) not completed until as late as 2018 or 2019 with extensions, is will not be possible to place such facilities in service before later in the next decade.

Despite EPA's assertions about the utility of their model, IPM may not be the appropriate tool to assess resource adequacy or reliability. In particular, it is not clear that the IPM limits on transfers between regions appropriately capture actual transmissions constraints. It is also not clear how or if IPM addresses RTO/ISO seams issues, which affect the deliverability of power even when there is a surplus of generation. Further, IPM's regions do not align with the planning regions used by the RTOs/ISOs. As EPA notes, IPM also does not address intra-regional transmissions constraints. These limits impact EPA's ability to address local reliability concerns.

If IPM does not accurately capture transmission and other constraints on the deliverability of energy or capacity, there may be areas that require transmission upgrades that are not addressed by EPA's resource adequacy and reliability assessment. Accordingly, new transmission infrastructure may be needed. Transmission lines take, on average, 10 years to plan, permit and build. If states submit compliance plans in 2016, at the earliest, any new transmission that could be needed to implement these plans would not be completed until the latter half of the next decade.

The TSD states that, where needed for reserve margin, retiring capacity is replaced by new generation sources, including 10 GWs of wind. The TSD incorrectly discusses wind generation as if it can provide the same capacity as baseload resources. It is inappropriate to assume that wind can provide capacity to ensure reliability.

In particular, periods of peak demand often occur when wind is minimal (i.e., hot summer days/nights with stagnant air conditions). Additionally, during the coldest winter days/nights, wind conditions do not consistently support generation. During these periods, it is a high risk to assume that 10 GWs of wind will be available.

### B. EPA Has Incorporated Other Incorrect Model Assumptions.

EPA's IPM model assumptions are incorrect with known errors. The model inputs show retirement of the E.W. Brown Units 1 and 2. However, KU has no plans or announcements for retirement of these units. Additionally, the model does not show mercury controls for E.W. Brown Unit 3, Mill Creek Units 1 and 2, or Trimble County Units 1 and 2. Although it may have a small effect, negative energy for KU's Tyrone Station in the 2012 actual data used for the goal calculation should be excluded because Tyrone did not operate in 2012.

Other questionable retirements just within Kentucky include TVA Shawnee, Big Rivers Electric Corporation's Reid Unit 1, and the Cooper and Dale Stations owned by East Kentucky Power. The model also incorrectly shows continued operation of the Paradise Coal Units 1 and 2.

A related limitation of IPM is that this model does not represent unit commitment and electric power plant hourly dispatch in a detailed manner. Research that EPRI has done shows that important insights can be gained when electric sector models capture positive and negative correlations between load, renewable energy resource variability, and uncertainty across adjacent regions given that renewable resources are non-uniformly distributed in space and time. EPA should consider enhancing the treatment of renewable energy in IPM and to complement the IPM analyses with more detailed, unit commitment modeling.

## VI. NODA

On October 28, 2014, EPA issued a NODA related to their proposed emission guidelines. With this notice, EPA provides concepts for consideration and comment relating to some technical issues and data that they characterize as consistently raised in their meetings with stakeholder groups. Three main topics are included:

1. Glide path – timing of emissions reductions between the interim goal in 2020 and the final goal in 2030;
2. Building blocks – treatment of natural gas and renewables in the proposed rule; and
3. State goal calculations – application of the best system of emissions reduction to each of the building blocks.

### A. Additional Flexibility Regarding Schedule is Appropriate, But a Regional Approach Could Significantly Lower Kentucky's Reduction Target.

Within the NODA, EPA claims the concepts for consideration are in response to comments from meetings with stakeholders to provide a more fair assessment of Building Blocks 2, 3 and 4; changes to the formula for calculating the goal; and more flexibility with respect to the timeframe of implementation. LKE's review of the NODA finds the recommendations regarding the implementation schedule may be more favorable and provide states additional flexibility toward a glide-path approach. However, the considerations EPA has outlined relative to the other topics, particularly a regional assessment of Building Blocks 2, 3, and 4 could result in significant reductions to Kentucky's target emission rate. Based on calculations performed by the Kentucky Energy and Environment Cabinet, Kentucky's target could change from the original proposal of 1,763 lbs $CO_2$/net MWh by 2030 down to as low as approximately 1,034 lbs $CO_2$/net MWh, if adopted to the full extent of the potential described in the NODA.

### B. The Regional Approach Contradicts the Assumptions Underlying the Building Blocks of EPA's Original Proposed Guidelines.

Relative to Building Blocks 2, 3, and 4, the original proposed rule utilized inputs and assumptions for existing and potential resources for reduction of $CO_2$ from affected electric generating units on a state-specific basis to develop a state-specific target emission rate. The concepts of the NODA do not change the inputs and assumptions for each state; however, the NODA applies them on a regional basis instead of a state-specific basis. The shift from a state implementation plan to more of a "regional implementation plan" is to "levelize" the emission targets both regionally and nationally. One of the proposed regional options in which Kentucky is listed is in the SERC Region along with Illinois, Tennessee, Missouri, Alabama, Georgia, North Carolina, South Carolina, and parts of Louisiana, Virginia, and Arkansas. This inflates the average amount of NGCC and renewable energy that could be applied to the state's 2030 goal calculation.

The following is a brief description of primary issues and comments sought in EPA's NODA:

- **Shift to Natural Gas Issues -** Building Block 2 that EPA utilized in the original proposal implements a shift of generation to existing natural gas combined cycles assuming an increase from a national average utilization factor of 55% to 70%. Since Cane Run 7 is the only affected unit in Kentucky under Building Block 2, the generation shift is only assumed to be 2% of total fossil fired generation for the state.

  The concepts for consideration in the NODA expand the utilization of natural gas to include co-firing natural gas, in addition to eliminating more existing coal-fired generation to be replaced by new NGCC. The NODA discusses increasing the gas re-dispatch/utilization for Kentucky's goal calculation and considers a range for a regional shift of between 12% and 55%. At the minimum value, which EPA discusses in the NODA, Building Block 2 for Kentucky's calculation would increase the loss of existing coal generation from about 2% up to 12% and potentially as high as 45%.

  In addition to previous comments herein identifying both NSR and BSER implications for the expanding use of natural gas proposed by the NODA, LKE is concerned about the capacity of the existing natural gas infrastructure to accommodate such an increase in use and the lack of such infrastructure at all the coal plant locations necessary for co-firing. The increased utilization of natural gas posited in the NODA significantly aggravates the NERC concerns expressed in their November 2014 report, *"Potential Reliability Impacts of EPA's Proposed Clean Power Plan,"* which stated:

  > *". . . . the EPA concludes that the power industry in aggregate can support higher gas consumption without the need for any major investments in pipeline infrastructure. However, here are a few critical areas that likely will need additional capital investments."*

  Further, NERC states:

  > *"Timing of these investments is also critical as it [can] take three to five years to plan, permit, sign contract capacity, finance, and build additional pipeline capacity, in addition to placing replacement capacity (e.g., NGCC/CT units) in service. The proposed CPP timelines would provide little time to add required pipeline or related resource capacity by 2020."*

- **Renewable Energy Issues –** The regional considerations offered in the NODA relative to renewable energy (Building Block 3) would change the original renewable energy target for Kentucky. The NODA would increase the renewable energy component from Building Block 3's target calculation from 2% up to 13% for the state. In comments filed by EPRI in the docket for this rule, EPRI accurately points out that assuming state equivalency for regional calculations of renewable resources is problematic. Each state has drastically different renewable resource potential. Additionally, the concerns regarding transmission capacity and double counting for importing renewable energy from the original proposal is clearly exacerbated by the regional approach in the NODA.

EPA should not adopt a regional approach in the calculation of Building Block 3 effects on Kentucky.

- **End-use Energy Efficiency Issues –** Similarly, a regional concept of reductions associated with energy efficiency programs (Building Block 4) would increase EPA's calculation component of avoided MWs under Building Block 4 for Kentucky from 10% to 13%. As stated previously in these comment, LKE believes the energy efficiency component was overstated by at least 75% based on our energy efficiency potential identified by the Cadmus study. Increasing the calculation for Kentucky to 13% will be even more problematic for the state. We urge EPA to avoid utilizing a regional approach for Building Block 4.

- **Changes to Formula for Goal Calculation Issue –** EPA is additionally seeking comment on changes to the goal calculation formula. Presently, for Building Block 2 (shift production to NGCC), the proposed formula offsets 1 MWh of fossil steam generation and corresponding emissions from the 2012 baseline levels for every 1 MWh of incremental NGCC generation (subtracting emissions from the numerator and generation from the denominator), reflecting the assumption that the shift to NGCC generation will replace fossil steam generation. However for Building Blocks 3 and 4, the formula adds Renewable Energy and Energy Efficiency to 2012 baseline generation in the denominator, but does not subtract or off set emissions in the numerator. EPA is requesting comments on two alternatives:

    1. Replace all historical fossil generation on a pro rata basis by assuming Renewable Energy and Energy Efficiency generation directly replaces 2012 fossil generation in proportion (i.e., pro rata coal and gas) to their historical generation; or

    2. Prioritize replacement of historical fossil steam generation similarly as (1) above, but by first replacing fossil steam generation to below 2012 levels and then applying the remaining incremental Renewable Energy and Energy Efficiency to gas turbine generation and emissions.

    LKE's concerns with either of these methodologies are similar. The EPA assumes that all Renewable Energy and Energy Efficiency generation will displace existing fossil emissions, which would not necessarily be the case. In the triennial Integrated Resource Plan (IRP) filing process required by the Kentucky Public Service Commission, LKE includes Energy Efficiency and DSM program as resources to meet future energy requirements from consumers. For IRP purposes, these resources serve to avoid the construction of new electric generating resources rather than reduce utilization of existing fossil generation. The proposed formula changes for the goal calculation therefore would penalize the state's existing Energy Efficiency programs.

## VII. Conclusion

In conclusion, under both the emission proposed guidelines and approaches referenced in the NODA, EPA has exceeded its statutory authority under Section 111(d). Setting aside the legal objections, the target assigned to Kentucky in EPA's proposed emission guidelines will pose a significant challenge for the state. Under the regionalized approach referenced in NODA, Kentucky's target may prove virtually unachievable under the constraints faced by the state, with potentially devastating impacts on Kentucky's economy.