a PPL company

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Jeff DeRouen, Executive Director
Public Service Commission of Kentucky
211 Sower Boulevard
P. O. Box 615
Frankfort, Kentucky 40602

RECEIVED
AUG 09 2011
PUBLIC SERVICE COMMISSION

August 9, 2011

RE: ***The Application of Kentucky Utilities Company for Certificates of Public Convenience and Necessity and Approval of Its 2011 Compliance Plan for Recovery by Environmental Surcharge***
Case No. 2011-00161

Dear Mr. DeRouen:

Enclosed please find an original and fifteen (15) copies of Kentucky Utilities Company's (KU) supplemental response to Question No. 39 of the Commission Staff's First Information Request dated July 12, 2011, in the above-referenced matter.

Should you have any questions regarding the enclosed, please contact me at your convenience.

Sincerely,

Robert M. Conroy

cc: Parties of Record

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
COUNTY OF JEFFERSON)

The undersigned, **Gary H. Revlett**, being duly sworn, deposes and says that he is Director – Environmental Affairs for LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Gary H. Revlett
Gary H. Revlett

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 9th day of August 2011.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:

November 9, 2014

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION OF KENTUCKY UTILITIES	)	
COMPANY FOR CERTIFICATES OF PUBLIC	)	
CONVENIENCE AND NECESSITY AND	)	
APPROVAL OF ITS 2011 COMPLIANCE PLAN	)	CASE NO. 2011-00161
FOR RECOVERY BY ENVIRONMENTAL	)	
SURCHARGE	)	

KENTUCKY UTILITIES COMPANY

SUPPLEMENTAL RESPONSE TO THE COMMISSION STAFF'S FIRST INFORMATION REQUEST

DATED JULY 12, 2011

FILED: AUGUST 9, 2011

KENTUCKY UTILITIES COMPANY

Supplemental Response to the Commission Staff's First Information Request Dated July 12, 2011

Supplemental Response filed August 9, 2011

Case No. 2011-00161

Question No. 39

Witness: Gary H. Revlett

Q-39. Refer to Direct Testimony of Gary H. Revlett ("Revlett Testimony"). Did KU or any of the PPL affiliated entities file comments on the May 3, 2011 version of EPA's HAPs proposed rule? If so, provide a copy of the comments.

A-39. **Original Response:**

While the due date for the comment period for EPA's proposed HAPs rule was extended to August 4, 2011, the date at which they will issue the final rule remains November 16, 2011. Comments for this rulemaking will be provided under a joint effort among all PPL entities to EPA by the August 4, 2011 due date. Upon completion and submittal, a copy will be provided to the KPSC.

Supplemental Response:

Please see the attached comments on the proposed HAPs Rule filed with the EPA on August 4, 2011, on behalf of all PPL entities.

Reid T.Clemmer, P.E.
Corporate Environmental Policy
and Strategy Manager

PPL Services Corp.
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Submitted via email and Electronic Submission to www.regulations.gov

August 4, 2011

EPA Docket Center, EPA (EPA/DC)
Environmental Protection Agency, Mailcode: 2822T
1200 Pennsylvania Avenue, NW
Washington, DC 20460
Attention: Docket ID No. EPA-HQ-OAR-2009-0234 and EPA-HQ-OAR-2011-0044

Comments of PPL Corporation on the Proposed National Emission Standards for Hazardous Air Pollutants from Coal and Oil-Fired Electric Steam Generating Units and the Proposed Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units 76 Fed. Reg. 24976 (May 3, 2011)

Docket Nos. EPA-HQ-OAR-2009-0234 and EPA-HQ-OAR-2011-0044

To Whom It May Concern:

PPL Corporation (hereinafter "PPL") submits these comments on behalf of its wholly owned indirect subsidiaries, PPL Energy Supply, LLC, Louisville Gas and Electric Company, and Kentucky Utilities Company, in response to the U.S. Environmental Protection Agency's proposed rule entitled "National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units," 76 Fed. Reg. 24976 (May 3, 2011) (hereinafter, "Proposed Rule" or "MACT Rule").

PPL is a global energy company that owns or controls merchant and regulated utility power generation assets in three states with a total generating capacity of 19,000 megawatts, including 11 coal-fired power plants in Pennsylvania, Kentucky, and Montana. PPL's regulated utility operations provide electricity to 2.3 million customers in Pennsylvania and Kentucky. PPL fully supports responsible environmental regulation aimed at protecting public health and the environment in a cost-effective manner that also provides appropriate protection for the economic well-being of the states served by PPL. As one of the most far reaching and costly rules ever proposed under the Clean Air Act, the Proposed Rule will have significant impacts on PPL's generating fleet and on the residential, commercial, and industrial customers who ultimately receive electricity from the affected plants. The Proposed MACT Rule has the potential to inflict severe harm on the economies of those states that rely heavily on coal-fired power generation and impose additional hardship on residents of those states who already face challenging economic conditions.

Electricity is the lifeblood of most state economies including the states in which PPL operates. States that generate a substantial portion of their electricity from coal are particularly vulnerable to having that lifeblood jeopardized by this rule. It is critical for EPA to structure the final rule to avoid imposing unnecessary costs on the still-struggling U.S. economy and the economies of the states that rely on coal-fired generation.

The Proposed Rule is among the most complex rulemakings ever undertaken by EPA, covering hundreds of pages of Federal Register text supported by tens of thousands of pages of spreadsheet data, technical analysis, emission calculations, regulatory impact data, and legal and policy rationales. It is critical for the final rule to incorporate clear and appropriate regulatory standards fully supported by technically sound data analysis. We urge EPA to give careful consideration to the comments of PPL and others prior to promulgating a final rule in order to correct significant flaws in the Proposed Rule and avoid unnecessary impacts on the power generation industry, states that rely on coal-fired generation of electricity, and their electricity consumers.

If you have any questions, please feel free to contact me at 610-774-5475 or rtclemmer@pplweb.com.

Sincerely,

Reid T. Clemmer

Reid T. Clemmer, P.E.
Corporate Environmental Policy and Strategy Manager

Comments of PPL Corporation
on the

Proposed National Emission Standards for Hazardous Air Pollutants from Coal and Oil-Fired Electric Steam Generating Units
and the

Proposed Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units

76 Fed. Reg. 24976 (May 3, 2011)

Submitted to the
The United States Environmental Protection Agency

Docket Nos. EPA-HQ-OAR-2009-0234 and EPA-HQ-OAR-2011-0044

August 4, 2011

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Electricity is the lifeblood of most state economies including the states in which PPL operates. States that generate a substantial portion of their electricity from coal are particularly vulnerable to having that lifeblood jeopardized by this rule. For example, in states such as Kentucky, low-cost electricity is the primary competitive advantage in attracting and retaining large manufacturing operations. Kentucky successfully encouraged companies such as Ford and Toyota to build and operate large automotive plants in part due to the low cost of electricity. America's largest fully integrated steel producer is located in Kentucky largely for this reason. Chemical, paper, and various types of manufacturing operations are also located in Kentucky. Each consumes significant amounts of electricity, creates thousands of substantial jobs, and competes for business in the global economy. The MACT Rule may eliminate Kentucky's economic advantage, creating more poverty in a state that already ranks as one of the poorest in the country and even higher levels of dependency on government entitlements. It is critical for EPA to structure the final rule to avoid imposing unnecessary costs on the still-struggling U.S. economy and the economies of the states that rely on coal-fired generation.

The Proposed Rule is among the most complex rulemakings ever undertaken by EPA, covering hundreds of pages of Federal Register text supported by tens of thousands of pages of spreadsheet data, technical analysis, emission calculations, regulatory impact data, and legal and policy rationales. It is critical for the final rule to incorporate clear and appropriate regulatory standards fully supported by technically sound data analysis. We urge EPA to give careful consideration to the comments of PPL and others prior to promulgating a final rule in order to correct significant flaws in the Proposed Rule and avoid unnecessary impacts on the power generation industry, states that rely on coal-fired generation of electricity, and their electricity consumers.

A. General Comments Regarding the National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-Fired Electric Utility Steam Generating Units Portion of the Proposal

1. EPA has not justified the regulation of non-mercury hazardous air pollutants.

EPA should reconsider its determination that regulation of non-mercury hazardous air pollutants (HAPs) is appropriate and necessary within the meaning of Section 112 (n)(1)(A) of the Clean Air Act. EPA has adopted an overly expansive interpretation of "appropriate and necessary" that, among other deficiencies, does not fully acknowledge the special statutory framework applicable to electric generating units (EGUs), ignores the costs of regulating non-mercury HAPs in its beyond-the-floor analysis, and fails to consider reductions that will otherwise be achieved through implementation of all relevant Clean Air Act requirements. Moreover, EPA's new determination flatly contradicts its 1998 Report to Congress in which the agency concluded that only mercury emissions from coal-fired power plants and possibly nickel emissions from oil-fired units pose potential health concerns. The discussion of health effects in Section XII A of the Preamble to the Proposed Rule (76 Fed. Reg. 25079 - 25083) reinforces

EPA's previous determination that only regulation of mercury is justified. Although EPA previously identified possible concerns regarding nickel emissions from oil-fired generating units, the risks posed by such emissions are low and EPA has provided no justification that regulation of such emissions is appropriate and necessary. Section 112(n)(1)(A) requires EPA to make an affirmative health-based determination for regulation of utility HAPs. At a minimum, EPA should provide a point by point review of its 1998 report and a detailed explanation of the basis for EPA reaching a different conclusion regarding regulation of non-mercury HAPs in the current rulemaking.

2. The proposed total particulate matter limit for existing sources is excessively stringent.

The proposed total particulate matter (PM) limit for existing sources is overly stringent in that it requires compliance during startup and shutdown events without providing any margin for the higher emissions that unavoidably occur during those periods. EPA ignores the fact that emission controls are not generally capable of achieving steady state operation during those periods and in many cases operation of controls would contravene the directions of equipment manufacturers. EPA fails to explain exactly how startup and shutdown conditions were considered in setting the proposed limit. The test data (i.e., Parts II and III of the 2010 Information Collection Request (ICR)[OMB Control No. 2060-0631]) that support the proposed PM limit reflect a "snapshot" taken during continuous operation, rather than data representative of startup and shutdown periods. EPA suggests that adoption of a 30-day emission limit provides sufficient flexibility to account for startup and shutdown events which EPA believes to be infrequent and predictable. 76 Fed. Reg. at 25028. However, based on its own operational experience, PPL points out that both of these assumptions are incorrect, particularly for merchant plants that must frequently ramp load up and down as required by directives from the independent system operator and purchaser requirements under the terms of commercial power sales agreements. In the future, the frequency of startups and shutdowns for fossil-fired generation is expected to increase as renewable energy generation with more intermittent availability is added to the grid.

Significantly, EPA recognized in its recent Industrial Boiler MACT rulemaking that higher emissions are unavoidable during startup and shutdown. In that rulemaking, EPA excluded startup and shutdown periods from compliance with specified limits and simply required the sources to implement specified work practice standards during those periods. There is no reason to take a more stringent approach with this rule. If EPA insists on applying the PM standard to startup and shutdown periods, it should adopt a separate work practice standard applicable to such periods in lieu of an emission limit. Any work practice standards should be specific to a unit's boiler type and control equipment.

In addition, EPA erred in adopting a total PM limit as a surrogate for non-mercury metallic HAPs, rather than a filterable PM limit. Studies of the 2010 ICR data by the Electric Power Research Institute (EPRI) have identified a closer correlation between filterable PM and non-mercury metallic HAPs. Total PM includes condensable particulate matter (CPM) whose inclusion some contend is necessary to improve the surrogacy relationship between selenium and a PM surrogate. However, EPRI's analysis of the 2010 ICR data (which will be submitted to the docket by EPRI) indicates that selenium emissions do not correlate well with measured CPM emissions, leading to the conclusion that selenium has a stronger relationship with filterable particulate matter. Additionally, there is a concern regarding the amount of selenium that is actually captured and measurable by the available CPM test method (i.e., EPA Method 202).

Again, EPA took a different approach in the recent Industrial Boiler MACT rule, adopting only a filterable PM limit. There is no reason to take a different approach in this rulemaking.

3. The proposed mercury and particulate matter limits for new sources are so stringent that they may effectively preclude permitting of new coal-fired units.

The proposed mercury and particulate matter limits for new sources are extremely stringent – one to two orders of magnitude more stringent than the standards for existing sources. Based on PPL's experience in engineering and permitting its most recent unit, the proposed limits may effectively preclude permitting of new coal-fired units. The newest and cleanest coal-fired generating unit in the PPL fleet is Trimble County Unit 2 which is operated by PPL's indirect subsidiary, Louisville Gas and Electric Company. Trimble County Unit 2, which commenced commercial operation in 2011, has one of the most extensive emission control trains of any current coal-fired generating unit – wet flue gas desulfurization (WFGD), selective catalytic reduction (SCR), wet electrostatic precipitator (WESP), dry electrostatic precipitator (DESP), fabric filter baghouse, activated carbon injection (ACI), and dry sorbent (hydrated lime) injection technologies. In a 2009 permit revision, the state agency incorporated mercury emission limits ($13x10^{-6}$ lb/MWH on a 12-month rolling average) in the permit for purposes of compliance with the unit-by-unit MACT approach EPA was undertaking pending revision of its Clean Air Mercury Rule.

The Proposed Rule's limit for total PM of 0.050 lb/MWH (approximately 0.005 lb/MMBtu) is more than three times lower than Trimble County Unit 2's permit limit of 0.018 lb/MMBtu. There is serious question as to whether a new facility with even the extensive emission control train of Trimble County Unit 2 could comply with the proposed total PM limit on a consistent basis. The proposed mercury limit of 0.0002 lb/GWH[1] is more than sixty times lower than Trimble County Unit 2's permit limit of 0.013 lb/GWH. A new facility with a control train on par with Trimble County Unit 2 would find it virtually impossible to meet the proposed mercury limit for new sources on a consistent basis. Due to the levels of sulfur, chlorine, and mercury typically found in most coals, it would generally be necessary to achieve emission control efficiencies in the range of 99.6% to 99.99% or greater in order to assure continuous compliance with the proposed limits. There are no currently available control technologies capable of consistently achieving those efficiencies. The proposed mercury limit could possibly be met by a limited number of new facilities whose owners might identify atypical coal seams meeting highly specific fuel box parameters compatible with control efficiencies of current technologies. However, such atypical coal supplies would be unavailable to the vast majority of new facilities. Consequently, from a practical standpoint, the proposed mercury limit is unachievable on an industry-wide basis.

In light of EPA's recent MACT determination for Trimble County Unit 2, PPL suggests that the PM and mercury limits for new sources should be no more stringent than the permit limits for Trimble County Unit 2 – one of the best controlled generating units in the country which has only recently commenced operation. Establishing standards applicable to pulverized coal (PC) boilers based on levels achieved at fluidized bed combustion (FBC) units is entirely inappropriate. FBC units and PC boilers employee such significantly different combustion processes that they should be in separate categories. See discussion within comment A(5) below.

4. EPA has proposed limits based on a flawed MACT analysis.

[1] In response to a May 6, 2011 letter from the Utility Air Regulatory Group, EPA has posted on its website a notice that the proposed mercury limit for new sources has been changed to 0.0002 lb/GWH from 0.000010 lb/GWH in order to address a conversion error by EPA.

In determining the MACT floor based on the average performance of the top 12% of existing sources as required by Section 112, EPA should consider the top 12% of the entire source category or subcategory. EPA utilized that approach in setting the proposed hydrogen chloride (HCl) and PM limits using emissions data from 131 units (12% of the 1091 coal-fired units). However, in setting the proposed mercury limits, EPA only considered the top 12% of the units for which it had emissions data (representing only 40 units). EPA's 2010 ICR request – the source of the data primarily relied upon by EPA in setting the standard – required stack testing of the best performing units. While EPA supplemented the stack testing data from Part III of the 2010 ICR with additional historic test data from Part II of the 2010 ICR, EPA did not closely scrutinize the quality of that data. The end result is that the data for the top 12% of existing sources was skewed toward potentially better performing units. In adopting a final mercury limit, EPA should reconsider data from the top 12% of the entire source category or subcategory.

Moreover, there is a fundamental flaw in EPA's analysis that undermines the entire technical foundation supporting EPA's MACT floor determination. The agency has essentially "cherry-picked" the best performing sources on a pollutant-by-pollutant basis without regard for overall performance of the source and effectiveness of emission controls for all specified HAPs. In setting MACT limits, EPA identifies the top performing sources for one pollutant and the top performing sources for another pollutant, but ignores the fact that the same facilities are not generally found in both groups. In reality, the fuel types, boiler configurations and control technologies that result in the lowest mercury emissions differ from those that result in the lowest HCl emissions.

As an example, FBC units and PC boilers employ fundamentally different types of combustion processes. FBC units typically operate at lower furnace temperatures, burn larger size coal particles, employ longer residence times in the combustion process, and typically have higher levels of unburned carbon (less efficient use of the coal) present in the flue gas stream which may assist in increasing mercury capture. PC units pulverize the coal to a very fine particle size to maximize combustion efficiency and thus minimize unburned carbon levels. Of the 40 units EPA selected from the 2010 ICR data to form the basis of the mercury MACT floor analysis for existing units designed to fire coal >8300 BTU/lb, 14 were FBC units (about 35% of the MACT floor pool). Yet only about six percent of the total industry population is made up of FBC units.

EPA's disjointed MACT analysis results in artificially low MACT emission limits that may only be met by an imaginary "Franken-plant" that may not exist in the real world. Because this analysis ignores what is achieved by an actual, best-performing unit (or best performing 12% of sources) it is fundamentally inconsistent with the basic tenets of Section 112.

To the extent that EPA proposes emission standards that are above the MACT floor, the agency is required to conduct a cost-benefit analysis to demonstrate the appropriateness of such standards. In the present instance, EPA's cost-benefit analysis dramatically underestimates the cost of compliance. For example, PPL's indirect subsidiaries, Louisville Gas and Electric Company and Kentucky Utilities Company made filings with the Kentucky Public Service Commission on June 1, 2011, to obtain approval to undertake over $1.7 billion in retrofits to comply with the MACT Rule. [2] These and other capital expenditures for environmental

[2] *In the Matter of: Application of Kentucky Utilities Company for Certificates of Public Convenience and Necessity and Approval of Its 2011 Compliance Plan for Recovery by Environmental Surcharge*, KPSC Case No. 2011-00161, Application of Kentucky Utilities Company (filed June 1, 2011); *In the Matter of: Application of Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Approval of Its 2011 Compliance Plan*

compliance facilities and their associated ongoing operations and maintenance costs (projected to be $90 million in 2016) will result in a 12.2% rate increase for KU customers and a 19.2% rate increase for LG&E customers by 2016. Those increases do not take into account the costs associated with retiring generating units with a current book value of over $100 million—units the MACT Rule will make uneconomical to run beginning in 2016—nor do they account for the additional cost of replacing the retired units. With cost impacts of this magnitude for a combined utility system with less than 8,000 MW of coal-fired capacity, it is apparent that EPA's cost-benefit analysis (estimating a nation-wide cost impact in 2016 of less than $11 billion) has failed to account for significant costs of compliance.

Moreover, for states like Kentucky, one of whose competitive advantages has been low-cost electricity, rate increases of these magnitudes could have serious economic consequences other than the immediate cost of increased rates. Kentucky is home to a number of high-electricity-use industrial facilities, including Ford, Toyota and General Electric. The electricity cost increases resulting from implementation of the MACT Rule could drive such employers out of the state, or at least cause them to consider expanding their operations elsewhere (and perhaps overseas rather than elsewhere in the United States). It is not clear that EPA has attempted to account for such costs in its analysis.

Finally, EPA's cost-benefit analysis is further flawed because it double-counts benefits purportedly resulting from reductions in PM 2.5 emissions under the Proposed Rule. The PM 2.5 reductions and associated health benefits that EPA points to as the primary benefit of the MACT Rule will occur regardless of whether a MACT Rule is promulgated because such PM 2.5 reductions are mandated by other regulatory requirements including the Cross-State Air

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for Recovery by Environmental Surcharge, KPSC Case No. 2011-00162, Application of Louisville Gas and Electric Company (filed June 1, 2011)

Pollution Rule, National Ambient Air Quality Standards, and regional haze requirements. A thorough and unbiased cost-benefit analysis is critical in order for EPA to reach the appropriate balance between protection of public health and the environment and avoidance of unnecessary costs that burden the economy while providing little or no environmental benefit. We request that EPA conduct a new cost-benefit analysis that corrects the serious flaws in its previous analysis.

5. EPA has proposed limited subcategories that do not reflect key difference in emissions among various generating units.

In the Proposed Rule, EPA establishes limited categories and subcategories that fail to reflect the differences between various generating units and the corresponding differences in the nature of emissions and the technical feasibility of applying emission controls. Specifically, in the Proposed Rule EPA provides for eight subcategories based on fuel type (>8,300 Btu coal, <8,300 Btu coal, gasified coal, and solid oil-derived fuel) and unit vintage (existing or new). For comparison, in the recent Industrial Boiler MACT Rule, EPA has specified four fuel subcategories and six boiler subcategories, along with vintage (existing or new) that result in 18 separate emission limits for various types of facilities covered by the rule. EPA's subcategories in the Proposed Rule fall far short of that mark. EPA states that it has considered additional subcategories in the present rulemaking, but suggests that the agency could find no significant difference in emissions among potential subcategories that would warrant subcategories. However, the agency has overlooked a number of key parameters that suggest additional subcategories.

In order to fully account for the differences among fossil-fired generating units and identify appropriate limits that are achievable through currently existing technologies, EPA should establish additional subcategories. In setting the mercury limit, EPA should further subcategorize by boiler type (pulverized coal and fluidized bed). The same example used in comment A(4) above demonstrates the large differences in PC boilers and FBC units. The following table shows information regarding difference in emissions from these boiler types using the available 2010 ICR data.

MERCURY				
Boiler Type	Total Count in 2010 ICR Data Set	Mean (lb/MMBtu)	Standard Deviation (lb/MMBtu)	Average of Top 12 % (lb/MMBtu)
FBC (all coals)	31	1.3×10^{-6}	2.9×10^{-6}	8.5×10^{-9}
FBC (without lignite)	26	3.8×10^{-7}	6.4×10^{-7}	7.4×10^{-9}
PC (all coals)	302	3.1×10^{-6}	3.5×10^{-6}	2.8×10^{-8}
PC (without lignite)	296	3.0×10^{-6}	3.5×10^{-6}	2.8×10^{-8}
All boiler types	339	2.9×10^{-6}	3.5×10^{-6}	2.1×10^{-8}

Unless EPA establishes more appropriate subcategories in the MACT Rule, companies will be forced to comply with "one size fits all" limits which greatly increase the difficulty of compliance on an industry-wide basis.

6. The emissions averaging provisions should be clarified.

EPA proposes that existing sources may demonstrate compliance through emissions averaging of units at an affected source that are within a single source subcategory. This is a very useful compliance mechanism that could potentially provide a source with much needed flexibility. However, the emissions averaging provisions are complex and ambiguous as currently proposed and may ultimately make them impracticable. In order for unit averaging to be a meaningful option, EPA must clarify these ambiguities and explain exactly how the provision must be implemented. For example, it is unclear how to account for units which are shutdown for an outage or whether individual unit baseline testing is necessary. See technical comments C(22)-C(24) below for several other examples of required clarifications.

In response to EPA's request for comment, PPL does not support application of a discount factor for units using emissions averaging. Imposition of a discount factor effectively lowers the allowable emissions for those sources without any justification. A discount factor is unnecessary because the Proposed Rule incorporates a number of other safety factors that obviate the need for such potential protection.

7. Some work practice standards require clarification and revision.

EPA needs to clarify what constitutes optimization of controls. For example, would this require operation of all available scrubber vessels or all precipitator sections even if not needed to meet permit limits?

In addition, work practice standards for optimizing both NO_x and CO emissions appear somewhat contradictory since the actions taken to reduce one value will generally increase the other value. The Proposed Rule provides no guidance as to EPA's expectations on the proper balance necessary to achieve such "optimization." At a minimum, EPA should explain the specific testing and documentation necessary to demonstrate optimization. Of further note, the required frequency for boiler tune ups does not reflect standard industry operational practices. It is not unusual for facilities to have scheduled major outages (i.e., outages of sufficient length to conduct a "boiler tune-up") at a frequency of every three to four years. Consequently, the required boiler tune-up frequency should be no less than every four years to reflect common industry operational practices.

Because power generation boilers operation requires continuous monitoring as described below, we recommend that work practice standards are not needed for boiler tune-ups and that EPA should remove this requirement. Power generation boilers often do not have annual outages and run for three to five year periods. Some boilers operate under pressure requiring that burner monitoring be done remotely with instrumentation. Even power generation boilers that are not pressurized have such intense flames that direct observation has to be supplemented by instrumentation. A power generation boiler typically has a feedback combustion control system that performs "tune-ups" continuously by monitoring temperature and residual oxygen levels and distribution in the exhaust gases. To supplement the automatic controls the boilers are monitored continuously by operators. Burner operation and combustion are monitored by the operators on shift rounds. Detailed visual burner inspections are done when the boiler is in operation. The inspections consist of visual inspection for plugging, damage, flame shape, and alignment. Suspicious flame patterns are investigated. Coal injection nozzles can be remotely moved and air dampers moved to control flame shape. Faults would show up in a loss of production efficiency, so there is substantial incentive to maintain the combustion equipment. During the major outages, every three to five years, equipment is subject to detailed inspections and faults are corrected. For these reasons, EPA's proposed requirement for boiler tune-up work practices is inappropriate for power generation boilers and should be removed from the Proposed Rule.

In the alternative, EPA should at a minimum allow sources to petition EPA for approval of work practice standards that do not meet the specified criteria, but do meet an objective of proper boiler operation.

8. Monitoring and reporting requirements should maximize efficiency and avoid redundancy.

The data gathering requirements in the Proposed Rule are extremely difficult due to the lack of approved test methods, data variability, and short deadlines for testing. At a minimum, EPA should adjust the deadlines and frequency for data gathering to take these factors into consideration. Extending the testing frequencies to at least a quarterly basis (instead of monthly or every other month) would allow more substantial analysis of gathered data and reduce potential burdens resulting from more frequent laboratory analysis and test report submittals.

PPL has additional concerns regarding data reporting. The requirement for using the Electronic Reporting Tool (ERT) for submittal of emission test results greatly increases the burden on sources, easily adding 10% to 20% to the cost of compliance due to the time needed to manually input significant amounts of information. Manually inputting data significantly increases the potential for errors in data reporting. If EPA mandates use of ERT for submittal of test results, it is important for the agency to make this tool more user-friendly to facilitate such use. In addition, a source should not be required to make paper or other electronic submittals of the same data submitted through ERT, but should only be required to reference data previously submitted.

PPL supports the elimination of bias test and data substitution for HAP monitors. Because these monitors are not used for purposes of a cap and trade program, bias and data substitution provisions are unnecessary (Preamble Section IV. L – Discussion of Specific QA/QC Procedures). PPL supports EPA's proposed approach to streamline the continuous compliance requirements for monitoring, reporting, and recordkeeping (See Preamble Section IV. J). EPA is correct in recognizing that the compliance requirements are already applicable to EGUs and eliminating redundancy wherever possible. PPL urges EPA to remain open to additional accommodations that are identified in the course of implementing the program.

9. The parametric monitoring requirements should ensure correlation to HAP emissions.

The provisions for establishing parametric monitoring for future operations are inflexible and inappropriate. Once testing is completed, parameters are established based on this one time "snap shot" regardless of any correlation with HAP emissions. In order for parametric monitoring to serve any meaningful purpose, the Proposed Rule must provide for a mechanism for ensuring that the selected operational parameters correlate with actual HAP emissions. The control device operating parameters identified in the Proposed Rule do not necessarily have a direct relationship to emissions. For example, scrubber pressure drop and liquid flow rate are usually a function of boiler load. Thus operational levels above or below those recorded during a performance test are not necessarily indicative of emission levels during those events. As unit load varies, scrubber pressure drop will also vary (especially during start-ups, shutdowns and malfunctions), but may not indicate a change in a scrubber's performance in meeting an emission limit. Although EPA's provision for a 10 percent allowance in the determination of the operational limit may recognize some of this operational variability, it is not sufficient in most circumstances. Without a clear correlation between the operating parameters and the applicable emission limit, imposition of those values as enforceable limits would unreasonably restrict source and control device operation and subject sources to potential enforcement without any evidence that an emission limit was violated. At the minimum, PPL proposes that sources be given the opportunity to work with the appropriate permitting authority to develop site-specific parameters for wet scrubbers that are adequate to ensure compliance, while also providing operational flexibility to the sources.

For sources electing to use continuous emissions monitoring systems (CEMS), parametric monitoring is inappropriate. If a source demonstrates compliance through CEMS data, it is implicit that the source has undertaken operational practices sufficient for compliance. Conversely, if the CEMS demonstrates noncompliance, parametric monitoring cannot establish the opposite. In such an instance, parametric monitoring is an extra step that provides no environmental benefit or other value. Such requirements only serve to complicate source record keeping and reporting requirements and increase burdens not only on the source owner/operator, but also on the states that must review and otherwise address all the additional data.

10. EPA should provide for a one-year blanket extension of the compliance deadline.

Because the Proposed Rule requires compliance on a unit-by-unit basis, it will require construction of large numbers of FGD, baghouse, and ACI retrofits on a nation-wide basis. In the Administrator's announcement of a four-year compliance period, EPA appears to recognize the physical impossibility of completing emission control retrofits of that scale and magnitude (and the planning, engineering, permitting, procurement, and construction activities that accompany them) within the three-year statutory timeframe and assumes that one-year extensions will be liberally granted on a case-by-case basis by the states pursuant to Section 112(i)(3)(B). Even a four-year compliance period is extremely aggressive for control retrofits required by the Proposed Rule. To meet even a four-year compliance deadline, many companies will find it necessary to complete their project planning efforts as soon as possible and commence construction on an expedited schedule. For example, PPL's indirect subsidiaries, Louisville Gas and Electric Company and Kentucky Utilities Company, made filings with the Kentucky Public Service Commission on June 1, 2011 as necessary to obtain approval to undertake over $1.7 billion in retrofits for compliance with the MACT Rule.

Relying on the states to grant one-year extensions on a case-by-case basis will not provide companies with compliance extensions within a timeframe that is compatible with the expedited schedule necessary to complete the required retrofits. Instead, it will place most companies in the difficult position of needing to commence retrofit projects without any assurance of a firm four-year compliance deadline. It is simply unreasonable and unworkable to expect companies to commence retrofit projects costing billions of dollars based on the mere expectation that a one-year compliance deadline will be granted. In the event that a utility commenced fleet-wide retrofit projects based on the expectation of a one-year extension, but the extension request was ultimately denied by the state, the utility and its customers could potentially face dire consequences. Therefore, PPL urges EPA to grant a blanket one-year extension, in lieu of case-by-case extensions, in order to ensure the timely compliance extension and appropriate compliance deadline that are critical for compliance planning purposes.

11. EPA should adopt the term "oil-affected units" to address oil-fired and oil and gas fired units that have low capacity factors on oil fuel usage.

The Proposed Rule adopts the definition of "oil-fired" unit contained in the Acid Rain Program in 40 C.F.R. § 72.2. *See* 76 Fed. Reg. at 25,020. In the Proposed Rule, the definition determines whether a unit that combusts oil is an affected unit based on the percentage of oil combusted by the unit compared to its total heat input. PPL does not believe that this is an appropriate means for differentiating between affected and non-affected oil-fired units because it is likely to subject low capacity units to regulation, regardless of whether such units have significant HAP emissions from the combustion of oil. Instead of using the Acid Rain Program's definition of oil-fired unit, EPA should adopt a new definition -- "Oil-Affected Unit" -- that differentiates between affected and non-affected units based on the total quantity of oil combusted.

The principal goal of the Proposed Rule is to reduce emissions from oil used for electric generation. The most effective means for achieving these reductions is to target units that combust more than insignificant quantities of oil. The Proposed Rule would exclude from regulation EGUs that did not fire "oil for more than 10.0 percent of the average annual heat input during the previous 3 calendar years or for more than 15.0 percent of the annual heat input during any one of those calendar years." 76 Fed. Reg. at 25,102 (proposed 40 C.F.R. § 63.9983(c)). Because the exclusion is based on a fuel combustion ratio, a unit that operates for only two days (one on oil, one on gas) could be subject to the Proposed Rule, and a unit that combusts the same quantity of oil as the first unit but operates for multiple days on gas to be excluded. Such an arbitrary result is possible given the current operating practices for oil and oil/gas units. Since the promulgation of the Acid Rain Program regulations in 1993, the operation of oil and oil/gas fired units has changed significantly. A large fraction of these units are no longer base load units, and typically operate at capacity factors well below 50 percent. In many cases, the capacity factor is less than 15 percent. The EIA Annual Energy Outlook 2011 forecasts that the amount of liquid fuels used for electricity generation in 2015 will be approximately 60 percent lower than 2000 levels.

PPL urges EPA to revise the Proposed Rule to define an oil-affected unit (an oil-fired unit that is subject to the EGU MACT rule) as a unit that had a three-year average oil heat input greater than 10 percent of the maximum potential annual heat input, calculated by multiplying the maximum design heat input by 8760. This definition would ensure that the EGU MACT rule targets EGUs with greater HAP emissions from the combustion of oil, and address EPA's concerns regarding limited use oil-fired units, which typically operate at very low capacity factors.

12. The standards should be revised to provide increased compliance flexibility.

EPA should allow sources to calculate and comply with pound per hour (lb/ hour) MACT standards determined to be equivalent to lb/MMBtu MACT standards at maximum capacity, thereby allowing sources to reduce load to lower the lb/hour emissions to comply with these MACT standards. See preamble Section IV.G - Emission Limits.

Output standards should be based upon gross output. Otherwise generating units with substantial parasitic load needed to run emission control equipment would be unduly penalized. Gross output is the best parameter for output-based standards because it is the best representation of unit performance. Any standards adopted in this rulemaking should be tailored toward HAP emissions, rather than considerations such as energy efficiency which fall outside the scope of Section 112. See Preamble Section VII. E. - Standards.

Furthermore, EPA should establish MACT standards based on annual averages. Annual averaging would be consistent with other EPA rulemakings for EGU's (i.e., Acid Rain Program). EPA has not demonstrated why a 30-day average would be more protective for human health than an annual period, particularly for mercury emissions. As mass emissions is the key issue for these HAPs, use of an arbitrary and short averaging period (i.e., 30-day rolling average) does not allow enough operational flexibility to address process issues or startup and shutdown events that may impact compliance.

The data set used to establish the Proposed Rule's MACT standards (i.e., the 2010 ICR data) was solely determined by full load steady-state testing taken at a single point in time and did not encompass the full range of operating conditions including changes in operating variables (i.e., pulverizers taken out of service, fuel variability causing changes in control equipment operations, etc.) that a unit experiences in the normal course of operation. EPA can alleviate some of the effect of variability on unit emissions that was not accounted for in the 2010 ICR testing by allowing annual averaging, while still achieving the same emission reductions. PPL encourages EPA to move the averaging compliance time to an annual period to more adequately address variability that was not captured in the steady-state full load ICR testing as well as providing sources with greater operational flexibility, while still maintaining the same overall reduction in HAPs emissions.

13. EPA Should Revise the Continuous Compliance Demonstration Requirements.

It is not clear in the Proposed Rule that installing and operating CEMS for the regulated HAPs and surrogates will relieve a source of the burden of also monitoring compliance with operating limits on control equipment based on a performance stack test. EPA should require no proof of compliance beyond a properly calibrated and installed CEMS, and EPA should revise both the language and tables in the rule to clarify its intent as it relates to CEMS used for demonstrating compliance.

Currently, HCl CEMS are not commercially available or adequate for in-stack measurements from electric utility units and likely will not be available by the compliance date of the rule. Sources will be forced to either take a fuel limit or an operating parameter limit. The fuel analysis limit is impractical as it relates to a coal-fired facility because of chlorine variability that is inherent in coal. It will be impossible to control fuel deliveries in such a manner as to eliminate the possibility of burning coal with chlorine content above that which was used during compliance testing.

Operating limits for control equipment based on a point-in-time stack test does not recognize the inherent variability of fuel or the balancing act that plant operators perform daily to meet emission limits for, not just HAPs, but all of the pollutants that are currently regulated. As currently proposed, units would be constrained by unachievable operational parameters because the set of operating limits that a unit measures during its first performance test would be its maximum operating limits. Subsequent performance tests would further ratchet down operating parameters until they are no longer achievable during a 30-day or annual averaging period.

Control equipment operating characteristics during full load testing will not be suitable to monitor low load performance. Operating limits based on a compliance test will only be applicable when the unit is running at that most efficient load. If those operating limits begin changing every month or two months based on monthly or every two month performance testing, sources will have no assurance that they will be able to demonstrate compliance over the normal full range of operating conditions for the source. Permitting authorities will also have an impossible task to track different sets of operating limits for each unit in their jurisdiction. Table 7 of the Proposed Rule should be revised to allow a source to work with its permitting authority to develop a compliance plan for PM (or non-mercury HAPS) that reflects what is currently contained in its Compliance Assurance Monitoring plans. A similar plan could be developed to assure compliance with the HCl limits. This approach would recognize that individual sources are in the best position to determine the parameters that should be monitored and controlled to ensure and verify compliance.

Performance testing for those sources without CEMS is cumbersome and expensive. For load-following, peaking and low capacity factor units, frequent performance testing could require operation of the unit which would not otherwise be operated. Testing should be performed annually for each of the stacks instead of monthly or every other month as currently proposed. The proposed source testing requirements will burden testing contractors and it may not be feasible to complete testing at all units within a monthly or two-month period due to lack of test crews, unit scheduling, scheduled maintenance, and other considerations. EPA's assertion that most units will choose to install CEMS may be incorrect based on the current lack of HCl CEMS technology and the relative infancy of PM CEMS technology. The CEMS systems may also be inadequate to measure emissions as low as EPA has proposed under this rule. EPA should reconsider the frequency and types of monitoring appropriate for various subcategories, providing an exemption for low capacity factor and LEE units.

14. The emissions averaging provisions should be applied on a mass emission basis.

While we support EPA's attempt to afford some flexibility in meeting the MACT limits through emissions averaging, we request that EPA provide a mechanism in the final rule for a mass-based emissions average at individual facilities, including adjacent facilities under common control. The proposed emission rate averaging plan does not provide much flexibility because the emission rate limits are so low. In order for a source to take advantage of these provisions, at least one unit would need to achieve a rate substantially lower than the MACT limit. There is no evidence that such rates are achievable for any existing units. A mass-based approach that applies the final MACT emission rate limits to the design heat input for all sources present at a facility on the date that the rule is finalized would achieve the EPA's objective to reduce HAP emissions, while also providing units a much greater level of flexibility to achieve reductions economically. The mass-based approach would provide each facility with a total annual mass emission limit for HCl, PM, and Hg that could provide flexibility for the source to operate in the most economical way to meet that facility-wide limit. The concerns about the HAPs regulated under this rule focus on their ability to accumulate in the natural environment. Consequently, the total mass that is emitted, rather than the rate that the pollutants enter the environment, goes to the heart of these concerns.

Additionally, the averaging provisions should not be limited to units at a facility, but should be expanded to include adjacent units that have controlled access within a common fence line. Due to many factors, including dates of construction and unit acquisitions, not all units are classified as being at the same facility even though they might share contiguous property inside the same fence line. EPA can provide additional flexibility and cost savings on emission reductions by revising the facility definition to include units within a common fence line.

B. General Comments Regarding the Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units Portion of the Proposal

1. The proposed New Source Performance Standard particulate matter limits for new sources are so stringent that they may effectively preclude permitting of new coal-fired units.

The proposed New Source Performance Standards (NSPS) for particulate matter for new (i.e., constructed, modified or reconstructed after May 3, 2011) sources are extremely stringent. Based on PPL's experience in engineering and permitting its most recent unit, the proposed limits may effectively preclude permitting of new coal-fired units. The newest and cleanest coal-fired generating unit in the PPL fleet is Trimble County Unit 2 which is operated by PPL's indirect subsidiary, Louisville Gas and Electric Company. Trimble County Unit 2, which commenced commercial operation in 2010, has one of the most extensive emission control trains of any current coal-fired generating unit – wet flue gas desulfurization (WFGD), selective catalytic reduction (SCR), wet electrostatic precipitator (WESP), dry electrostatic precipitator (DESP), fabric filter baghouse, activated carbon injection (ACI), and dry sorbent (hydrated lime) injection technologies.

The proposed NSPS limit for total PM of 0.055 lb/MWH (i.e., 0.006 lb/MMBtu) is more than three times lower than Trimble County Unit 2's permit limit of 0.018 lb/MMBtu. There is serious question as to whether a new facility with even the extensive emission control train of Trimble County Unit 2 could comply with the proposed total PM limit on a consistent basis.

In light of EPA's recent MACT determination for Trimble County Unit 2, PPL suggests that the PM limits for new sources should be no more stringent than the permit limits for Trimble County Unit 2 – one of the best controlled generating units in the country which has only recently commenced operation.

2. Use of a Combined NO_x and CO Standard

As mentioned at 76 Fed. Reg. 25061 of the Proposed Rule's preamble, EPA is "co-proposing two options for an amended NO_x emission standard. The options are to (1) establish a combined NO_x plus CO standard for new, reconstructed and modified units; (2) amend the NO_x emission standard for new, modified and reconstructed EGUs. PPL is open to the option of a combined limit. However, it would be preferable for EPA to provide both options and allow the EGU to select the option that it prefers.

3. Use of Net-Energy Output-Based Standards

As mentioned at 76 Fed. Reg. 25070 of the Proposed Rule's preamble, EPA is seeking comment on whether to adopt "net-energy output" based PM, SO_2 and NO_x standards in lieu of "gross-energy output" based PM , SO_2 and NO_x standards. The aim would be to "provide a greater incentive for achieving overall energy efficiency and minimizing parasitic load." PPL does not support limits based on net energy output because, as EPA recognizes in the preamble, net-energy output based standards would "result in (energy) monitoring difficulties and unreasonable monitoring costs". See 76 Fed. Reg. 25070. Those high monitoring costs would be incurred unnecessarily as companies do not need an incentive to minimize parasitic load. Parasitic load is lost revenue and companies will be striving to minimize that in any event.

4. Reduction of Method 9 observations under 40 CFR 60.45(b)(7)

As mentioned at 76 Fed. Reg. 25071 of the Proposed Rule's preamble, EPA is accepting comments regarding potential revisions to the schedule for performing Method 9 visual opacity measurements as required for facilities that have installed PM CEMS as an alternative to COMS. The requirement to perform Method 9 performance tests at certain frequencies should be dependent on the results of the previous measurements. PPL suggests that EPA reduce the frequency of tests based on prior results (e.g., if previous readings were 5% or less, there should be a requirement for annual testing rather than testing every six months as currently written). As further discussed in comment B(5) below, PPL believes that plants that have PM CEMS should not be required to monitor opacity at all. However, if EPA requires opacity monitoring for such plants, at a minimum, EPA should reduce the frequency of performing Method 9 tests. PPL has installed five PM CEMS on facilities subject to these provisions under 40 CFR 60.45(b)(7). The company's experience demonstrates that performance of Method 9 tests are time-intensive and consume facility resources, while providing information of limited value. Reducing testing frequencies would alleviate some of the burden on the facility.

5. Elimination of Opacity Standard when using PM CEMS

As mentioned at 76 Fed. Reg. 25071 of the Proposed Rule's preamble, EPA is accepting comments regarding the "appropriateness of eliminating the opacity standard for owners/operators of 40 CFR Part 60, Subpart D affected facilities using PM CEMS even if they are not complying with the 40 CFR Part 60, Subpart Da PM standard." PPL is very supportive of this possible change. As stated above, PPL has installed five PM CEMS on facilities that are subject to the requirements of 40 CFR Part 60 Subpart D. Eliminating the opacity standard for Subpart D units that install PM CEMS would increase the consistency of requirements applicable to Subpart D and Subpart Da units and eliminate some of the points of confusion between the two sets of regulations. In addition, units utilizing PM CEMS are monitoring the primary pollutant associated with opacity (i.e., particulate matter). This largely eliminates the need to rely on the visual appearance of the plume (i.e., opacity) as a measure.

C. Specific Technical Comments Regarding the National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-Fired Electric Utility Steam Generating Units Portion of the Proposal

1. In reviewing EPA databases populated with data supplied by PPL's indirect subsidiaries, Louisville Gas and Electric Company and Kentucky Utilities Company, in response to EPA's 2010 Information Collection Request, PPL has identified that Ghent Unit 4's (ORIS 1356) acid gas test data was duplicated and renamed/assigned as a test for Green River Unit 4 (ORIS 1357). This duplication is identified as "Submittal ID" **165611** for "Facility ID" **1357** in EPA's databases. Green River Unit 4 performed dioxin/furan testing (Submittal ID **1768**), not acid gas testing. The "MACT Floor Analysis-Coal HG-Revised" spreadsheet posted on EPA's website (www.epa.gov/ttn/atw/utility/utilitypg.html) on May 18, 2011 is one specific location at which this duplication is apparent. The errant data associated with Green River Unit 4 is used in the HF floor analysis within that spreadsheet. EPA should remove the erroneously duplicated data from its databases and evaluate the potential impact the data's removal could have on determination of the proposed emission limits.

2. We request EPA to explain its methodology for converting emission limits from units of "lb/TBtu" to units of "lb/GWH." For the emission limits found in Tables 1 and 2 of the proposed rule, it appears that a unit heat rate of 10 million Btu per megawatt (MMBtu/MW) was used to convert the limits units of measure from "lb/TBtu" to "lb/GWH" for all emissions but mercury. For mercury, it appears that EPA used a unit heat rate of 8.8 mmBtu/MW. It appears that a unit specific heat rate would be the proper way to convert the limit and it is unclear why a different heat rate would be used for different standards.

3. We request EPA to explain why the total non-mercury metal HAPs limits displayed in Tables 1 and 2 do not equal the total of all the individual non-mercury metal HAPs limits displayed in Tables 1 and 2. It would seem that if tests were performed to prove compliance with the total non-mercury metal HAPs limit, the test would determine the individual non-mercury metal HAP levels and then be totaled to obtain the "total non-mercury metal HAPS level".

4. Within the proposed regulatory language (40 CFR 63.10005(d)(3)-(6)), it is stated that if CEMS are going to be used for initial compliance determinations then the average hourly concentrations obtained during the first 30-day operating period will be used "after the monitoring system is certified". We request EPA to clarify when the 30-day operating period begins if the systems are already certified (e.g., current SO_2 or PM CEMS being used for 40 CFR Part 75 and/or 40 CFR Part 60 monitoring programs).

5. Converting the existing coal-fired HCl limit in Table 2 (0.002 lb/MMBtu) to comparable parts per million (ppm) concentrations seems to require the ability to measure HCl levels around or below 1 ppm. We are not aware of any commercially available HCl CEMS that are able to accurately measure emissions at this level.

6. As mentioned in the proposed regulatory language (40 CFR 63.10005(d)(7), we request EPA to describe how a facility would use a continuous parameter monitoring system (CPMS) to demonstrate initial compliance. It is unclear whether this section proposes that correlations are to be established between operating parameters (e.g., pH for those units with wet acid gas scrubbers) and emission levels (e.g., HCl) determined during initial compliance testing.

With that correlation, a facility would presumably then calculate correlated hourly emission concentrations and develop 30-day emission rate averages from that data. Such an approach appears to be a highly inaccurate methodology for determining emission compliance.

7. As seen in the proposed regulatory language (40 CFR 63.10005(e)), there is no mention of beginning to use data obtained during the first 30-day operating period "*after the monitoring system is certified*". This language does appear in similar monitoring system sections (i.e., 40 CFR 63.10005(d)(4)-(6)). There are sorbent trap monitoring system certification requirements (e.g., RATA) mentioned in the proposed "Appendix A to Subpart UUUUU – Hg Monitoring Provisions". Therefore, it seems like data should not be used until the initial certification is completed.

8. Similar to comment C(4) above, if sorbent trap monitoring systems are certified prior to the compliance date, EPA should clarify whether the "30 day operating period" for determining initial compliance begins on the compliance date.

9. Regarding the work practice standard of performing an initial performance tune-up (40 CFR 63.10005(f)), EPA should clarify whether the time frame to accomplish this initial performance tune-up is within 180 days after the compliance date. It may be impossible to perform the initial tune-up within the 180 day window following the compliance date due to the potential outage schedule that the unit may be following depending on when this proposed rule is finalized. As an example, longer outage times are needed to perform burner inspections and clean/repair necessary components (as described in proposed 40 CFR 63.10021(a)(16)(i)). PPL has moved to multi-year major outage schedules (i.e., major being defined as long enough to perform the proposed burner, flame pattern, and air-to-fuel ratio system inspection/work and CO/NO_x optimization work). It is likely that sufficient outage time will not be available within the 180-day initial compliance window to facilitate all of this work on multiple units. One year is a more workable time frame in which to accomplish this work.

10. Within the proposed regulatory language seen in 40 CFR 63.10005(k), the reference to performance test data requirements of "paragraph (l) of this section" does not seem appropriate. The reference to "paragraph (l)" seems to point to "40 CFR 63.10005(l)" which discusses default diluents gas concentrations to be used for calculating emissions during startup and shutdown events. That does not seem pertinent to "performance testing" mentioned in proposed 40 CFR 63.10005(b). EPA should clarify or provide guidance on how these two sections are to be used to aid qualification of low emitting EGU (LEE) status.

11. Within the proposed regulatory language seen in 40 CFR 63.10005(l), it is mentioned that a "default diluents gas concentration value of 10.0 percent O_2 or the corresponding fuel-specific CO_2 concentration" are to be used during periods of startup or shutdown when calculating emissions in units of "lb/MMBtu" or "lb/TBtu". EPA should clarify how to calculate the "corresponding fuel-specific CO_2 concentration."

12. From the proposed regulatory language seen in 40 CFR 63.10006 (a), (b), (d), (h) and (i), there does not seem to be allowance for process improvements. As written, subsequent performance tests must be conducted "during the same compliance test period and under the same process (e.g., fuel) and control device operating conditions". Process improvements discovered after initial compliance testing could potentially allow for the same or better control of emissions yet move the control device operating conditions outside of what was established as the "operating limits" established per Table 4 and 7 of the proposed language. We suggest that the "same process and control device operating conditions" language be removed from these regulatory sections. This would be similar to language proposed in 40 CFR 63.10006 (e), (f), (g), (j), (k), (l), and (m) where testing under those "same conditions" is not required.

13. Within the proposed regulatory language of 40 CFR 63.10006, there does not appear to be an option for reduced HCl performance testing requirements on coal-fired units with non-HCl controlled bypass stacks. PPL's Kentucky Utilities Company E.W. Brown Unit 2 is currently configured to send its emissions to a common wet FGD shared with Unit 1 and 3 at the same facility. The common emissions are then emitted through a common stack. All three units are affected coal-fired units designed to burn greater than 8,300 BTU/lb coal. However, E.W. Brown Unit 2 is also configured and permitted to utilize a bypass stack. Within the proposed language of 40 CFR 63.10010(a)(4), it appears E.W. Brown Unit 2's bypass stack would be required to install similar monitoring systems as the main common stack. But without flue gas desulphurization technology on the bypass stack, it appears that the current 40 CFR Part 75 SO_2 CEMS located on the bypass stack could not be used for compliance determinations as a surrogate for HCl. Furthermore, even if the company desired to install a HCl monitor on the dry stack to monitor emissions, it would still be required to conduct performance testing every month because there apparently is not an option to allow HCl monitoring under 40 CFR 63.10006(i)-(k) to cover a non-HCl controlled unit/stack.

14. EPA should clarify the specific testing (initial and subsequent) and monitoring requirements for a unit similar to E.W. Brown Unit 2 with bypass capability. Specifically, EPA should clarify whether initial testing of the bypass emissions need to be tested within the 180-day timeframe described in the proposed language. Alternatively, setting a firm testing timeframe on bypass stack emissions (especially intermittently used bypass stacks similar to Unit 2) seems overly burdensome. Creating emissions (and incurring costs) by switching a unit into bypass mode that would not otherwise have been used simply in order to perform emission testing appears to create unnecessary burden.

15. Within the proposed regulatory language (40 CFR 63.10006(o)), the ability to decrease the frequency of performance testing from annual (or more frequent) is available if testing shows emissions at or below 50% of the emission limit and if there are "no changes in the operation of the affected source or air pollution control equipment that could increase emissions". EPA should provide clarification on what constitutes "no change" and what information would be needed to successfully pass these criteria. For example, it is unclear whether the "no change" provision applies to the affected unit and is not inclusive of the entire facility.

16. Within the proposed regulatory language (40 CFR 63.10006(r)), it is stated that performance tune-ups must be conducted "according to Section 63.10007". However, as proposed, "Section 63.10007" pertains to performance testing not performance tune-ups. If "performance tune-ups" is the correct term, it appears that "Section 63.10021(a)(16)" would be the more accurate section reference.

17. As seen in the proposed regulatory language (40 CFR 63.10006(t)), submitting reports within a timely manner (e.g., 60 days) is typically not an issue. However, facility testing generally occurs on a less frequent basis. If a facility were to choose the option of monthly testing to comply with portions of this proposed regulations, it may be difficult to get information back from a laboratory (especially if there is a back log caused by multiple analysis needs), get a report from the testing firm, and submit the required information within a 60-day window. Adding to the potential laboratory and test firm back log, the next round of testing will begin in the middle of the process of getting the results of the first test. This continual loop of testing and result submittals seems like an overly burdensome and inefficient requirement.

18. EPA should provide guidance on what should be included in a site-specific test plan as mentioned in proposed regulatory language of 40 CFR 63.10007(a) and referenced to 40 CFR 63.7(c). The development of external quality assurance programs with testing firms and laboratories (especially if multiple testing firms and laboratories are needed) has the potential to become extremely burdensome without clearer guidance.

19. It is stated in the proposed regulatory language (40 CFR 63.10007(c)) that performance tests must be conducted "while burning the type of fuel or mixture of fuels that has the highest content..." EPA should clarify whether reference to "type of fuel" simply means that if bituminous coal is typically burned then bituminous coal is to be used during the test. This section does not appear to require a determination that the highest chlorine (or other constituent) content bituminous coal be used during the test. We suggest a clarification that "special fuels" are not required or expected for the performance test.

20. It is stated in the proposed regulatory language (40 CFR 63.10007(f)) that "(p)erformance tests shall be conducted under such conditions as the EPA Administrator specifies to the owner or operator...." The purpose of this paragraph is uncertain. EPA should clarify whether it will specify when and how performance testing is to be completed, beyond what is already proposed in other sections of the regulatory language. EPA should provide clarification on what criteria would be used to determine the extra conditions. Other sections of the proposed regulatory language specify when, how and under what conditions the performance testing is to be conducted. Therefore, the proposed section 40 CFR 63.10007(f) appears unnecessary and should be removed.

21. EPA should clarify whether the fuel analyses and procedures in the proposed regulatory language (40 CFR 63.10008) are only applicable to liquid oil-fired EGUs that desire to meet their applicable emission limits through fuel sampling.

22. In the proposed regulatory language (40CFR63.10009(c)), it is stated:

> "...the emission rate achieved during the initial compliance test for the HAP being averaged must not exceed the emission level that was being achieved on [THE DATE 30 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE FEDERAL REGISTER] or the control technology employed during the initial compliance test must not be less effective for the HAP being averaged than the control technology employed on...."

EPA should clarify whether this section requires that a "pre-test" be conducted so that a comparison can be made between a "30 day after" value and the initial compliance test. If so, EPA should specify the notification and submittal requirements for such a test. Finally, EPA should clarify what kind of documentation is needed for the "control technology" option to prove that it has not become "less effective."

23. The alternative "emissions averaging" methodologies are somewhat defined in proposed regulatory language section 40 CFR 63.10009. However, clarification is needed in several areas to address the following:

a. How is data averaging handled if one unit does not operate during a 30-day period (i.e., extended outage)? Are zeros allowed to be averaged in or only emissions from the remaining units in the averaging group?

b. All of the equations (Eq.1, 2, 3 and 4) all seem to specify that the emission rates to be used are "determined during the most recent performance test". If CEMS (i.e., PM, HCl or Hg) are being used to determine compliance with the limits, why would values from those monitors not be used?

c. Similarly, if SO_2 data via CEMS is being gathered for comparison with the acid gas alternate SO_2 limit, why couldn't those values not used on a monthly demonstration method for HCl?

d. EPA should provide examples of how this emissions averaging methodology may be effectively used.

24. Within the proposed alternative emission averaging methodology, there are procedures specified to determine an emission limit for units from different subcategories that emit from a common stack (40 CFR 63.10009(j)). Equation 6 states that "Hi = Heat input from unit" should be used to determine the combined/averaging unit emission limit. However, if "Hi" is interpreted to mean the heat input during the performance test, it would effectively put an additional limit (i.e., heat input) on the units. In determining an emission limit, it appears more appropriate to use the units' maximum rated heat input (or capacity) to allow more flexibility in determining the common stack emission limit. EPA should provide the appropriate clarification.

25. Within the proposed regulatory language (40 CFR 63.10010(a)(4)), reference is made to installing "...CEMS and the monitoring systems described in paragraph 2.1 of this section..." This paragraph reference is inaccurate because "paragraph 2.1 of this section" does not exist. Did EPA mean to make reference to section 2.1 of Appendix A, pertaining to Hg monitoring systems? EPA needs to correct this reference.

26. Within the proposed regulatory language (40 CFR 63.10010(b)), reference is made to following Appendix A of this subpart "...in lieu of procedures in paragraphs (a)(1) through (a)(3) below...." The reference to (a)(1) through (a)(3) is inaccurate because they do not pertain to O_2 and CO_2 monitors. EPA likely needs to correct this reference to (b)(1) through (b)(5).

27. Within the proposed regulatory language (40 CFR 63.10010(e)), reference is made to following 40 CFR Part 75 procedures for SO_2 monitors "...in lieu of procedures in paragraphs (g)(1) through (g)(3) of this section with the additional provisions of paragraph (g)(6)". The reference to "(g)(1) through (g)(3)" and "(g)(6)" is inaccurate because they do not pertain to SO_2. EPA likely needs to correct this reference to (e)(1) through (e)(6).

28. Within the proposed regulatory language (40 CFR 63.10010(h)), reference is made to installing CPMS as specified in Table 5 of this subpart. Table 5 addresses stack testing and CEMS. It appears that EPA should have referenced Table 4 or Table 7 instead.

29. Within the proposed regulatory language (40 CFR 63.10011(b)), reference is made to conducting fuel analyses and establishing maximum fuel pollutant input levels "...as applicable". EPA should clarify that the fuel sampling, analyses, and maximum input levels are only applicable to liquid oil-fired EGUs that choose to meet their emission limits through fuel sampling methodologies. The establishment of fuel limits appears applicable only to facilities that choose to comply via fuel analysis. If facilities apply CEMS, accurate compliance can be determined at the emission point and, therefore, the fuel input becomes irrelevant. Additionally, there are numerous inaccurate section/paragraph references within the proposed regulatory language of 40 CFR 63.10011(b). EPA should carefully review this section to properly link references to the appropriate sections and paragraphs.

30. Within the proposed regulatory language (40 CFR 63.10021(a)(2)), reference is made to section 63.10031(c) for keeping records of fuels. Section 63.10031(c) of the proposed regulatory language specifies what is needed within compliance reports and is not related to recordkeeping issues. It appears that EPA should change the reference to 63.10032(d) which outlines what fuel records are to be kept. Additionally, EPA should clarify the frequency of on-going fuel sampling/analysis required for purposes of comparison with "the maximum fuel input values calculated during the last performance tests (if demonstrating compliance through performance stack testing)".

31. Within the proposed regulatory language (40 CFR 63.10021(a)(10)(i)and(ii)), reference is made to continuously monitoring oxygen. Carbon dioxide monitoring as a diluent should be added to this section as an alternative. The following specific language changes are suggested:

a. 63.10021(a)(10)(i): You must continuously monitor oxygen <u>or carbon dioxide</u> according to 63.10010(a) and 63.10020.

b. 62.10021(a)(10)(ii): Keep records of oxygen <u>or carbon dioxide</u> according to 63.10032(b).

32. Within the proposed regulatory language (40 CFR 63.10021(a)(11)(v)), it is stated that all CEMS relative accuracy test audits (RATA) are to be submitted electronically using the Electronic Reporting Tool. EPA should clarify whether this requirement is only applicable to CEMS RATAs performed under the requirements of the proposed rule. EPA should clarify whether only SO_2 RATAs performed for the combined purposes of 40 CFR Part 75 and this proposed regulation would be reported in ERT. Any annual NO_x or Flow monitor RATA performed for 40 CFR Part 75 requirements would <u>not</u> to be reported in the ERT even though it may have been performed concurrently.

33. Within the proposed regulatory language (40 CFR 63.10022(a)(6)), it is stated that existing units with an ESP in an emission averaging option must "maintain the monthly fuel content values at or below the operating limit established during the most recent performance test. EPA should clarify why the presence of an ESP would require monthly fuel content determinations. It appears that the reference should be removed from the proposed regulation.

PPL appreciates the opportunity to provide comments on the Proposed Rule and urges EPA to give careful consideration of the comments of PPL and others to address the above concerns prior to promulgation of a final rule.