INSTITUTE OF CLEAN AIR COMPANIES

December 1, 2014

EPA Docket Center (Air Docket)
United States Environmental Protection Agency
Mail Code: 2822T
1200 Pennsylvania Avenue, NW
Washington, DC 20460

Attention: Docket ID Number: EPA–HQ–OAR–2013–0602

Re: Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units (June 18, 2014)

The Institute of Clean Air Companies (ICAC) appreciates the opportunity to comment on EPA's proposed Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units. ICAC is the national non-profit trade association of companies that supply air pollution control and monitoring systems, equipment, reagents, and services for stationary sources. Since 1960, ICAC has promoted the air pollution control industry and encouraged the improvement of engineering and technical standards.

Our members include over 80 companies who are leading manufacturers of equipment to control and monitor emissions of particulate matter (PM), volatile organic compounds (VOC), sulfur dioxide (SO2), nitrogen oxides (NOx), as well as mercury, acid gases, and other hazardous air pollutants (HAP). ICAC members are also on the forefront of developing controls for greenhouse gases (GHGs). ICAC is in a unique position to provide technical comments on this proposed rulemaking. ICAC's collective technical expertise is, and will continue to be, an important voice in the ongoing debate on how to cost-effectively reduce CO_2 emissions.

ICAC commends the Environmental Protection Agency (EPA) for its efforts with respect to proposing a regulation to obtain reductions in carbon dioxide (CO_2) from the existing power plant sector in support of the President's Climate Action Plan announced in the summer of 2013. From a process standpoint, EPA's extensive outreach to stakeholder groups, and its transparency in explaining a complex proposal, is particularly commendable. Also, from a substantive standpoint, ICAC supports EPA's underlying principle of offering maximum flexibility to states to develop their own plans within the statutory constraints of section 111(d) of the Clean Air Act.

For Best System of Emission Reduction (BSER) the EPA proposed regulation uses four (4) building blocks to reduce CO_2 emissions from existing power plants. The four building blocks are:

- Improve the net heat rate of existing coal fired power plants by 6%,

- Increase utilization of natural gas combined cycle (NGCC) units to 70% capacity factor,
- Expand the use of renewable energy and nuclear generation, and
- Increase demand side efficiency by 1.5% of prior year sales in annual savings.

The EPA indicates that combining these building blocks together would result in an overall reduction of CO_{2e} emissions of 30% by the year 2030 as compared to the 2005 emissions. ICAC believes that this is noble goal, however achieving this goal through implementation of the proposed building blocks will be very difficult to achieve, both technically and legally. The following is a summary of our comments.

I. Heat Rate Improvement

ICAC suggests EPA re-examine the impact of the proposed regulation, since we believe that in many instances, New Source Review (NSR) can be triggered. ICAC has seen in the past that modifications similar to those that may be required to improve a unit's heat rate have resulted in the issuance of NSR Notices of Violation (NOV). If a plant/unit tries to improve its heat rate, because of increased dispatch, there is the potential for increasing emissions and triggering NSR. ICAC would like to work with EPA to obtain the legislative changes to the NSR rule to make heat rate improvements more viable.

Historically, NSR has been such a concern for the electric utility industry that sources have been reluctant to invest in heat rate improvements for fear of reopening their permit to BACT analyses on the criteria pollutants for which they already have permits. With this concern, NSR provisions have been an unintended impediment to heat rate improvements in the coal fired sector. For this reason, it is difficult to assess what overall heat rate improvement is actually possible.

The EPA proposes an improvement in the heat rate of coal fired power plants by 6% while also seeking comments for a more conservative improvement of 4%. The EPA proposes that the 6% improvement can be accomplished at an average capital cost of $100/kW since two thirds (4%) of the improvement in heat rate could be accomplished using "best practices" for improving the current operation of the units and the remaining 2% could be achieved with capital improvements. ICAC believes that achieving the proposed 6% improvement or even the 4% alternative goal would not only be very difficult, both technically and legally, but is severely compromised by Building Block #2.

The EPA arrives at the proposed heat rates improvement using a statistical analysis that reviews the hourly heat rate, load and ambient temperatures over an eleven-year period for over 800 individual units. The EPA concluded that variability in heat rate for a unit at any given ambient temperature or load condition over the eleven-year period was indicative of a failure to use "best practices." While the ICAC agrees that there may be room for some improvement in heat rate, ICAC disagrees with the conclusion that 4% improvement is available through no or low cost "best practices." The following summarizes the technical basis of our disagreement:

a. EPA did not properly account for capacity factor and cycling duty

EPA's approach does not properly address the effects of capacity factor. EPA's approach regards average load over an hour as capacity factor, when industry actually averages capacity factor over longer periods of time. The approach used by EPA would consider an hour with load that is steady at 70% as equivalent to an hour where load changes from 40% to 100%, when in fact the boiler will behave very differently in these two situations.

b. Cooling water temperature has a large impact on heat rate

Ambient air temperature does impact heat rate, however its impact is not significant enough to be one of the primary factors in EPA's statistical analysis. ICAC believes that cooling water temperature would have been a more appropriate factor to consider in EPA's analysis. Changes in cooling water temperature, especially in the fresh water once-through cooling water systems, do not necessarily follows changes in ambient air temperature. Other factors such as cooling pond depth, river size, lake size, water chemistry, intake location, and ocean versus pond play an important role. A change in cooling water temperature of 10 °F could result in an increase in heat rate of approximately 1.5%.[1]

c. Changes in fuel can have an impact on heat rate

The EPA analysis does not take into account the impact of fuel changes and more specifically moisture content and ash chemistry changes. There have been a significant number of plants that have switched to higher moisture western coal in order to meet emission requirements. These plants have subsequently seen an increase in heat rate due to the latent heat of vaporization loss of the water present in the fuel and the additional parasitic energy required to dry the coal prior to its combustion. Wet (rain or snow) weather also impacts the moisture content of coal as coal is stored outdoors.

Besides the effect of additional moisture and lower heating value of those fuels, furnace, superheater, reheater, and economizer fouling with glassy, hard to remove deposits (alkaline earth) have a negative effect on heat rate because those insulating deposits make it more difficult to maintain the design superheat and reheat steam temperatures. This may cost 1% heat rate deficit in and of itself. There are solutions for this, but NSR provisions can be an obstacle to consideration of these solutions.

d. EPA's statistical analysis fails to account for other important factors

The EPA used statistical analysis to establish the heat rate improvement that is available through operating a unit using "best practices". In this analysis the EPA examined hourly heat rate, capacity factor and ambient air temperature data. The EPA then assumed that significant variations in heat rate over the 11 year period at a given load and ambient temperature was an indication that there was room for heat rate improvement through no or low cost "best practices." The issue with this analysis is that it presumes that ambient temperature and load are the only factors beyond the operator's control that impact heat rate. The analysis does not consider unit design, changes in cooling water temperature, or fuel heating value and moisture content, coal ash composition changes, extreme weather conditions, rate of load change, equipment changes over the period and/or wear, etc. According to the EPA's

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[1] "Power Generation from Coal: Measuring and Reporting Efficiency Performance and CO_2 Emissions", International Energy Agency, 2010.

statistical analysis, ambient temperature and capacity factor only explain approximately 25% of the variation in heat rate - leaving about three quarters of the variation unexplained. The unexplained variation, EPA apparently assumes, is due to a failure to use "best practices" rather than other, unaccounted for factors that are beyond the operator's control. ICAC's concern is that because EPA did not consider enough of the factors beyond the operator's control that impact heat rate, the approach used by EPA mistakenly considers the unexplained variation in their two-factor analysis as an opportunity for improvement in heat rate rather than the effects of other important factors that were not considered. [2]

e. Heat rate improvements are site specific

Each power plant is unique and is designed for an optimum heat rate at the time of its design/construction. Over the course of its life each plant has undergone physical (e.g., repairs, cooling water system), operational (e.g., fuel composition changes), and regulatory (e.g., installation of pollution control equipment, grid dispatch changes) that has altered its original optimum heat rate. Some of the plants may be able to improve their heat rate to the levels suggested by the EPA while others may not be able to do so. As the National Coal Council indicated in its report[3], many of the heat rate improvements "are not a one-size fits all package of solutions". As the report indicates some plants may not see any improvements as they may be operating in most efficient mode or changes over the years (e.g., fuel composition) may not allow any further improvement.

II. Increase Utilization of Natural Gas Fired Combined Cycle Units

The EPA proposes that the Natural Gas Combined Cycle (NGCC) unit's capacity factor is increased to 70% from its current level of approximately 48%. NGCC units have lower (i.e., are more efficient) heat rates than coal fired units, however ICAC believes that increasing their capacity factor (a) would result in a reduction in the coal fired units' utilization, and (b) could be detrimental to the reliability of the grid.

a. Reduces the coal fired unit utilization and hence increases its heat rate

As indicated above, operating a unit at reduced capacity will increase its heat rate and it could negate any gains that may have been made under the first of EPA's building blocks. Given the low projected increase of electricity demand and the proposed increase in the utilization of NGCC units, ICAC estimates that a reduction of approximately 5% (using the 2012 data) in the coal unit capacity factor is possible. This reduction in capacity factor could negate a major portion of heat rate gains that may have been made under building block one. (see graph on page 11)

b. Grid reliability could be reduced as its dependence on natural gas in increased

Coal fired plants have on average a thirty-day supply of energy on-site, whereas natural gas fired plants typically have no fuel storage capability. During last winter's "polar vortex" weather event in the PJM interchange, over 9,000 MW during a peak demand day of natural gas fired units went into a "forced

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[2] More detailed analysis of EPA's study and another similar study is provided in Appendix B.

[3] http://www.nationalcoalcouncil.org/NEWS/NCCValueExistingCoalFleet.pdf

outage" due to natural gas fuel curtailment. There was simply not enough natural gas transportation capacity available to satisfy the home heating and power generation needs of the area. On January 7 2014, when temperatures fell to below zero, near a quarter of the PJM operators faltered due to low temperatures, with natural gas generators being 47% off line at one time[4]. As the AEP CEO indicated, during that month the PJM set 8 of its 10 all-time winter generating records. The AEP CEO also indicated that almost 90% of the planned 7,100 MW of AEP coal unit retirements were called to operate during that time.[5]

III. Increase Renewables Generation and Encourage Nuclear Power Generation

The third building block encourages states to, among other things, increase renewable energy generation in the form of solar, wind, etc. Use of renewable generation is, by regulation, already an integral part of many states' resource plans. We should not however lose sight of the challenges that renewables present to maintaining smooth and reliable delivery of electricity to the public. One of the major issues with renewables is their impact on the electric grid's reliability due to the intermittent nature of their operation. Another is the inability to match the times of peak electric demand with renewable energy availability (e.g., sun, wind, etc.). As a result, the grid requires fossil units to be used as backups resulting in their operation at low loads and hence increased heat rate operating regime (i.e., low efficiency) as discussed above.

IV. Demand Management

Greater investment in energy efficiency has huge potential to conserve demand and can have a significant impact on greenhouse gas reduction from power plants, particularly when technological and cost constraints can limit the degree of improvements realistically possible at the plants themselves. There are several active and passive approaches to demand reduction and peak shaving at various stages of development or implementation today. For example, ICAC members are actively involved in developing technologies for reducing energy demand by up to 30% from commercial buildings.

Transmission and Distribution (T&D) of electricity accounted, in 2005, for approximately 6% of net electricity losses[6]. Improving T&D through the use of higher voltage, HVDC, or improved efficiency for distribution transformers would also reduce emissions. We believe that the EPA should be discussing this option for reducing emissions with the appropriate federal agencies.

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[4] http://www.bizjournals.com/columbus/print-edition/2014/09/05/aep-warns-of-grid-reliability-issues-in-bad.html?page=all.

[5] http://www.eenews.net/stories/1059997757.

[6] https://www.nema.org/Products/Documents/TDEnergyEff.pdf.

V. Comments to the Notice of Data Availability (NODA)

In Section VI. B.2 of the preamble, EPA cites that gas co-firing would give rise to reduction in CO_2 emissions in approximately linear relationship to the degree of co firing implemented. The agency brackets the cost per ton of CO_2 reduced as \$ 83 - 150 /ton. Building block 2, the least cost effective of the four building blocks proposed by EPA, was estimated by the EPA to cost \$30/ton. Based on these costs co-firing gas in a coal-fired unit seems an unnecessarily expensive approach to comply with CO_2 emissions guidelines and seems inconsistent with the definition of BSER. ICAC believes that the final Clean Power Plan should encourage coal utilization, and improving heat rate to technically achievable levels in a sustainable way in those plants should be a mandatory step before building blocks 2 and 3 are considered.

More detailed information is provided in our comments below, and ICAC will be glad to provide additional information and clarification to the EPA.

Sincerely,

Betsy M. Natz

Betsy Natz
ICAC Executive Director

Table of Contents

Appendices

I. Primary Comments

Introduction

ICAC commends the Environmental Protection Agency (EPA) for its efforts with respect to proposing a regulation to obtain reductions in carbon dioxide (CO_2) from the existing power plant sector in support of the President's Climate Action Plan announced in the summer of 2013. From a process standpoint, EPA's extensive outreach to stakeholder groups, and its transparency in explaining a complex proposal, is particularly commendable. Also, from a substantive standpoint, ICAC supports EPA's underlying principle of offering maximum flexibility to states to develop their own plans within the statutory constraints of section 111(d) of the Clean Air Act.

As suppliers and developers of air pollution control systems and therefore intimately involved in the day-to-day operations of electrical generation units, ICAC is in a unique position to provide technical comments on the proposed rulemaking. ICAC's collective technical expertise is, and will continue to be, an important voice in the ongoing debate on how to cost-effectively reduce CO_{2e} emissions. The expertise of ICAC member companies is a key resource for addressing the technical issues related to heat rate improvement, the primary building block "within the fenceline." We offer comments below on many of those issues.

A. ICAC's Primary Issue – New Source Review Continues to be an Impediment to Potential Efficiency Improvements

The proposed regulation discusses its implications for the New Source Review (NSR) program. (79 FR 34928-34929) NSR is a preconstruction permitting program requiring major stationary sources of air pollution to obtain permits prior to the start of construction.

The proposed rule indicates that "as part of its Section 111(d) plan, a state may impose requirements that require an effected EGU to undertake an operational change to improve the unit's efficiency that results in an increase in the unit's dispatch and an increase in annual emissions." (79 FR 34928/2) The NSR rule is explicit: creditable increase in "actual emissions" is the amount by which "the new level of actual emissions exceeds the old level."

ICAC would like the EPA to further examine the impact of the proposed average coal-fired plant heat rate improvement through (a) the actual pounds per hour increase in emission(s) of specific pollutants and (b) the net increase in emissions as a result of unit physical or operational changes.

Regarding item (a), increase of specific pollutant following physical or operational modifications to the unit, we do not anticipate any obvious "significant" increases in typically permitted emissions for coal fired power plants except for modifications to the combustion systems. If implementing any of these heat rate improvements other than combustion modifications there should be a decrease in SO_2, NO_x, and PM emissions assuming no increase in capacity factors. However, certain combustion modifications to improve heat rate could increase CO emissions (e.g., reduction in operating excess air) beyond the 100 tons / year significance level assuming no increase in capacity factor.

Regarding item (b), net increase in tons/year of emissions, we see modifications that although they do not increase individual pollutant levels, could result in an increase in operating hours and hence a net tons/year increase of pollutants.

Block Andrews of Burns & McDonnell has compiled a summary of historical NSR violations and then compared this list with the heat rate improvements as presented in the Sargent& Lundy NETL reports used by EPA in their evaluations. This summary clearly shows that clarification needs to be provided to give EGUs certainty before committing to heat rate upgrades.

Activity	Assumed Heat Rate Improvement		NSR NOV Project Identified by EPA*	Potential Non-NSR Heat Rate Improvement	
	S&L (Btu/kWh)	NETL (percent)		S&L (Btu/kWh)	NETL (percent)
Economizer Replacement	50 - 100	2.1	Yes	0	0
Neural Network	50 - 100	0.2 - 2.0	No	50 - 100	0.2 - 2.0
Intelligent Sootblowers	30 - 90	0.1 - 0.65	No	30 - 90	0.1 - 0.65
Air Heater/Duct Leakage	10 - 40	0.16 - 1.5	Yes	0	0
Lower Acid Dewpoint (Trona)	50 - 120	Not listed	No	50 - 120	Not listed
Steam Turbine Upgrades	100 - 300	0.84 - 2.6	Yes	0	0
Clean Condenser	30 - 70	0.7 - 2.4	No	30 - 70	0.7 - 2.4
Boiler Feed Pump	25 - 50	Not listed	No	25 - 50	Not listed
Fan replacement/VFD	30 - 150	Not listed	No	30 - 150	Not listed
Misc. AQCS upgrades	0 - 65	Not listed	Yes	0	Not listed
Cooling Tower	0 - 70	0.2 - 1.0	No	0 - 70	0.2 - 1.0
Other	0 - 20	Not listed	No	0 - 20	Not listed
Ash Removal System	Not listed	0.1	No	Not listed	0.1
Combustion system optimization	Not listed	0.15 - 0.84	No	Not listed	0.15 - 0.84
Feedwater heaters	Not listed	0.2 - 2	Yes	Not listed	0
Flue Gas Moisture Recovery	Not listed	0.3 - 0.65	No	Not listed	0.3 - 0.65
Coal Drying	Not listed	0.1 - 1.7	No	Not listed	0.1 - 1.7
Reduce slagging	Not listed	0.4	No	Not listed	0.4
Steam Leaks	Not listed	1.1	No	Not listed	1.1
Total	375 - 1,175	6.95 - 20.54		215 - 670	3.55 - 12.84

*Some additional activities not specifically flagged in this column to trigger NSR could still trigger NSR. For example, for steam leaks that are significant enough that require significant replacement of parts could trigger NSR.

Therefore, the legal question of whether these heat rate these modifications can be implemented without triggering NSR, is as important as the practical engineering or economic concerns. From an owner's perspective, any modification, maintenance or repair made at a power plant must be evaluated with the objective of avoiding modifications that trigger a need for reduced emissions limits under the NSR program that would then require much higher capital investments. One example of a simple upgrade that can trigger an NSR action is if a 500 MW plant upgraded their coal burners. Under the circumstances, an increase in CO emissions by as little as 10 ppm would exceed the 100 ton/year PSD limits. As a result, heat-rate improving activities might improve net output or dispatch or make the plant economically viable for a longer period of time. Even if EPA includes in its final rule means to mitigate this concern, it will not be determined until the conclusion of any ensuing litigation whether EPA, in fact, has the authority to do so.

B. The Expected Emissions Reductions from Heat Rate Improvements Will be Offset by Increasing Natural Gas Capacity to the 70% Goal

The basis of ICAC's primary concern with the proposed Clean Power Plan lies in the following graphs which illustrates the impact of unit capacity on heat rate:

Figure 1 plots the impact of load on heat rate for both subcritical and supercritical boilers. Part load operation will result in a higher heat rate than at full load.

Figure 1. Effect of load on heat rate. [7]

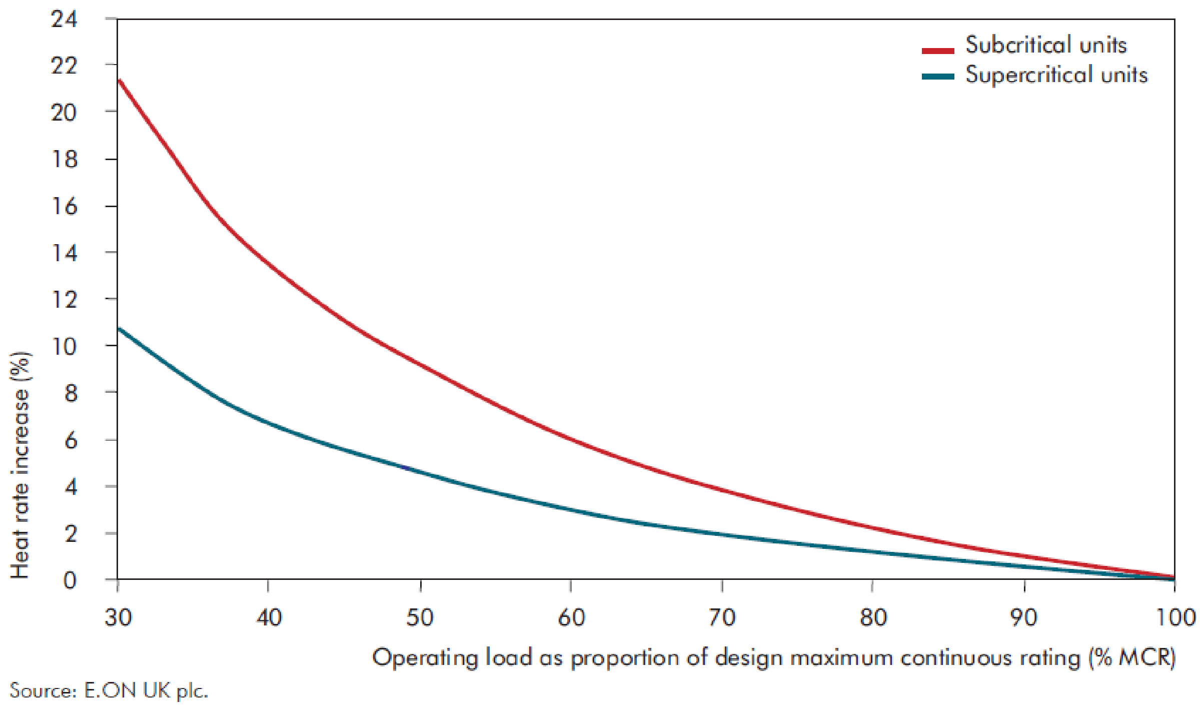
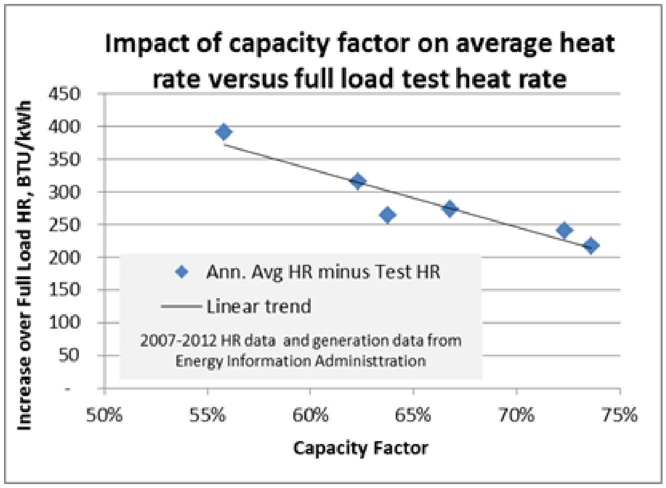


Figure 2 shows the impact capacity factor had on heat rate for the US coal fleet during the period from 2007-2012. Each year is plotted as a data point. EIA data on fleet average full load test heat rate was compared to fleet average actual heat rate for each year. Generation and capacity data were used to determine average capacity factor. As shown, there is a clear trend toward higher heat rates at lower capacity factors.

[7] As published in IEA, "Power Generation from Coal Measuring and Reporting Efficiency Performance and CO_2 Emissions"

Figure 2. Impact of Capacity Factor on heat rate for US Coal fleet (data from EIA, 2007-2012))



The impact of unit operating load on heat rate has not been given adequate attention as it relates to the application of the proposed rule. The EPA based the proposed rule on four building blocks: (a) heat rate improvement of the coal-fired fleet, (b) increased utilization of the natural gas combined cycle units, (c) increased reliance on existing nuclear units and renewables and (d) a reduction in the electricity demand side. The latter three "building blocks" will force the coal-fired fleet to assume a greater load-following role in the electric generation. It is well known by plant operators that a reduction in operating load of a coal-fired unit will result in a higher heat rate.

Therefore, the proposed coal-fired fleet average heat rate improvement of 6%, particularly when combined with the impact of increased utilization of the natural gas combined cycle (NGCC) units and increased generation from renewables (see Appendix F), will result in an overall reduction in the utilization of the coal fired units. Reducing the average operating load of the plant will result in a degradation of the heat rate and loss of some of the efficiency gains made as a result of implementation of EPA's proposed coal-fired heat rate building block.

C. EPA's Anticipated Improvement in Heat Rate for Coal-fired Power Plants Through "Best Practices" is too Optimistic

Using a statistical analysis that presumes that a well-controlled coal unit should have very consistent heat rate under a given ambient temperature and average hourly load over the eleven-year period that was evaluated, EPA reached the conclusion that 4% improvement in heat rate was possible on average by increased use of no or low cost "best practices." Variation in gross heat rate outside of these two variables was regarded as an opportunity to improve heat rate. Unfortunately, this approach does not adequately address all of the factors beyond the operator's control that impact heat rate. Over this period many facilities made significant changes to their plants in response to environmental regulations that would impact heat rate, to include changes in fuel, addition of new equipment, etc. In the statistical analysis used by EPA, variation in heat rate resulting from these other factors that are beyond the operator's control is mistaken as variation that can be improved through "best practices." As a result, the analysis by EPA reaches an incorrect conclusion about the opportunities to improve heat rate through "best practices."

As we have seen from the data presented in these comments the heat rate of a plant is impacted by many components. Some of the most significant components of heat rate that EPA did not include in their statistical analysis were the fuel burned, the heating value of the fuel, and the yearly variation in the fuel burned for power generation. The heating value of coal is primarily impacted by the water content of the coal since water has to be evaporated during combustion.

During the period of 2002 to 2012 that EPA used in their analysis, the use of bituminous coal decreased by about 10% while subbituminous coals (particularly from PRB) increased by 28%. However, actual usage of coals varied significantly during this period. Bituminous coals varied + 12% to a – 24% for the yearly average. PRB coals varied +8% to -12% from its annual average usage.

PRB fuels typically have about 25% moisture content and a heat value of 8,700 Btu/lb. Bituminous coals generally have less than 10% moisture and a heating value of 11,900 Btu/lb. As a result of the increase in PRB and decrease in bituminous coal during the evaluation period that more than 7% water was "combusted" in coal generation resulting in significant heat rate impacts on the coal fleet. According to EIA data there was significant annual variations in moisture content (and ash content from 8-30%) of the fuel combusted during this period that resulted in more than the 6% used as its model to justification for heat rate improvements.

II. General Comments on Building Block One

EPA's proposal for Building Block One of the Clean Power Plant (CPP) is based on improvements in power plant heat rate at existing coal-fired power plants. The following questions need to be considered in evaluating EPA's rule:

- Are the opportunities for up to 6% improvement in heat rate across the entire coal fleet currently available?
- Are they more available with amended NSR language?
- If a utility made an investment to improve their heat rate above their normal or routine maintenance practices, what return on equity can they achieve?, and
- Can these modifications be performed without triggering New Source Review (NSR)?

EPA has concluded that up to a 6% heat rate improvement could be obtained at an average capital cost of $100/kW. EPA stated that 4% of the heat rate improvement, on average, is achievable through no or low cost options they refer to as "best practices" and the remaining 2% improvement is achievable with some capital expenditure. Since a number of the larger supercritical plants already have upgrades that may limit heat rate improvements to about 1%, that means that other plants may have to achieve upgrades greater than 10% which is not practical.

EPA's conclusion that 4% improvement using "best practices" is possible at no or low cost was based upon a statistical analysis of over 800 units using what EPA describes as statistical process control methods. For each unit, the gross heat rate in a given hour over an eleven year period was compared against hourly National Oceanic and Atmospheric Administration (NOAA) ambient temperature data and hourly average load as a percent of maximum load. EPA calls the average hourly load (expressed as a percent of maximum load) capacity factor, although industry consider capacity factor as averaged over a much longer averaging time than an hour). The degree that heat rate for the unit is consistent or inconsistent over the eleven year period for any given temperature and hourly average load is, EPA states, a measure of how well or how poorly the facility is being controlled. A well-controlled unit should, they argue, have very consistent heat rate under a given ambient temperature and average hourly load. To the extent that there is scatter in gross heat rate for any given hourly load or temperature condition over this eleven year period, EPA considers that a sign that more consistent process control can improve heat rate.

The statistical approach used by EPA does not consider any technical aspects of the facility, or if any characteristics changed over the eleven year period of time, such as if a facility was operating in a cycling mode, had retrofit low NOx burners, SCRs, scrubbers, new burner and furnace management systems etc., or if the facility changed coals over this period, or any characteristics of the fuel for that matter. EPA also did not compare units against one another nor do any sort of subcategorization. Each unit is only compared against itself over that eleven year period, and in that respect, subcategorization is avoided.

EPA states that an additional 2% of heat rate improvements to get to 6% are available with some expense (presumably, most of that \$100/kW). To put things in perspective, \$100/kW is about one fifth the cost of a wet scrubber. So, that is an expense that is not excessive for most power plants. The one sticking point is concern about New Source Review. In a 2013 paper published in Power Magazine prepared by ASME's Research Committee on Energy, Environment and Waste titled "The Case for Fuel Delivery System Upgrades on Utility Boilers" they found that by upgrading the fuel delivery system they could achieve a 0.34% improvement in boiler efficiency on a 500 MW wall fired coal boiler at a cost of \$13,600,000. A major steam turbine overall/upgrade for a 500 MW can cost between \$30-50 million.

III. Best System of Emission Reduction (BSER) Status

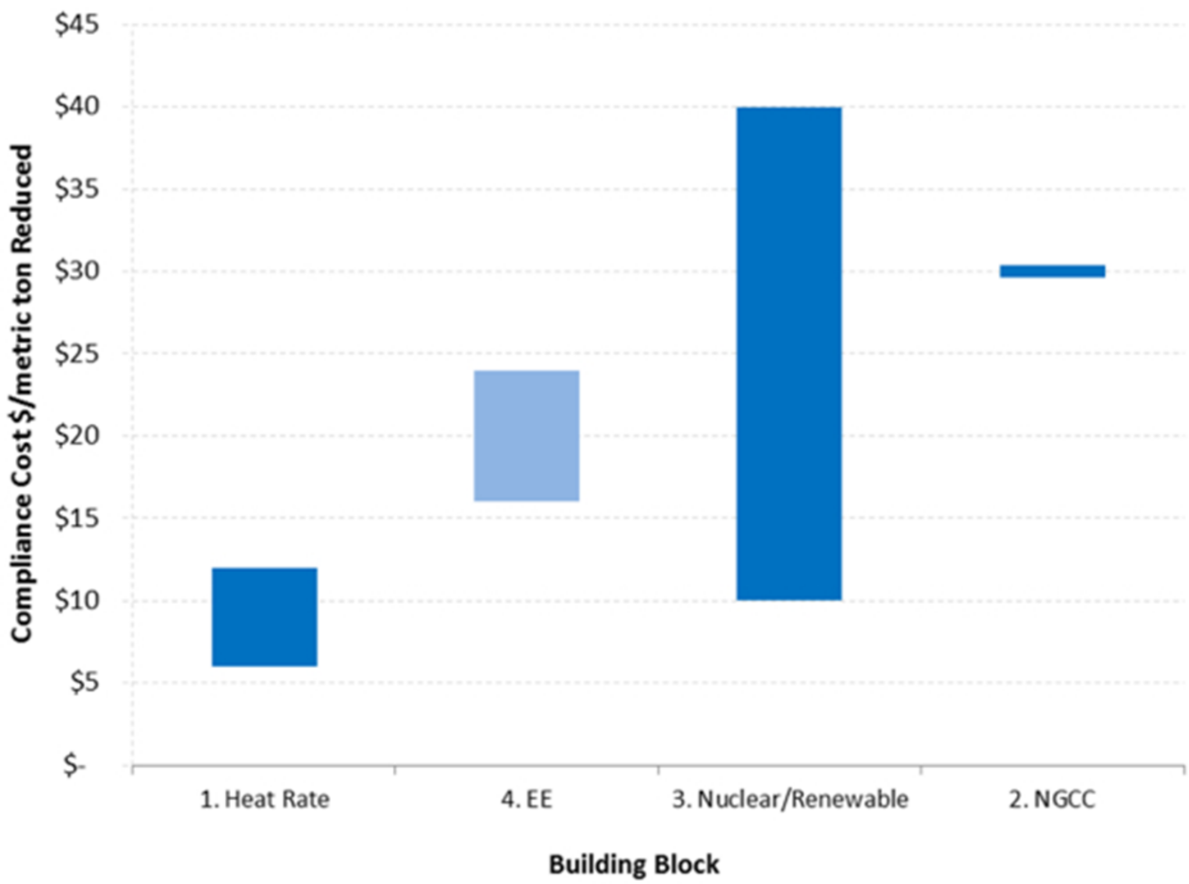
EPA has requested comments regarding potential BSER status of the four building blocks, and proposed combinations of the four building blocks. §111(a)(1) of the Act provides that NSPS are to "reflect the degree of emission limitation achievable through application of the best system of emission reductions which, **taking into account the costs of achieving such reduction** and any non-air quality health and environmental impact and energy requirements , the Administrator determines has been adequately demonstrated." This level of control is commonly referred to as best system of emission reduction (BSER).

§111(d) guidelines, like NSPS, must reflect the emission reduction achievable through BSER while recognizing that existing sources may not have the capability to achieve the same levels of control as the new sources. The statute and EPA's regulation in 40 CFR 60.24 permit states and EPA to set less stringent standards….when warranted, considering cost of control, etc.

EPA has established in its analyses and published in the Preamble to the § 111(d) proposal cost effectiveness ranges for its building blocks. In decreasing order of cost effectiveness (as measured in $ / metric ton CO_2 reduced) they are:

1) Heat rate improvement in coal-fired units - $6-$12 / ton CO_2 (Building Block One)
2) Demand-side management programs - $16-$24/ ton CO_2 (Building Block Four)
3) Increased use of renewable generation - $10-$40 / ton CO_2 (Building Block Three)
4) Increase NGCC capacity factor to 70% (from 46% currently) - $30 / ton CO_2 (Building Block Two)

Figure 1: EPA Estimated Cost Range ($/metric ton CO_2 Reduced) of Building Blocks



On its face, increasing the capacity factor of NGCC sources significantly to 70% (Building Block Two in the proposed rule), represents the most costly option among the four building blocks. Moreover, it would have the undesirable effect of providing a disincentive to a coal-fired source to invest in building block One, the lowest cost building block, because coal-fired plants high in the dispatch order with low generation costs, that would otherwise invest in heat rate improvements, would then not do so because of stranded costs when they are no longer required to operate at base-load. The choice of Building Block #2 with its extreme manipulation of dispatch order contravenes the intent of BSER by displacing the most cost-effective tranche of CO_2 tons in favor of those reduced by increasing NGCC. The first tons of CO_2 would be reduced at an average of $30/ton instead of say, $9/ton.

Further to the issue, forced increase of NGCC sector capacity factor will disincent investments to improve heat rate in the coal -fired sector because those costs will be stranded to the degree the coal sector capacity factor is diminished. An unintended consequence would be that the lowest cost tons of CO_2 reduction will have been displaced by the highest (among the building blocks), thus highly compromising the BSER cost effectiveness criterion.

The issue of "rebound" whereby heat rate improvements would cause increase in utilization of coal-fired capacity, though cleaner with respect to CO_2 intensity, should only be a concern for emissions with acute local effects…. such as mercury and ozone. Acknowledging that "climate change" is a global phenomenon with extraordinary political, social, and economic ramifications, focus on the controls of CO_2 should be on cost effective reductions overall. With a proposed regulation that purports to allow regional controls, and considering that electrical demand is finite on any given day, cost effective cleaner power from coal should be an objective. As an example, an 800 MWe unit in Pennsylvania that decreases heat rate by 500 BTU/kwh thereby causing an increase in utilization of 5% implies a more marginal unit in Kansas has decreased its output of otherwise higher CO_2 intensity emissions .There is a net benefit relative to CO_2 emissions, at lower marginal cost.

IV. Impacts of Increased Renewable Usage - Lessons from Europe on the Impact of Renewables

Large penetration of intermittent renewables will have a significant implication on many aspects of power system planning, operation and control. Fossil generation plants have made extensive investments in environmental technology to ensure our electrical generating system in the US is the cleanest in the world, regardless of the source of that electrical generation. ICAC member companies are instrumental in the significant achievements in clean air technology. The impact of this regulation will be the stranding of these assets, raise the cost of operating them due to load cycling, and possibly raise the costs of meeting long term service agreements put in place before the onset of rapid and frequent cycling. It will also have the impact of diminishing future investments in clean air technology.

The increase in the use of renewables brings into discussion the relative impacts of economic versus environmental dispatch. Some observations from Europe's experience suggest that issues related to over-reliance on renewables could cause problems if not addressed properly.

- In Europe, only 4% of the wind installed capacity has a probability of being available 95% of the time.

- Solar power is characterized by diurnal patterns and is well correlated with hours of high demand. However, large fluctuations in output are observed.

- Peak of thermal production no longer occur when demand is highest. Wind may result in such a low value of net demand (mostly at night) that forces a large number of thermal units to shut down only to have to start up a few hours later.

Conventional generation is dispatchable, and can be controlled primarily based on economic attractiveness at every point to supply reliable electricity. The lowest marginal generation is dispatched first and then moving up the curve. Because most renewables are intermittent and not dispatchable as conventional plants, they cannot be controlled by economic dispatch. Therefore, system operators must respond to conditions in real time.

By putting environmental dispatch as the first priority, Europe created an artificial market that encouraged the significant over-investment in renewables and exaggerated the impact of renewables on grid integrity. EU legislation requires that "Member States shall ensure that when dispatching electricity generating installations, system operators shall give priority to generating installations using renewable energy sources insofar as the secure operation of the national electricity system permits and based on transparent and non-discriminatory criteria."[8] The practical effect of this rule is that production from renewables can only be limited by security reasons. There was no central planning governing the expansion of renewables, and this created an artificial economic condition that did not necessarily result in the lowest energy prices.

In addition, the regulation for wind or solar created a situation whereby a renewable power company may also be willing to bid a negative price to retain the income from any financial support scheme that is linked to production. Therefore, whenever the market price equals zero or a negative value, even if the optimal solution is to curtail wind rather than stop a conventional thermal plant for a short period of time, renewable production will be scheduled to receive the feed-in tariff or premium, if this is the case. This should not be considered acceptable.

Conventional power plants should not be penalized for the inability of non-dispatchable power to meet peak demand. A different approach is needed to consider the cost of achieving environmental benefits, including subsidies that are not being considered.

ICAC believes renewables are an important source of electricity. However, systems must be in place to ensure that artificial market mechanisms or regulations are not established that encourages the deployment of assets favoring of a single technology that could aggravate the intention of ensuring a reliability electrical system. There is also a synthetic benefit constructed for Building Block #3 to the extent that investment tax credits confound the stand-alone cost-effectiveness of that Building Block #3,

[8] European Commission EC/2009/281 Renewable Energy Directive Article 16(2)(c)

which falsely enhances its attractiveness under BSER. What is the true cost-effectiveness of Building Block #3?

V. Specific Comments

A. Building Block One - The Proposed Heat Rate Improvement Is Technically and Economically Challenging

The proposed EPA Clean Power Plant regulations for existing power plants use four "building blocks" as Best Emissions Reduction System (BSER). The first "building block" suggests that existing coal fired power plants improve heat rate by 6%, thereby reducing the amount of fuel being burned and associated emissions of carbon dioxide (CO_2). Heat rate is expressed as the amount of energy required to generate a unit of electrical energy and it is typically measured in the US as Btu/kWh (net). Net heat rate refers to the electric energy the plant sends out to the electric grid whereas gross refers to the total energy generated by the plant and accounts for the electric energy being sent to the grid plus the electric energy that is consumed by the power plant itself.

As EPA's "Technical Support Document (TSD) for Carbon Pollution Guidelines for Power Plants" (EPA-HQ-OAR-2013-0602) indicates, there are many factors that impact a plant's heat rate, including:

- The plant's design thermodynamic cycle
- Coal composition and quality
- Age and size
- Presence of pollution control equipment
- Operating and maintenance practices
- Plant component design
- Geographic location and ambient conditions
- Cooling/Condenser system
- Electric grid dispatch requirements

We agree with EPA's conclusion that the above factors impact a plant's heat rate. Our members believe that there is definitely room for improving a plant's heat rate. We would like to caution the EPA that the suggested fleet average improvement when combined with the impact of the other building blocks such as increased utilization of the natural gas combined cycle (NGCC) units, increased generation from renewables, and the reduction in demand will most likely result in an overall reduction in the utilization of the coal fired units. Reducing the average operating load of the plant will result in a degradation of the heat rate and loss of some of the efficiency gains made as a result of EPA's proposed coal fired heat rate building block. The impact of unit capacity on heat rate is discussed in more detail below.

ICAC offers three examples to support its position that a further 6% heat rate improvement is not as readily achievable as EPA believes:

The first example is included in EPA's TSD on pages 2-32 and 2-33, where EPA's Region 7 reported that seven coal units performed equipment modifications such as turbine and condenser upgrades, variable frequency drives. Region 7 reported that together all of these modifications achieved a 0.25 to 3.5% improvement in heat rate. Another utility (WEPCO) reported improvement of 2.3 to 4.1% due to equipment upgrades and only a 0.5% per year improvement using best practices. In summary, the example indicates that well thought out modifications to unit design and operation only resulted in a maximum improvement of approximately 4% in heat rate. Having performed these improvements these seven units would have difficulty in further improving their heat rate to the stated 6% goal.

The second example addressing the variability between plants is found on page 2-25 of EPA's TSD, where ambient temperature, according to EPA's analysis plays an important factor in nearly 25% of the 800+ units studied. The EPA report indicates that most of these units, typically equipped with once through fresh water cooling units, showed an increase (i.e., decrease in efficiency) in heat rate of 2% to 4% during the summer months are compared to the winter months with a "temperature responsive EGU [electric generating unit] that figure may be as high as 10%". Part of the reason for this increase is indeed higher ambient temperatures (i.e., higher fan duty, etc.), however the major reason is most likely the increase in cooling water temperatures used by the plant. A 10 °F increase in cooling water temperature <u>increases</u> heat rate by approximately 1.3% due to an increase in condenser back pressure. It should be pointed out that summer months produce the highest capacity factor (see Figure 2-3, page 2-24 of EPA's TSD), where operating at high capacities produces the most favorable heat rate. In summary, the example provides evidence that factors beyond an EGU operator's control (such ambient temperature) play an important role in heat rate.

A third example that summarizes the impact of the three major issues presented above, includes the situation at the McMeekin station in South Carolina, a 250 MW plant, that ranks as one of the most efficient power plants in the US even though it operates at a subcritical pressure cycle and is 60 years old. The primary reason for this high efficiency is its access to 45 °F year round cooling water, generating a very highly efficient condenser system resulting in low heat rates. Availability of such a low cooling water temperature for a power plant is rare. The article juxtaposes the McMeekin station with the Belews Creek station in North Carolina, the second most efficient coal plant operating in the US last year according to Electric Power & Light[9]. The Belews Creek plant design is based on the most efficient design at the time of its construction and uses best operating practices resulting in high operating efficiency. Due to these factors it will have difficulty improving its heat rate. We believe that it will have difficulty in achieving the stated 6% goal even if it is averaged into the North Carolina grid due to its size (approximately 2,300 MW) and high capacity (80%) factor.

B. Building Block Two - Re-dispatching From Coal to Gas

As the industry moves toward greater integration of gas turbines into the power generation mix, ICAC companies have been integral in ensuring criteria pollutant emissions reductions from both CCGT and SCGT are the lowest possible. Since the gas turbines being installed now will be a larger percentage of

[9] http://www.elp.com/articles/print/volume-89/issue-6/features/operating-performance-rankings-2010-top-20-power-plants.html.

the installed base for the next 40 or more years, ICAC members are ready to provide the most state-of-the-art control technologies to ensure the cleanest air possible. Not all gas turbines are operated with NOx or CO controls, but there are over 800 gas turbines (SCGT and CCGT) use oxidation catalyst and over 1000 turbines use SCR controls.

C. Building Block Four - Energy Efficiency

Greater investment in energy efficiency in commercial buildings has huge potential to cut and manage demand.

1. An Energy Savings Approach with Significant Greenhouse Gas Reductions

Energy demand reduction can have a significant impact on greenhouse gas reduction from power plants, particularly when technological and cost constraints can limit the degree of improvements realistically possible at the plants themselves. There are several active and passive approaches to demand reduction and peak shaving at various stages of development or implementation today.

One leading innovative approach has been developed and demonstrated to reduce the energy consumption in HVAC systems in commercial and public buildings by up to 50% at peak loads. The concept involves selective removal of gas contaminants from indoor air as a practical substitute for outside air ventilation, as is the normal practice in commercial buildings today. This enables recirculation of most of the indoor air and greatly reduces the amount of makeup air. This in turn reduces the HVAC load and results in significant energy savings for the facility. Key to this approach is low cost removal of all gas contaminants from indoor air using novel, efficient and regenerable sorbent materials. The total System solution is implemented by means of air handling modules that can be retrofitted onto virtually any building. The system uses novel sorbents that have largely been developed by the US DOE.

The energy savings stem from the significant contribution of makeup air to the total cooling or heating load of typical code-compliant current-day HVAC systems. This makeup (outside) air can represent up to 50% of the total HVAC load in hot & humid climates, or conversely in very cold climates. The technology is the first of its kind that provides a winning solution – significant energy savings without compromising indoor air quality. At installations in commercial buildings in San Antonio, TX, Houston, TX and Israel, a 30-40% reduction in average daily cooling energy has been demonstrated. Several other sites in the US and abroad are currently in the works.

The impact of such an approach can be massive on a regional and national scale. Widespread deployment of such a technology can actually “move the needle” at the national scale, given the relative importance of commercial building HVAC energy consumption. The initial targets will be office buildings, large retail stores, schools and healthcare facilities.

The U.S. has approximately 40 billion sf of commercial space. Each system can save approximately 25000 kWh/year, or reduce CO_2 generation by ~ 17 metric tonnes/year. Table 1 shows the estimated annual GHG reduction for various penetration rates of the technology into the available commercial building space in the U.S. using the EPA's greenhouse Gas Equivalents Calculator.

It is clear that very meaningful and substantial reductions in GHG's are possible from the adoption of such technologies. The strength of such an approach is that in addition to reducing GHG's, there is a financial incentive and attractiveness from the viewpoint of building owners (energy cost savings) and utilities creating a win-win situation.

Table 1: CO_2 reduction resulting from the demand reduction enabled by this technology

Commercial Area Deployed, million Sq ft	**Energy Saved per Year, in million kWh**	*** CO_2 Reduction, million metric T/year**
800	2000	1.4
2000	5000	3.4
4000	10000	6.9

*Source: U.S. EPA website, Clean Energy Page, Calculations & References

Appendix A – New Source Review

In order to trigger NSR, an existing source would have to implement a "Major Modification". A Major Modification is **any <u>physical or operational change</u> of an existing major source that would result in a <u>significant</u> <u>net emissions increase</u> of any pollutant subject to regulation under the CAA**. In most cases, a major modification must cause two emission increases; a significant emission increase and a significant <u>net</u> increase. **Physical/operational change excludes routine maintenance, repair and replacement (RMR&R).** NSR court cases have been inconsistent defining "routine maintenance", however, some of EPA's NSR Notice of Violation (NOV) have identified items such as economizer replacement, steam turbine upgrades, feedwater heater replacements and other activities as "non-routine" maintenance. Some court case decisions have agreed with EPA on the "non-routine" activities however some courts case decisions have not agreed with EPA's "non-routine" activities. It should be pointed out that some of these modifications could be necessary to improve a plant's heat rate.

The proposed regulation goes on to say that "if the emissions associated with unit's changes exceeds the thresholds in the NSR regulations i.e., the levels shown in the Table above for one or more regulated NSR pollutants, including the netting analysis, the changes would trigger NSR. We've looked at a typical 500 MW bituminous coal fired unit. Typical CO emissions for this type of plant would range from 0 to 50 ppm of CO. One approach to improving heat rate would be to lower excess air if possible. When the excess air is lowered one problem could be an increase in CO emission. Assuming a 10 ppm increase in CO this typical 500 MW unit having a heat rate of 10,300 Btu/kWh and a 70% capacity factor would increase the CO emissions by 131 tons per year thereby triggering NSR.

Significant NSR pollutant increase is defined in tons/year that is equal to or exceeds the levels in the table below:

Pollutant	Significant Emission Increases t/yr.
Carbon Monoxide (CO)	100
Nitrogen Oxides (NOx)	40
Particulate Matter (PM)	25
PM_{10}	15
$PM_{2.5}$	10
Sulfur Dioxide (SO_2)	40
Volatile Organic Compounds (VOC)	40
Lead (Pb)	0.6
Fluorides (F)	3
Sulfuric Acid Mist (H_2SO_4)	7
Hydrogen Sulfide (H_2S)	10
Total Reduced Sulfur + H_2S	10
Reduced Sulfur Compounds including H_2S	10

GHG (CO_{2e})*	75,000

**if only a GHG significant increase occurs then NSR does not apply. However, if a non-GHG pollutant triggers NSR, then a significant GHG increase would trigger NSR for GHGs.*

Evaluation of Heat Rate Improvements and NSR

We believe that the NSR risk cannot be defined at this time especially as it relates to operating time. However, EPA's Integrated Planning Model (IPM) has projected that 88 GW of coal will be retired (EPA-HQ-OAR-2013-0602-0220) excluding retirements prior to 2016. EPA also projects that annual capacity factors of the surviving coal units will increase from 49% in 2012 to 54% in 2030. If a utility makes heat rate improvements or changes fuels (co-burning) and emissions of NSR pollutants are reduced and does not increase operating capacity then there should be no NSR implications. However, if the plant becomes more efficient it could change its position on the dispatch curve. If the utility increases the dispatching of the "improved" plant then there could be a NSR violation.

At the 2014 Mega Symposium, Janet McCabe, Acting Assistant Administrator, Office of Air and Radiation, U.S. EPA stated that the EPA believes, that the utility industry can meet the heat rate reductions outlined by EPA, can be achieved without triggering NSR. She also stated that the utility industry claims that many of these heat rate improvements have already implemented these improvements without triggering NSR and were implemented without permits. She added that the 6% reduction in heat rate was a "sweet spot" and can be achieved by industry. At a recent ICAC meeting with the EPA, Mr. Joseph Goffman, General Counsel for Air and Radiation, indicated that EPA's analysis showed that 8% of the plant would have an NSR issue as a result of the proposed rule regarding heat rate improvements. However, it should also be noted that as of the end of FY2013, EPA has 862 coal units under investigation for NSR violations. Additionally, EPA is not the sole entity challenging utilities. We have seen environmental groups file citizen suits against utilities separate from EPA. The ultimate decision on whether or not the heat rate improvements for NSR NOVs will be the courts. In some cases, courts have agreed with EPA's analysis, in some cases not.

EPA tried in 2002 and 2003 to clarify some of the unanswered questions regarding NSR. However, EPA's clarifications have been struck down by various courts. The 2002 rules are partly in effect in a few states; the remaining portions were struck down. The 2003 rules never went into effect and have been invalidated. Other revisions to NSR regulations were proposed in 2006 and 2007 but were never finalized, or, if finalized, EPA has stayed their effective date, is considering whether changes to the regulation are necessary, or both. Similarly, a revision finalized in December 2008 has been stayed.

The first of the revisions, published December 31, 2002 (67 Fed. Reg. 80186 [2002]), changed the rules in five ways. These changes are mainly concerned with determining whether a proposed project would "increase" emissions and with exempting from NSR some kinds of projects that were subject to NSR prior to the rule change. Portions of the 2002 rule were vacated by the D.C. Circuit Court of Appeals in New York v. EPA, 413 F.3d 3 (D.C. Cir. 2005).

EPA amended the rules again on October 27, 2003 (68 Fed. Reg. 61248 [2003]). This revision established what became known as the equipment replacement provision (ERP); it provided that some kind of replacements of equipment at existing major stationary sources would be considered routine maintenance, repair, and replacement and hence exempt from NSR. This rule never went into effect, due to a judicial stay, and was vacated by the D.C. Circuit Court of Appeals in New York v. EPA, 443 F.3d. 880 (D.C. Cir. 2006).

Historical NSR Court Cases

Further complicating the issue is that Major Modifications, RRMR&R and net increase of emissions have been subject to many interpretations and court cases. Below is a summary of two of Court cases that underlie current NSR policy interpretations.

Wisconsin Energy Corporation

In 1988 the Wisconsin Energy Corporation (WEPCo) submitted an NSR inquiry to the EPA for improvements at its Port Washington plant. The improvements included the replacement and repair of aging equipment including steam turbine generators, major boiler components and significant amounts of asbestos remediation. WEPCo initially believed that the plant, built in 1932, would not be subject to the NSR requirements and would instead fall under "routine maintenance, repair, and replacement." The EPA, however, ruled that the improvements would extend the life of the plant, and constitute a long term and significant increase in the facilities emissions, prompting WEPCo to sue the EPA in federal court.

In 1991 the Seventh Circuit Court of Appeals found that the EPA had improperly interpreted the NSR and ruled that work that "does not 'change or alter' the design or nature of the facility," would render the facility exempt from the NSR rules. Rather, it merely allows the facility to operate again as it had before the specific equipment deteriorated. The appeals court also ruled that WEPCo would not emit any more pollutants after the improvements, and agreed with WEPCo that its emissions would actually decrease and that the EPA had miscalculated its estimation of the plants emissions. However the court did agree with the EPA that the repairs and modifications to the plant did not constitute "routine maintenance." After the WEPCo ruling, the EPA continued to take a case by case approach to NSR's at facilities built before 1977, viewing the court's ruling as applying to the power sector specifically and not to all similar NSR applications in general.

Duke Energy

Between 1998 and 2000, Duke Energy made twenty nine modifications and upgrades to several of its coal-fired units. These modifications, like the ones at WEPCo, had no impact on unit emission and were designed to replace or upgrade older equipment. Duke did not apply for or obtain permits from the EPA for this work, and were sued. The EPA argued that the modifications and upgrades could significantly increase the dispatch capacity of the units, and allow them to operate at higher outputs for longer periods of time, placing Duke in excess of the EPA's Prevention of Significant Deterioration (PSD), requiring an automatic NSR.

Duke Energy initially prevailed in both the trial as well as the appeal in front of the Fourth Circuit Court of Appeals, when they ruled that the EPA's rulings were inconsistent with prior decisions and that the EPA's previous interpretation of the NSR would also have to be applied to its application of its PSD rule. The EPA, along with the North Carolina Sierra Club appealed the decision to the Supreme Court, which, in a unanimous decision, overturned the Fourth Circuit's decision. The Court ruled the term "modification" did not have the same meaning in the PSD and NSPS provisions.

Appendix B - EPA's Statistical Analysis for Building Block One

The EPA suggests that an overall average 6% improvement in heat rate of coal fired plants is achievable and cites several reports to support its conclusion. In the TSD report, the EPA indicates that the average heat rate of the ten year period between 2002 and 2012 for the over 800 units included in the data varied between 9,924 Btu/kWh and 9,643 Btu/kWh for an 11 year average of 9,754 Btu/kWh. As EPA's figure (Figure 2.1, page 2-18 EPA TSD Document) below indicates the heat rate over this period of time varied from average by approximately + 2%:

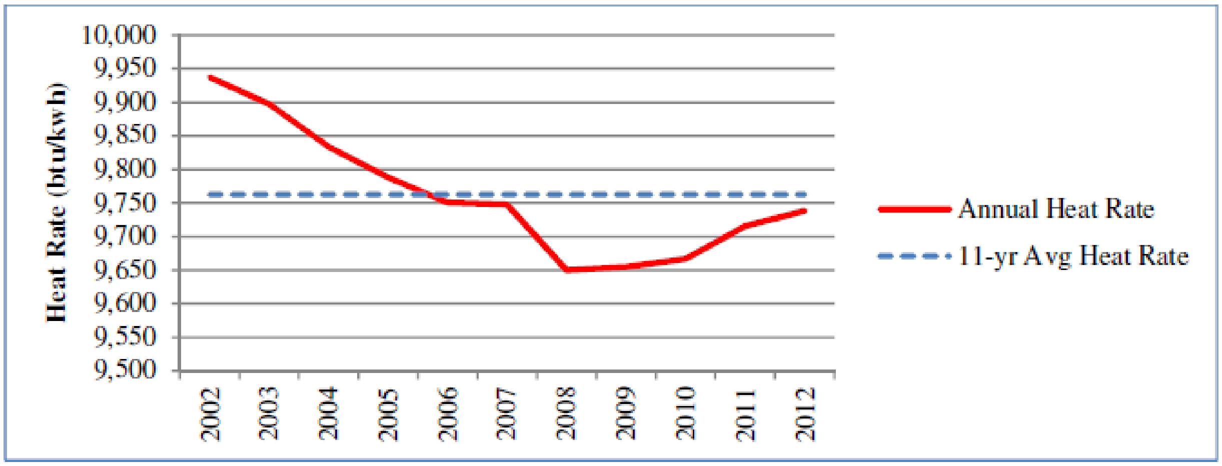


Figure 2-1. Study Population Average Gross Heat Rate by Year

The EPA concludes that the 6% improvement in heat rate can be accomplished through (a) equipment upgrades providing 2% in heat rate improvement and (b) best practices operation contributing 4% or two thirds of the proposed overall heat rate improvement.

The EPA further indicates that "capacity factor and ambient temperature accounted for" nearly a quarter (26%) "…of the change in heat rate for the study population over the study period" (page 2-24). Thus, roughly three quarters of the variability in gross heat rate was not explained by changes in capacity factor or ambient temperature. EPA concluded from its statistical analysis that a 4% improvement in heat rate was possible through improved facility controls, using no or low cost "best practices".

Regarding EPA's statistical analysis of the 4% improvement by "best practices," ICAC makes the following observations:

- First, in its statistical analysis, EPA looked at gross heat rate, when what matters for the proposed rule is net heat rate.

- Second, to support their conclusion, EPA used a statistical analysis that first presumes that a well-controlled facility using "best practices" should have a very repeatable heat rate under any given ambient temperature or hourly average load condition. EPA assumes that any variability in heat rate not explained by temperature or load is regarded as an indication that the facility operation is inconsistent and can be improved upon. EPA's analysis showed that, on average, ambient temperature and load only explained about one fourth (26%) of the variation in heat rate. This suggests one of two possibilities: 1) that there is a lot of opportunity for improvement to address the nearly three quarters of the variation not explained by temperature or load, or; 2) EPA's premise that a well-controlled facility using "best practices" should have a very repeatable heat rate under any given ambient temperature or hourly average load condition is incorrect. ICAC believes the latter explanation for the low explanatory power of temperature and load because other important factors that impact heat rate, including changes to the plants over the eleven year period such as addition of low NOx burners, addition of SCRs, soot blower controls, furnace and burner management systems, etc., were not considered in EPA's analysis. As a result of the exclusion of these and other important factors, what appears in EPA's analysis to be variability that can be better controlled is actually the result of these other effects.

In addition, the heating value of the coal consumed by the power generation industry had changed over the past few years. The following table of EIA data shows that the integrated coal used by the power industry had decreased by 2.5% which has a significant impact on plant heat rate.

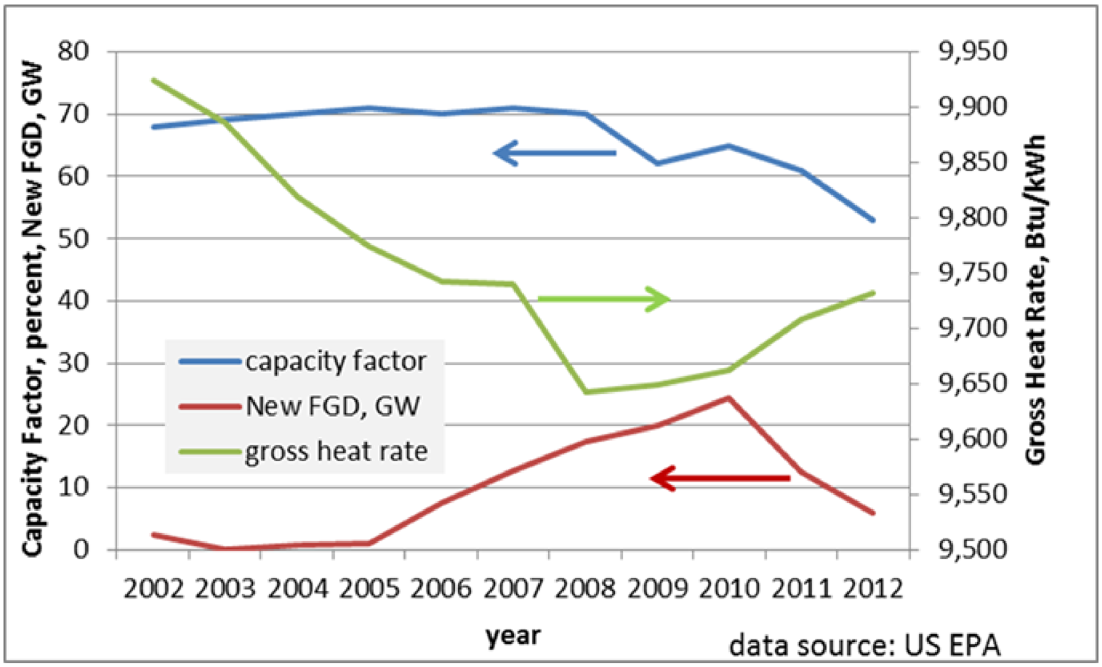
Heating Value of Coals in Electric Generation (Btu/lb)

Year	2008	2009	2010	2011	2012	2013
All coals	9,918	9,878	9,817	9,738	9,650	9,675
Lignite	6,495	6,427	6,474	6,513	6,479	6,509
Subbituminous	8,699	8,698	8,693	8,699	8,721	8,753
Bituminous	11,970	11,951	11,952	11,886	11,813	11,722

- Third, as shown in Figure 2, which displays fleet average gross heat rate and annual average capacity factor over the eleven year EPA study period, as well as data from NEEDS v5.15 showing GW of new scrubbers installed, EPA's own data shows that over the 2002-2008 period, average gross heat rate for their population decreased about 3% while capacity factor on average stayed about the same even as scrubbers were being installed. The statistical analysis performed by EPA would incorrectly identify this general improvement in heat rate over the period as variability that can be improved upon subsequent to 2012 rather than continual improvement that might not be improved upon. Beginning 2009 through 2012, the analysis demonstrates that heat rate increased about 1% while average capacity factors decreased – demonstrating the important impact of capacity factor on heat rate.

- Finally, the majority of the coal fleet already has some form of optimization software built into its controls. These optimization systems use input from hundreds of sensors in the plant to develop control algorithms used to operate the plant in a manner that optimizes the plant with respect to efficiency, reliability, safety, and environmental compliance. EPA's approach to statistically evaluating the operation of the plants against only two variables is unnecessary and too simplistic in light of the fact that many facilities already use very sophisticated systems that were tailor made to optimize that plant's operations while monitoring hundreds of sensory inputs.

Figure 2. Average Heat Rate, Average Capacity Factor, and FGD installations over the EPA study period



An article by Linn, Mastrangelo and Burtraw, funded in part by EPA and DOE, uses a similar approach. This study examined data from 1985-2009. It attempted to control for firing type, capacity and fuel type and found significant heterogeneity in the data. The heterogeneity in the data after factoring in these three technical features was evidence, they believed, that there was room to improve efficiency – by roughly 6%. They did not consider that the unexplained variation might actually be because they had not fully considered all of the key parameters beyond the facility's ability to control that impact heat rate – more than just the three parameters they considered. The authors make several errors in their analysis, among them:

- They limited the technical factors beyond the facility's control over this period to only three parameters. This is an inherently technical decision in their analysis; yet, no engineers contributed to this study. Engineers familiar with the operation of electric power plants are well aware that the factors that impact heat rate that are beyond the operator's ability to control are many more than three. This critical flaw results in them mistaking the variability in heat rate that was not explained by only three factors as opportunities to improve heat rate.

- They offer pass-through of fuel (for regulated utilities) as a reason that utilities are not motivated to improve heat rate. This ignores the fact that many coal power plants operate in deregulated markets where companies competitively bid and such pass through is not allowed, and that utilities in regulated markets can sell their power into these deregulated markets. It also dismisses the oversight role of utility commissions and the economic incentive for regulated utilities to make capital investments that benefit the consumer with lower fuel costs. Therefore, this explanation of theirs is incorrect.

- They identified how the boiler is used in the electricity system as a factor that affects heat rate that is under the control of the firm. This is fundamentally incorrect. The firm has no control over how the unit is dispatched. That is determined according to the economic order of dispatch determined by the Independent System Operator. Even vertically integrated utilities with regulated markets units must dispatch using an economic dispatch order that is beyond the plant's control.

An implied assumption made by EPA is that power plant owners are not sufficiently motivated to utilize "best practices" to reduce heat rate absent a CO_2 mitigation rule. The reasonableness of this assumption could be tested using EPA's policy analysis tools. This could be done by permitting the option of heat rate improvements when running the Base Case with the Integrated Planning Model (IPM). If running the IPM Base Case while allowing heat rate improvements results in most units applying heat rate improvements, then this will demonstrate that many of the improvements that EPA relies on for Building Block One of this rule have already been realized.

As an alternative to the methodology used by EPA, ICAC suggests evaluating historical annual average heat rates of units and, adjusting for equipment added such as scrubbers that impact heat rate and perhaps other important factors such as annual average capacity factor, use the average of the best three or four years as a heat rate going forward.

For these reasons, ICAC believes that the statistical analysis used by EPA (and that by Linn, et. al.) should not be relied upon for this rulemaking.   As a result, the conclusion drawn by EPA from this statistical analysis - that a 4% heat rate improvement is widely achievable on average through no or low cost "best practices" that improve facility control - is questionable.

Appendix C - Cost of Upgrades to Improve Heat Rate in Coal-Fired Power Plants

Air Heaters

Air heaters have been identified as one of the prime areas in coal plants that can lead to improved heat rates. There are two types of "upgrades" that EPA needs to evaluate in their rulemaking. The first type should really be considered normal maintenance and repair. In reading the Sargent &Lundy report "Coal-Fired Power Plant Heat Rate Reductions"[10] it appears that the information and heat rate improvements that are presented fall into this category. In discussions with Air Heater manufactures and companies that rebuild and maintain air heaters they all concluded that in most cases replacing circumference and radial seals, and basket replacements will only bring an existing air heater back to its original design condition. The S&L data indicated that the cost they used in this analysis is for bringing an existing air heater to design or as new condition.

To upgrade an air heater beyond its design condition is a significantly more challenging endeavor. Not all units are candidates for an upgraded design. There are several factors that need to be considered.

Design Criteria:

- Designed in concert with economizer to maximize boiler efficiency by minimizing flue gas outlet temperature from the boiler.
- Air outlet temperature set by coal drying requirements.
- Gas outlet temperature set high enough to avoid corrosion and plugging due to condensation of moisture and/or acids. Technologies such as Dry Sorbent Injection (DSI) could be used to reduce acid condensation by their application could be limited by all of the factors identified above and below.
- Pressure drop set to minimize fan power requirements.
- Gas outlet temperature needs to be high enough to support operation of Dry Scubber/Baghouse if so equipped.
- What fuel was the original design based on.

The Arvos Group - Ljungström Division (formally Alstom Air Preheater) provided an analysis of two 500 MW coal-fired units to evaluate the capabilities and cost of upgrading air heaters beyond their original design conditions. Unit specific issues can significantly affect the available results as well as the cost to upgrade any specific unit. Also note that these comparisons are based on existing equipment in **"as-new" condition** as compared to the upgrade selection also in **"as-new" condition**. If degradation of existing assets were taken into account, the value associated with these upgrades could be even more pronounced. The following analysis shows the cost and upgrade opportunities in these two plants.

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[10] "Coal-Fired Power Plant Heat Rate Reductions", Sargent & Lundy SL-009597 Final Report, Jan. 2009

Air Heater Upgrade Study for two 500 MW Coal Plants

(Arvos Group - Ljungström Division Study)

Technology	Plant A				Plant B			
	Temperature Reduction	Leakage Reduction	Fuel Reduction	Cost $ Millions	Temperature Reduction	Leakage Reduction	Fuel Reduction	Cost $ Millions
Low Impact Upgrade (Upgrade hot end element layer only)	42◦F	none	1.0-1.2%	$ 1.25	Not Applicable			
Moderate Upgrade (Upgrade all layers of element)	52◦F	none	1.3-1.4%	$ 2.45	Not Applicable			
Comprehensive Upgrade (Reconfigure APH sealing system and rotor)	64◦F	33%	1.6-1.8%	$ 10.20	8◦F	0	0	$ 10.20

The data indicate that a DSI system most likely would have to be added to the plant if it does not already have a system to control acid mist and corrosion.

Combustion Modifications

A project was undertaken by the Fuels Delivery System Subcommittee of the ASME Research Committee on Energy, Environment, and Waste (RC EEW). They evaluated a coal fired boiler group, aged 30- to 45-year old units, comprised 216 GW and 63% of the total fleet capacity with an average unit capacity of 500 MW. These units will bear the burden of ensuring the usual high standards of electric grid performance, availability, and reliability. A vital part of any coal-fired unit is the Fuel Delivery System (FDS), comprising feeders, pulverizers, classifiers, coal piping and burners. They investigated three typical 500-MW wall-, tangential-, and cyclone-, fired boilers originally designed for eastern bituminous coal and now firing low sulfur subbituminous Powder River Basin (PRB) coals. The subcommittee reviewed and selected retrofit upgrades to various parts of the FDS, determining costs and the potential value of the ensuing benefits. In the case of a 500 MW bituminous wall fired boiler they concluded that 0.34% improvement in boiler efficiency on a 500 MW wall fired coal boiler at a cost of $13,600,000.

Steam Turbine Upgrades

A recent paper was published about a plant upgrade including modifications of all sections of the steam turbine, the condenser, and the boiler. The upgrade was able to achieve a 6% plant efficiency improvement. The owners have indicated that the cost of the entire plant upgrade was in excess of $50,000,000.

Appendix D - Potential for CO_2 Emissions Reductions from Advanced Coal Plants Design

ICAC believes that the EPA could have achieved similar reductions in CO_2 emissions by encouraging the power generation industry into building new coal-fired generation that has the latest advances in thermodynamic cycle efficiency and emissions. IEA reports that the present average efficiency of the worldwide coal fleet is about 30% (11,400 BTU/KWhr). The average here in the US is slightly better at around 32% (10,700 BTU/KWhr). This includes all coal plant designs, both sub and supercritical firing and a variety of coal types from high BTU content bituminous coal to Texas and North Dakota lignite fuels. The majority of coal plants in the US were built between 1960 and 1980 and were a mix of sub and supercritical designs. The average age of coal plants in the US is now about 45 years.

Higher efficiency supercritical steam cycles became available in the 1960s. The decision as to which type of steam cycle, subcritical or the higher efficiency supercritical cycle would be used was primarily dependent on fuel cost and the risk tolerance of the user for the then new supercritical technology. While numerous supercritical plants were built in the 1960s and 1970's, operating issues and the higher maintenance expense offset the benefits of higher efficiency and subcritical designs came back in favor in the 70's.

Over the past 20 years advances in supercritical boiler designs, primarily spiral wound furnaces that allow for sliding pressure operation and improvements in boiler and combustion controls that makes operation of supercritical plants much simpler, have established supercritical designs as the choice for new plants today. Improvements in materials have allowed for increases in steam temperatures and pressures resulting in even higher plant efficiencies on the newest plants (Ultra-supercritical cycles). A consortium of US equipment manufacturers and material suppliers have for several years now been working on the development of Advanced Ultra-supercritical designs using nickel based alloys that could improve pulverized coal plant heat rates by 15% or more over Ultra-supercritical designs.

Replacing existing sub and supercritical coal plants with Ultra-supercritical plant designs would, improve plant heat rates by 5.5-16% with an equivalent reduction in CO_2 emitted per MWhr produced. Ultra-supercritical steam plants are a proven and commercially available product that can be provided by a number of boiler and steam turbine suppliers. Geographic location, fuel used and the type of condenser cooling will impact the total efficiency of any plant design but regardless of operating conditions, super or ultra-supercritical plants would still provide a significant reduction in CO_2 emissions without the use of yet-to-be-proven CO_2 capture systems.

For comparison, here are some examples of coal plant efficiencies and CO_2 emissions for a 600MW unit operating at high capacity factor, using the various steam cycle designs, firing a sub-bituminous coal with wet condenser cooling:

Plant Design	Heat Rate BTU/KWhr	Efficiency	CO_2 Emissions	Reduction in CO_2
Subcritical	10,700	32%	2105 lbs $CO_2/MWhr_{gross}$	Base
Supercritical	9500	36%	1869 lbs $CO_2/MWhr_{gross}$	11.2%
Ultra-supercritical	8979	38%	1767 lbs $CO_2/MWhr_{gross}$	16.0%
Advanced Ultra-supercritical	7500	45.5%	1476 lbs $CO_2/MWhr_{gross}$	30.0%

As indicated by the chart above, replacing sub-critical plant designs with Ultra-supercritical systems would reduce CO_2 emission by about 16%. If Advanced Ultra-supercritical plants can be commercialized an almost 30% reduction in CO_2 emissions per MWhr could be realized over subcritical plants.

China has been on a program to replace relatively new (<20 year old) subcritical plants with more efficient supercritical plants just to reduce the consumption of their very valuable coal reserves. While reducing coal consumption is an important factor in the decision to replace these older designs, CO_2 emissions as well as emissions of SOx, NOx, mercury and particulates are also reduced. China will also be commissioning Ultra-supercritical plants in the near future that will improve plant efficiency and reduce coal consumption and air emissions even further.

Replacing aging coal plants with more efficient Ultra-supercritical plants would allow for a significant reduction in CO_2 emissions from the power generation sector. These plant designs are commercially available today at reasonable cost. These designs could be deployed in a CO_2 capture ready condition. We can reduce CO_2 emission now while we wait for cost effective CO_2 capture technologies to be developed. Given the present cost to capture CO_2 no new coal plants will be built if CO_2 capture is a requirement. This valuable energy resource, coal, will be lost or exported to other countries where it will likely be used in much less efficient and less environmentally friendly plant designs. If we are truly interested in our energy security and independence from foreign energy sources we cannot abandon coal as a power generation option.

Appendix E - Other Emerging Technologies Supporting Lower CO_{2e} Emissions

If there was a strong and predictable carbon price as part of this plan to reform the energy industry sending strong signals throughout the economy that would encourage investment in alternative controls for CO_{2e} emissions. There are many technologies that can be deployed immediately and start capturing the benefits of lower GHG emissions far sooner than for other technologies. ICAC member companies are working on many emerging technologies that will greatly benefit the mission of lowering CO_{2e} emissions. As states evaluate what technologies can be used to mitigate CO_{2e} emissions as described in the Clean Power Plan, it is important that these technologies become an integral part of the state's strategies to meet their requirements. Most importantly, many of the technologies being developed would support more economical offset of power plant emissions if control through beyond the fence line controls could be implemented. Examples of the technologies being develop by ICAC member companies include:

- Methane has a Global Warming Potential (GWP) 21 times that of CO_2. Methane from coal mine methane (CMM) and ventilation air methane (VAM) from mining operations is available. The average US coal mine shaft generates about 17,500 tons methane/year, or the equivalent of 367,000 tons of CO_2 per year. This technology has already been installed and demonstrated in the US, Australia, and China. The ICAC believes a program allowing utilities to offset emissions by controlling other sources more cost-effectively should be an integral part of any initiative for controlling CO_{2e} emissions. Since these technologies can be deployed immediately and more cost-effectively than CCS/CCU technology, greater CO_{2e} emission reductions can be achieved much sooner and cheaper.

- Vent gas control from oil and gas field operations. Methane emissions from venting, if it is being controlled, employ flaring, green completion, and other emerging technologies.

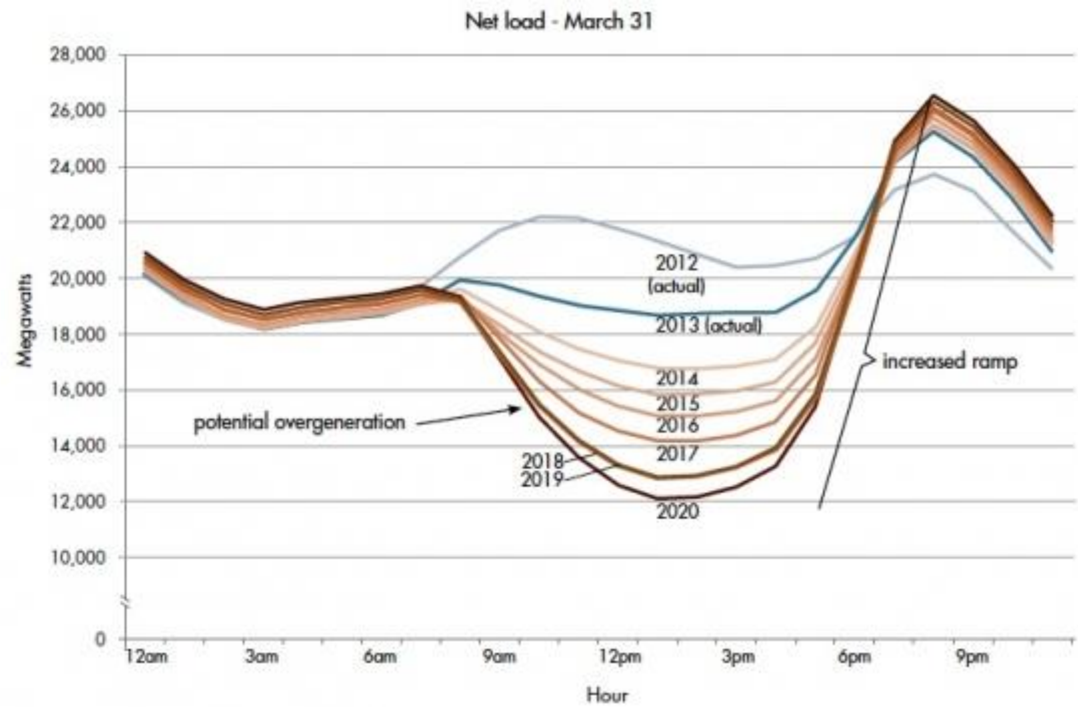
- Nitrous Oxide emission control is now being deployed in a wide range of industries (such as nitric acid, chemical process industries, adipic acid) around the world in response to the UN Clean Development mechanism. Several technologies exist depending on the temperature and application conditions, and many applications could install this technology today if a market mechanism was in place to monetize emission reductions. As N_2O is more than 300 times more potent than CO_2 as a GHG, its' control is significantly more cost-effective than any other CO_2 control technology. With the ability of energy industries to use these technologies through a mechanism similar to the very successful CDM, CO_{2e} reduction can be deployed sooner, cheaper, and with greater impact.

- Ambient capture of CO_2 for commercial use is an emerging technology that at this time is only just being scaled up to commercial scale. Several technologies are being investigated that have potential for CCU for many applications, including algae production, EOR, and feedstock. Although full scale demonstration is only just being implemented, it is one example of how new technologies can and should be encouraged to offset emissions from power generation if there was in place a mechanism to monetize CO_2 capture.

Appendix F - Frequency Regulation Needed to Integrate Renewables

The National Academy of Engineers named electrification enabled by the grid the top engineering achievement of the 20th century. Increases in grid-connected renewable energy, such as wind and solar, is rapidly changing the demands on the electric grid, leading to problems with voltage, phase, and angle and affecting the quality of power provided to end users compared to base-loaded coal which provided consistent high quality power. Uses of power are also evolving to include more low power factor loads such as florescent lights and computers that require additional reactive power. Because of the interconnected grid, unintended inefficiencies can be introduced that negate some of the intended benefits from changing fuel sources or upgrading power generation equipment. Any plan targeted at reducing CO_2 must include impacts and potential improvements in the entire system.

In 2013, the California ISO (CAISO) developed projections for net load requirements from the grid as increased renewable electricity with a strong diurnal fluctuations is brought on line. The curves shown below in what is now referred to as the “duck curve” represents the resulting requirements of the grid, especially in the evening as the sun is setting, to make up generation to accommodate the evening load peak. Fossil plants are relied upon to provide the balance of the load. Coal provides inherent energy storage for weeks or months in the form of a fairly stable rock that can reliably be stored in piles at plants representing weeks to months of full-load operation providing high quality, “clean” power to the grid. Gas does not provide the storage capacity of coal, however, simple cycle and combined cycle gas power plants are more capable than coal plants of dispatching in near real time to balance system loads. The inability of coal plants to dispatch rapidly forces them to operate continuously at poor efficiency, high heat rate, and high emissions rate low loads to maintain system reserve capacity and assure power to the grid is available. Although the coal plant is required to provide consistent, stable, high quality power to maintain grid reliability, the penalty of reduced efficiency is attributed entirely to the coal plant and not to the intermittent energy source.



The inherent variability of wind and solar electricity also introduces short term grid instability including harmonic distortions, which alters the shape of the voltage waveform distributed from purely sinusoidal to a waveform with ripples at the peaks. Unwanted harmonics can cause damage to sensitive equipment, such as computers or controllers in household electronics, and excessive heating and efficiency losses in motors and compressors, such as refrigerators and air conditioners.

Reactive power, the power required to produce the magnetic fields required for operation of equipment such as AC motors and transformers and often referred to as VAR or volt-ampere reactance. Any equipment that relies on reactive power introduces inefficiencies into the system because of the inductive reactive currents that are required. The power factor of the load can be improved through devices such as capacitors, which reduces losses in the system. Harmonic distortions in the system introduced either by intermittent energy sources or by non-linear loads such as computers and many appliances add complexity to managing power factors through simple capacitors and require adding other devices such as harmonic filters, advanced control technologies, and next generation power electronics. Improving the power factor of the load and reducing harmonic disturbances can have a significant impact on overall system efficiency. The related but often ignored impact to CO_2 and the environment that should be considered is the increased waste as appliances and sensitive equipment suffer from reduced life as a result of operating with lower quality power, and the life-cycle impacts and energy requirements associated with replacing equipment.

The impact of increased variable energy sources is reducing the quality of the power on the grid, resulting in “Dirty Power” from clean fuels. A robust plan to reduce CO_2 should take a broader perspective and include unintended consequences from focusing too narrowly on generation alone. Impacts to the system, including equipment replacement resulting from operating on lower quality power must be included in the analysis of benefits included in the Clean Power Plan. To balance the system-wide impacts and relative benefits, some penalty should be assigned to intermittent energy sources that result in negative impacts on other power sources relied upon to meet net load demands, impacts on energy losses in the electric grid resulting from increased use of intermittent sources, and impacts on downstream equipment that decrease overall system efficiency and equipment life. Benefits should also be included for facility owners that invest in improving the reliability and efficiency of the entire system, resulting in a net decrease in CO_2. An example includes credits for upgrading transmission and distribution systems though the inclusion of power factor upgrading devices such as capacitors that reduce the amount of reactive power that must be transmitted throughout the system. Another example is incorporating grid-scale energy storage, especially when it can be integrated into an existing generation facility, can improve the overall heat rate of the facility through recovering inefficiencies in the form of waste heat and allowing the facility to operate more consistently at higher loads, and provide a mechanism for the facility to provide power to the grid quickly by switching from storing power to both passing generated power directly to the grid and discharging stored power. Moving the focus from only generation to the interdependence of generation on the efficiency and reliability of the system will assure that unintended consequences are minimized and net reduction in CO_2 can be achieved.