GUIDANCE ON IMPLEMENTING THE AFFORDABLE CLEAN ENERGY RULE: ENGINEERING, OPERATIONS AND COMPLIANCE CONSIDERATIONS

B&V PROJECT NO. 400396.0010 | B&V FILE NO. 28.0001

PREPARED FOR

NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION

7 FEBRUARY 2020
(Rev 1 – 14 FEBRUARY 2020)

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PURPOSE OF THIS GUIDANCE

The purpose of this document is to supplement guidance provided by the Environmental Protection Agency (EPA) in the preamble to the Affordable Clean Energy (ACE) rule and other rulemaking documents. This document is intended to assist state regulatory authorities and owners/operators in understanding the engineering, operational and compliance issues raised by the ACE rule so that they can be appropriately addressed in an approvable state plan.

This document provides:

- Engineering guidance on calculating baseline heat rates and CO_2 emission rates and incremental changes in those rates based upon a heat rate improvement;
- Engineering guidance on evaluating the seven Best System of Emission Reduction (BSER) Heat Rate Improvement (HRI) technologies identified in the ACE rule and the likely range of heat rate improvements and changes in CO_2 emission rate that may be achieved with their adoption;
- Guidance on addressing common factors that will influence the range of improvements or appropriateness of a BSER HRI technology;
- Engineering guidance on addressing uncertainties in the state plan development process;
- Guidance on setting the final lb. CO_2/MWh standard of performance in a way that should lead to an approvable state plan; and
- Guidance on available and recommended compliance flexibilities for inclusion in a state plan to minimize need for future plan revision.

When applicable, the document discusses the flexibilities that the state regulatory authority may exercise in setting the standards of performance under the rule, with citation to applicable EPA guidance.

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Glossary of Terms

BSER	Best system of emission reduction.
CFB	Circulating fluidized bed combustion.
DERATE	A reduction in unit output. Derates are reported in terms of percent (%) of peak load or in terms of net power (MW).
EAF – EQUIVALENT AVAILABILITY FACTOR	A measure indicating the amount of energy a unit is available to produce over a period of time, relative to the capacity of the unit.
EGU	Electric utility generating unit.
ESP – ELECTROSTATIC PRECIPITATOR	A particulate removal device which uses an electrostatic field as a means of removing particulate matter from a flue gas stream.
FBR – FUEL BURN RATE	The rate at which fuel must be input to a unit to sustain stable load.
HRI	Heat rate improvement.
LOI – LOSS ON IGNITION	Unburned combustibles that are typically contained in the fly ash, bottom ash, slag, and other coal combustion residuals. This is different than carbon in ash, as LOI includes all combustible components, not solely carbon.
MRR	Monitoring, reporting and recordkeeping.
NPHR – NET PLANT HEAT RATE	A measure of efficiency comparing the thermal energy required, in terms of GJ or Btu, to produce 1 kWh of net electrical energy.
PC	Pulverized coal combustion.
VFD	Variable-frequency drive.

EXECUTIVE SUMMARY

This document is designed to supplement Environmental Protection Agency (EPA) guidance on compliance with the Affordable Clean Energy (ACE) rule. It is specifically tailored to state regulatory authorities and the owners / operators of electric generation as they seek greater understanding of the rule's engineering and operational requirements and appropriately address them in state plans.

This document provides guidance on:

- Calculating baseline heat rates and carbon dioxide (CO_2) emission rates and incremental changes in those rates based upon a heat rate improvement;
- Evaluating the seven Best System of Emission Reduction (BSER) Heat Rate Improvement (HRI) technologies identified in the ACE rule and the likely range of heat rate improvements and changes in CO_2 emission rate that may be achieved by their adoption;
- Addressing common factors that will influence the range of improvements or appropriateness of a BSER HRI technology;
- Addressing uncertainties in the state plan development process;
- Setting the final CO_2/MWh standard of performance so that it leads to an approvable state plan; and
- Including available and recommended compliance flexibility in a state plan to minimize the need for future plan revision.

The document discusses the flexibilities that a state regulatory authority may exercise in setting the standards of performance under the rule, with citation to applicable EPA guidance.

The ACE rule requires each state to establish a standard of performance for designated coal-fired electric generating units by assessing applicability of the BSER HRI technologies to each unit. This is done after considering unit-specific factors and, at the state's discretion, other factors such as the remaining useful life of the facility.

In setting the standard of performance, the state regulatory authorities and owners/operators generally should first evaluate baseline historical emissions data available to them and "anticipated future operation characteristics" for the designated coal-fired electric utility generating unit (EGU). Based on these considerations, the regulator should choose the standard of performance that best fits the available data and anticipated future operation of the unit. Available options for setting standards of performance include, but are not limited to:

- Long-term emissions averaging, with efficiency decline curves built into the allowable rate over subsequent periods, as appropriate;
- A compliance bin approach, where allowable emission rates are established for certain load bins. The average actual emission rates are compared to the average of allowable emission

rates over a set averaging period, with efficiency decline curves built into the allowable emission rates established for each bin, as appropriate; and

- Periodic compliance testing at stated conditions, with applicable decline efficiency curves built into the compliance rate over subsequent periods. This could be done seasonally at different locations on a load curve or other ways as determined by the state.

Other options may also be available, depending on the circumstances of the affected EGU. The preamble to the ACE rule provides guidance on how these options may be exercised, and this document links key parts of the preamble and rule to examples from EGUs that illustrate specific issues.

Once the basic approach is established, owners / operators and state regulatory authorities must undertake five tasks to establish standards of performance and meet ACE rule requirements.

1. **Establishing baseline heat and emissions rates**. The choice of baseline heat and emission rate will be influenced by available data, projected future use of the affected coal-fired EGU, and whether the state regulatory authority desires to use continuous emissions monitoring systems (CEMS,) performance testing, or some other method for the ultimate determination of compliance with the standard of performance. When possible, baseline data should be chosen that reflects the likely future use of the designated unit or that allows technically defensible projections, if needed to meet ACE requirements. Owners/operators and state regulators should discuss the form of the standard of performance before settling on the baseline. This may require discussion between the parties *before* data are requested to ensure that data and analyses submitted support development of the final standard of performance.

2. **Reviewing BSER HRI technology.** Once the state determines the appropriate baseline, the effect of the BSER HRI technologies must be assessed to set each standard of performance to "reflect the degree of emission limitation achievable" (40 CFR 60.5735a(a)(2)) at an EGU through application of the BSER HRI technologies. Subpart UUUUa requires that each BSER HRI technology be assessed for each EGU and, if it is determined to be "applicable," that the resulting heat rate improvement, if any, should usually fall within the range identified in EPA Table 1 for that technology. If the BSER HRI technology is determined to fall outside the identified range, the basis for that determination must be documented. This guidance provides additional engineering analysis to help states understand the underlying technical issues they may face when making this determination.

3. **Evaluating degradation of BSER HRI effectiveness.** Almost all of the BSER HRI technologies are expected to have reduced effect over time. This degradation should be evaluated in setting the standard of performance or EGUs will be unable to achieve the final standard of performance over time due to the performance changes. This document

provides engineering guidance on evaluating degradation that should be expected even with proper maintenance and operating practices.

4. **Evaluating "other factors."** Subpart UUUUa allows states to consider "other factors," such as remaining useful life, cost, and site-specific issues in setting the final standard of performance (40 CFR 60.5755a(a)(2)). The guidance provides suggestions on how such consideration may be accomplished consistent with EPA practice and how to include the result in the standard of performance.

5. **Developing a final standard of performance.** The guidance summarizes the prior steps and discusses how they are integrated into a final standard of performance stated in EPA's mandated form of pounds of CO_2/MWh (which must be expressed on a net or gross basis). The guidance provides assistance in understanding pros and cons of choosing between net or gross basis. The state regulatory authority must evaluate each BSER HRI technology—and for each technology it determines is "applicable"—adjust the standard of performance to reflect application of that technology within the range established in EPA Table 1. The state regulatory authority may justify a departure from the range. The justification for change can be made individually for each technology, or once in setting the final standard of performance, but the justification must be set forth in the plan. Where there is a decline in the efficacy of the HRI technology over time, it is recommended that this decline be reflected in the standard of performance with appropriate justification in the state plan, as appropriate.

The guidance addresses the monitoring, record keeping and reporting (MRR) that EPA requires the state plan to include and provides guidelines on how they can be achieved.

Finally, the guidance discusses compliance flexibilities available to the state and recommends ways that the state plan should establish each standard of performance. The guidance further recommends ways the state regulatory authority may provide for adjustment of a standard of performance without the need for a plan revision by using applicable adjustment factors. Guidance is provided on how these adjustment factors can be developed and justified.

1.0 BACKGROUND

The National Rural Electric Cooperative Association (NRECA) assembled a task force of experts from Black & Veatch, a nationally-recognized power engineering firm, and the electric cooperative engineering and environmental fields to review the "Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units," also known as the "Affordable Clean Energy" or "ACE" rule, which was promulgated by the U.S. Environmental Protection Agency (EPA) on July 8, 2019. The task force was charged with developing guidance on engineering, operations and compliance issues in ACE that would be helpful to cooperatives, state regulatory authorities, and others in developing an approvable state plan to reduce carbon dioxide emissions from the electric utility sector, including cooperatives, in accordance with the "best system of emissions reduction" identified by the EPA in the rule.

EPA's regulations for the Adoption and Submittal of State Plans for Designated Facilities at 40 Code of Federal Regulations (CFR) Part 60, Subpart Ba, and the ACE rule (Subpart UUUUa) make clear that the EPA, states, and sources all have distinct roles, responsibilities, and flexibilities under Clean Air Act Section 111(d) in developing the state plan and the standards of performance it requires. Specifically, the EPA identifies the "best system of emissions reduction" or BSER, in this case seven heat rate improvement (HRI) technologies that states must consider; states establish standards of performance for existing sources within their jurisdiction consistent with the BSER HRI technologies they determine are applicable to each source; in determining the applicable BSER HRI technologies, states have the flexibility to consider source-specific factors, including remaining useful life; and sources then meet those standards using any combination of technologies or techniques, whether or not included in the seven BSER HRI technologies, that they believe are most appropriate for the designated EGU.

1.1 State Plan Requirements and Approvability

The minimum requirements for a state plan are set forth in 40 CFR § 60.7535a:

§60.5735a What must I include in my federally enforceable State plan?

(a) You must include the components described in paragraphs (a)(1) through (4) of this section in your plan submittal. The final plan must meet the requirements of, and include the information required under, §60.5740a.

(1) *Identification of designated facilities.* Consistent with §60.25a(a), you must identify the designated facilities covered by your plan and all designated facilities in your State that meet the applicability criteria in §60.5775a. In addition, you must include an inventory of CO_2 emissions from the designated facilities during the most recent calendar year for which data is available prior to the submission of the plan.

(2) *Standards of performance.* You must provide a standard of performance for each designated facility according to §60.5755a and compliance periods for each standard of performance according to §60.5750a. Each standard of performance must reflect the degree of

> emission limitation achievable through application of the heat rate improvements described in §60.5740a. In applying the heat rate improvements described in §60.5740a, a state may consider remaining useful life and other factors, as provided for in §60.24a(e).
>
> (3) *Identification of applicable monitoring, reporting, and recordkeeping requirements for each designated facility.* You must include in your plan all applicable monitoring, reporting and recordkeeping requirements for each designated facility and the requirements must be consistent with or no less stringent than the requirements specified in §60.5785a.
>
> (4) *State reporting.* Your plan must include a description of the process, contents, and schedule for State reporting to the EPA about plan implementation and progress, including information required under §60.5795a.
>
> (b) You must follow the requirements of subpart Ba of this part and demonstrate that they were met in your State plan.

40 C.F.R. § 60.6735a. The following sections of this guidance address the steps needed to satisfy these plan requirements.

1.2 Overview of the ACE Implementation Process

The EPA has set forth a process that it expects state regulatory authorities and owners/operators to follow. While EPA allows variance from this process, it expects the final decision to be justified in terms of how the procedure meets the goals and takes into account the considerations set forth in the EPA proposed process. Accordingly, this section of the guidance provides a brief overview of the EPA process. This overview is followed by detailed sections that presents the EPA guidance, the available flexibilities, and engineering and policy considerations in exercising those flexibilities.

As EPA states:

> [B]ased on both the mandatory and discretionary aspects of CAA section 111(d), a certain level of process is required of state plans: Namely, they must demonstrate the application of the BSER in establishing a standard of performance, and if the state chooses, the consideration of remaining useful life and other factors in applying a standard of performance to a designated facility. The EPA anticipates that states can correspondingly establish standards of performance by performing two sequential steps, or alternatively, as further described later in this section, by performing these two steps simultaneously. The two steps to establish standards of performance are: (1) reflect the degree of emission limitation achievable through application of the BSER, and, if the state chooses, (2) consider the remaining useful life and other source-specific factors.

84 Fed. Reg. at 32549.

The EPA process assumes that the states or permitting authorities will take the following steps:

- Identify the units subject to ACE.
- Establish a “baseline emission rate” that will be used as the base for calculating heat rate improvements resulting from the candidate technologies.

- Evaluate each unit subject to ACE against the seven “BSER HRI technologies” to determine the resulting “standard of performance” that the unit can achieve. In undertaking this evaluation, EPA outlines a two-step approach, although states and permitting authorities may combine these steps so long as all considerations are addressed:
  - Step One. Step One is applying each of the BSER HRI technologies to the unit. EPA believes that the BSER HRI technologies are generally applicable and has provided a “range” of heat rate improvement likely associated with each one. However, EPA also acknowledges that individual units are different and that these differences may affect both the applicability of a BSER HRI technology to a unit and the range of heat rate improvement and corresponding carbon emissions reduction, if any, that may be obtained.
    - Each BSER HRI technology must be evaluated for each unit and accepted or, if not feasible (or already implemented), the reason for rejection or limitation explained.
    - The range and most likely heat rate improvement/carbon emissions reduction for each BSER HRI technology must be identified. This discussion must include an evaluation of any loss of efficiency/effectiveness over time, which must be addressed in the final determination.
    - The overall range and most likely heat rate improvement/carbon emissions reduction for the group of selected measures, including consideration of loss of efficiency/effectiveness, must be identified for the specific unit.
  - Step Two. Unlike Step One, which is mandatory for all states and permitting authorities, Step Two is discretionary. In Step Two, a state or permitting authority may consider other factors allowed under the Clean Air Act or EPA’s implementing regulations to adjust the heat rate improvement/carbon emissions reduction arrived at in Step One.
    - EPA specifically notes that remaining useful life, excessive cost, or other site-specific factors may be considered.
    - Each factor that is considered must be addressed in the state plan and the effect of application of that factor on the BSER rate established pursuant to Step One discussed and justified.
  - At the conclusion of the two-step process (or single step process, if the state or permitting authority elects to combine all of the analysis into a single discussion), a standard of performance for each affected unit must be established in lb. CO_2/MWh, specifying either a net or gross basis.
- Once the standard of performance is set, the state must establish compliance requirements, including averaging period, testing, monitoring, recordkeeping and reporting requirements. An overview of allowable options and flexibilities is outlined in this guidance to assist cooperatives, states and permitting authorities.

- The complete package of BSER evaluation, standard of performance setting, and monitoring, recordkeeping and reporting and any compliance flexibilities included in the state program must be set forth in the implementation planning materials.

This guidance will address each of these tasks.

Implementing the ACE rule will likely be more challenging than implementing a typical air pollution control standard because there is no CO_2 removal technology that is commercially available for existing coal-fired electric utility generating units (EGUs). Instead, EPA's BSER HRI technologies upgrade ancillary or associated equipment or improve maintenance practices and may have collateral consequences that implicate process, operational and commercial concerns. This guidance will assist state regulatory authorities in understanding and addressing these concerns.

1.3 Energy Market Considerations

As state regulatory authorities develop their state plans required by the ACE rule, it is essential that they consider both the wholesale electric market conditions impacting the bulk electric system in the state and the level of dispatch control (or lack thereof) provided to the affected coal-fired EGUs within that system.

The integration of distributive generation, battery storage, and natural variations in renewable sources, natural gas pipeline congestion and transmission congestion are creating a strain on the bulk electric system. Coal-fired EGUs will continue to face a constantly-changing set of market conditions that likely will mean operating less and thereby increasing their heat rates relative to past conditions, which also will reduce the impact of the BSER HRI technologies on those units. This general trend of more varying and overall reduced dispatch will be accompanied by seasons (and years) when coal-fired EGUs will run close to design for long periods of time because of increased demand conditions in some markets. Therefore, firm seasonal or annual limitations that might account for the higher heat rate improvement due to recent reduced usage may unduly restrict operation at full design when needed to address demand growth.

For those generators who are members of a bulk electric system that is governed by a Regional Transmission Organization (RTO) and/or Independent System Operator (ISO), the system operator regulations directly impact the ability of coal-fired EGU operators to control their own dispatch decisions. This reality must be factored into how state regulatory authorities evaluate BSER HRI technologies and develop their compliance demonstration approaches. These considerations are discussed further in this guidance in their proper context to assist state regulatory authorities in understanding how these dynamic market conditions and dispatch considerations should be factored into state plan development.

For example, when assessing BSER, states regulatory authorities should consider costs based on the range of likely future operating levels and not assume 8760-hour/year operation in every instance. Use of realistic operating ranges should not unduly constrain use of EGUs that may be needed to meet critical load requirements (for example, during unusual weather patterns or outages at other units).

Also, when developing compliance demonstration approaches, states should take into consideration the fact that, as solar and wind are added, and eventually storage, there will be lower loads and more ramping of coal-fired EGUs. The impact of renewables and ramping/cycling needs to be considered in the compliance approach. EGUs will need long averaging periods or possibly seasonal limits to minimize the impact of ambient condition change and measurement error or HR determination. A multiyear summation or averaging approach may be needed. Various approaches to addressing these areas are discussed in this guidance. State regulatory authorities and owners/operators should discuss which approach best meets the likely future needs of affected units.

In developing their state plans, state regulatory authorities should consider integrating the installation and implementation of the BSER HRI technologies within the power plant's normal outage cycle. Major overhaul presents an opportunity for steam path modifications while other BSER HRI technologies are more likely to be installable during "normal" outages, recognizing that companies have different durations for "normal" outages. Such an approach reduces costs and grid disruption. While the final technologies that owners/operators install may vary from the BSER HRI technologies used to set the standard of performance, the time required to install the BSER HRI technologies provides a good estimate of the time necessary for owners/operators to make required changes, if any, to assure compliance with the final standard of performance established in the state plan.

2.0 DESIGNATED FACILITY – APPLICABILITY

Before a state regulatory authority may begin the standard of performance development process, it must first demonstrate in its plan that it has identified all designated facilities subject to the ACE rule. This section discusses how to determine the "designated facilities" subject to state plan requirements.

2.1 ACE Applicability Provisions

Sections 60.5775a and 60.5780a establish the units that must be included and the units that may be excluded from the state plan. Section 60.5775a provides:

> (a) The EGUs that must be addressed by your plan are any designated facility that commenced construction on or before January 8, 2014.
> (b) A designated facility is a steam generating unit that meets the relevant applicability conditions specified in paragraphs (b)(1) through (3) of this section, as applicable, of this section except as provided in § 60.5780a.
>
> > (1) Serves a generator connected to a utility power distribution system with a nameplate capacity greater than 25 MWnet (*i.e.,* capable of selling greater than 25 MW of electricity).
> > (2) Has a base load rating (*i.e.,* design heat input capacity) greater than 260 GJ/hr (250 MMBtu/hr) heat input of fossil fuel (either alone or in combination with any other fuel).
> > (3) Is an electric utility steam generating unit that burns coal for more than 10.0 percent of the average annual heat input during the 3 previous calendar years.

40 C.F.R. § 60.5775a. A "*Steam generating unit* means any furnace, boiler, or other device used for combusting fuel and producing steam (nuclear steam generators are not included) plus any integrated equipment that provides electricity or useful thermal output to the affected facility or auxiliary equipment." 40 CFR 60.5805a. An "electric utility steam generating unit" is not directly defined in the ACE Rule but is defined in Subpart A as "any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output and more than 25 MW electrical output to any utility power distribution system for sale." 40 C.F.R. § 60.2. Between these definitions, only units that are 25 MWnet or larger and generate power for sale through a utility power distribution system are potentially subject to ACE. *See* 40 C.F.R. § 60.5775a(b)(1).

The ACE rule excludes some potentially covered units from coverage in Section 60.5780a. The excluded units are as follows:

> (1) An EGU that is subject to subpart TTTT of this part as a result of commencing construction, reconstruction or modification after the subpart TTTT applicability date;

> (2) A steam generating unit that is subject to a federally enforceable permit limiting annual net-electric sales to one-third or less of its potential electric output, or 219,000 MWh or less;
> (3) A stationary combustion turbine that meets the definition of a simple cycle stationary combustion turbine, a combined cycle stationary combustion turbine, or a combined heat and power combustion turbine;
> (4) An IGCC unit;
> (5) A non-fossil unit (*i.e.,* a unit that is capable of combusting 50 percent or more non-fossil fuel) that has always limited the use of fossil fuels to 10 percent or less of the annual capacity factor or is subject to a federally enforceable permit limiting fossil fuel use to 10 percent or less of the annual capacity factor;
> (6) An EGU that serves a generator along with other steam generating unit(s), IGCC(s), or stationary combustion turbine(s) where the effective generation capacity (determined based on a prorated output of the base load rating of each steam generating unit, IGCC, or stationary combustion turbine) is 25 MW or less;
> (7) An EGU that is a municipal waste combustor unit that is subject to subpart Eb of this part;
> (8) An EGU that is a commercial or industrial solid waste incineration unit that is subject to subpart CCCC of this part; or
> (9) A steam generating unit that fires more than 50 percent non-fossil fuels.

40 C.F.R. § 60.5780a(a). In general, all non-electric utility units are excluded. *See* 40 C.F.R. § 60.5775a(b)(3). Similarly, all non-coal units are excluded. *Id.* Within the electric utility industry, all electric utility simple cycle, combined cycle, or combined heat and power combustion turbines and IGCC units (regardless of fuel) are excluded. *See* 40 C.F.R. § 60.5780a. Similarly, utility steam units firing less than 10% coal are excluded. *Id.*

"Federally enforceable" is not defined in the ACE rule, but in NSPS Subpart Da it is defined as "all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60 and 61, requirements with any applicable State implementation plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 51.24." 40 C.F.R. § 60.41Da. Because EPA has also been clear that conditions established in the state plan also become federally enforceable, it is likely that measures that a source proposes, and the state adopts into the state plan, to demonstrate that the source is not subject to the ACE rule, would also be appropriate. *See, e.g.,* 84 Fed. Reg. 32520, 32559 n.253.

2.2 Plan Demonstration

The state plan is required to demonstrate that it addresses all designated facilities. *See* 40 C.F.R. § 60.5735a(a)(1). Accordingly, it is recommended that the state plan list all potentially affected sources within the State. If the state plan does not address some sources (for example, some are subject to EPA or tribal jurisdiction), this should be set out and explained in the plan. Similarly, the state plan should explain how it evaluated the sources in the State, determined whether they were "designated facilities" as outlined above, and explain the State's resolution of any doubtful cases. If these steps are taken, the State should satisfy the requirements of the ACE rule and 40 C.F.R. Part 60, Subpart Ba.

3.0 BASELINE AND FUTURE HEAT AND EMISSION RATE DETERMINATION AND MEASUREMENT

One of the first tasks that states will need to complete to establish the standard of performance for an affected unit will be to establish an appropriate baseline emission rate for the unit. This task may require close coordination with the unit owner/operator. Because the BSER HRI technologies focus on heat rate, and a coal-fired unit's emission rate is directly proportional to its heat rate, this section will primarily discuss historic performance on a heat rate basis, but the ultimate standard must be set on an emission rate basis. While the concept and calculation of heat rate – the total amount of energy (Btu) consumed in producing a megawatt hour (MWh) of energy – is relatively simple, there are several nuances and complexities that must be understood in establishing an appropriate baseline heat and emission rate. Most importantly, owner/operators, and state regulatory authorities need to understand the following:

- A unit's historic heat and emission rates may not be representative of its future rates because its past operating conditions may not be representative of its future operating conditions, and
- The assumptions and operational considerations that are used in the final standard of performance must be consistent with the assumptions and operational considerations for the baseline.
- It is important to recognize while there is a relationship between heat rate and emission rate it is not a direct correlation. For example, a 2 percent heat rate improvement does not translate into an equal 2 percent emissions improvement.

This chapter will explain:

- EPA's guidance on setting baseline heat and emission rates.
- The relationship of heat rate to emission rate.
- What heat rate is and the various ways it is calculated.
- The difference between net and gross heat rate.
- Some factors that can affect a unit's heat and emissions rates.

Once these above items are understood, state regulatory authorities will be in a better position to discuss the establishment of baseline rates with the unit owner/operator.

3.1 EPA Guidance on Baseline Rates

EPA received numerous comments on this issue during ACE rule development[1], which it discussed in its Response to Comments (RTC).[2] The RTC generally responded to these comments by emphasizing that states have considerable flexibility in setting baseline emission rates.[3]

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[1] See., e.g, American Society of Mechanical Engineers, Comments to Proposed ACE Rule, at 6-7 (Oct. 31, 2018) wherein ASME commented:

> EPA needs to provide a method of determining improvements in heat rate using a meaningful baseline (pre-improvement) period. The baseline data has to account for variations in load profiles, capacity factors, and ambient conditions over the baseline period. Based on an analysis of 2107 [stet.] CAMD data, capacity factor has the largest impact on heat rate for both subcritical and supercritical units. Rank of fuel and age of the unit have less impact on heat rate. Any Heat Rate improvements must be documented under repeatable measurable means to justify their implementation and any credit for completing them and what is commonly known in the industry: "Not all Heat Rates Reported are created equal". Heat rate reporting must consider ambient conditions, loads, electric grid causes, or how the plant is dispatched.
>
> While several commenters to the EPA propose averaging based on historical data for both emission production and heat rate, it should only be considered as part of the process. This approach does not have a uniform industry-wide methodology and well-defined baseline. This type of averaging has been used by EIA whereby they have reported that coal-fired plants in the U.S. have a fleet wide average thermal efficiency of approximately 32.5% high heating value (HHV). Using this information for discussion and study is fine, however, the uncertainty in this figure is undetermined because of the disparate data sources on which these averages depend. So, using this historical data to determine actual HRI quantity or set points would not be viable to all involved. Short of correcting the performance of all plants to a universal standard, such as the ASME Performance Test Codes (PTCs), direct comparisons between heat rate claims are not possible.
>
> A major problem in the industry that impacts the ability to establish a baseline and to eventually measure future HRIs are the conflicts in various databases used by EPA and Energy Information Agency (EIA). There are differences in EPA's NEEDs model and CAMD. Appendix C highlights some conflicts between EIA and EPA databases. To review these conflicts, our committee looked at the Alabama and Arkansas (these States were randomly selected) EGUs in both databases. There are significant differences in the reported unit capacities. The difference varied between 0.8% to over 21%. The average difference in reporting for just these EGUs was 7.4%. With these conflicts it is difficult to calculate capacity factors. Both EPA and IEA [stet.] list the nameplate capacity of the Turk plant at 609 MW. The plant's owner states the nameplate capacity is 675 MWg and 650 MWn. In some cases, it appears that NEEDs used summer capacity. The Committee believes that the two Federal agencies regulating the power industry should be using the same data. Also, EIA only reports net heat rate while EPA is looking at gross heat rate.
>
> In the proposed ACE Rule, it mentions that "The U.S. fleet of existing coal-fired EGUs is a diverse group of units with unique individual characteristics designed and built to meet local and regional electricity needs over the past 100 years, with no two plants (units) being identical". It then says, "there is potential for HRIs that can improve CO_2 emission but that this potential may vary considerably at the unit level". We agree with the statement from the EPA and think the baseline should not be built on any combination of categories, like supercritical or subcritical and coal type and quality, but that the baseline should be

Consistent with the grant of flexibility to the states, the ACE rule preamble contains little specific guidance regarding calculating historical "baseline" emissions; for example, EPA contemplates some form of historic averaging or a projected emission rate under specific conditions. Specifically, EPA states:

> If a state chooses to develop standards of performance through a sequential (i.e., two step) process, the state would as the first step apply the BSER to a designated facility's emission performance (e.g., **the average emission rate from the previous three years or a projected emission rate under specific conditions such as load**) and calculate the resulting emission rate.

84 Fed. Reg. at 32550 (emphasis added). Similarly, EPA notes:

> A state may determine the most appropriate methodology to calculate a standard of performance (which for purposes of this regulation will be in the form of an emission rate, as further described in section III.F.1.c. of this preamble) by applying the BSER to a designated facility based on the characteristics of the specific source (*e.g.,* load assumptions and compliance timelines). For example, *a state can start with the average emission rate of a particular designated facility* and adjust it to reflect the application of each candidate technology and the associated emission rate reduction.[4]

In summary, based on this guidance, states regulatory authorities and affected unit owners/operators should discuss historic operating conditions and maintenance practices in determining the appropriate historic lookback period for establishing the unit's baseline emissions performance. The use of longer averaging periods (such as the 3 years cited by EPA) will help address variability. If future operations are expected to be similar to past operations, a lookback within the past 10 years for a 3-year representative period may be adequate. If future operations are expected to be similar to a particular past operating period (or tranche of periods), use of that period or periods may be appropriate with justification. EPA also allows use of projected emissions as quoted above. If future operations are substantially dissimilar, the state and owner/operator may need to consider load bins or other approaches that project likely emissions. The ultimate approach should be discussed and justified in the plan.

> created on the design of each unit, and then compensated for the age and anticipated degradation that will occur on that unit. The proposed rule cannot fit all EGUs in the same box, no matter how tightly we draw the box around a group of units.

(available at https://www.regulations.gov/contentStreamer?documentId=EPA-HQ-OAR-2017-0355-24247&attachmentNumber=1&contentType=pdf).

[2] *See, e.g.*, EPA, RTC § 5.1.1 (Comment No. 10); *see also id.* § 5.1.2 (Comment No. 23); § 5.1.1 (Comment No. 18).

[3] EPA, RTC § 5.1.1 (Response to Comment No. 19).

[4] *See id. (emphasis added).*

3.2 Calculating Net and Gross Heat and Emission Rate

Because nearly all coal-fired electric generating units are subject to the Acid Rain requirements, 40 CFR Part 75, CO_2 emissions from the units are typically measured using continuous emissions monitoring systems (CEMS). Given that the ACE rule requires states to develop a standard of performance for each affected unit in units of lbs. CO_2/MWh on a gross or net basis, it is likely that CEMS data will have some role in the establishment of the ACE standard. Thus, some understanding of CEMS data is important. Perhaps most importantly, it is imperative to understand that emission rates and heat rates as determined by CEMS are directly proportional because each is derived from the same CEMS data points and converted with a static constant factor.

The emission rate is simply defined by the following equations:

$$ERgross = \frac{CO2, lbs}{Gross\ Generation, MWh}$$

$$ERnet = \frac{CO2, lbs}{Net\ Generation, MWh}$$

For units subject to Acid Rain requirements, its hourly CO_2 emission rate (lb. CO_2/hr) is determined through its CEMS as follows[5]. A unit's CEMS extracts a representative sample of flue gas and analyzes it for the concentration of CO_2 (% volume/volume basis) in the sample. The CEMS also measures the flue gas velocity (standard feet/hr), and then converts it to volumetric flow rate (cubic feet/hr). An emission rate (lbs. CO_2/hr) is then calculated by multiplying the hourly average CO_2 percent concentration by the volumetric flow rate in that hour and converting the CO_2 from a volume basis to a mass basis. Most CEMS also track gross power generation (MW/hr), which is used to convert from a pound-per-hour emission rate to a pound-per-megawatt-hour basis. As will be discussed in Section 3.2.1, net generation is a little more challenging.

The CEMS also calculates the unit's total heat input each hour (Btu/hr) based on a "fuel factor" or "F_C-factor" that is directly applied to the volumetric CO_2 flow rate as prescribed in 40 CFR 75 Appendix F 3.3.5 as follows:

> F, Fc = a factor representing a ratio of the volume of dry flue gases generated to the caloric value of the fuel combusted (F), and a factor representing a ratio of the volume of CO_2

[5] CEMs system operations and calculations are regulated under 40 CFR Part 60 and 40 CFR Part 75. This summary is simplified to afford the reader a basic understanding. While this summary discusses measurements on a unit basis of hourly, the CEMS is typically gathering and analyzing data on a sub-minute basis, which is then averaged according to Parts 60 and 75 up to an hourly basis and recorded within the data logger for the CEMS.

generated to the calorific value of the fuel combusted (Fc), respectively. Table 1 lists the values of F and Fc for different fuels.

TABLE 1—F- AND F_c-FACTORS[1]

Fuel	F-factor (dscf/mmBtu)	F_C-factor (scf CO_2/mmBtu)
Coal (as defined by ASTM D388-99[2]):		
Anthracite	10,100	1,970
Bituminous	9,780	1,800
Subbituminous	9,820	1,840
Lignite	9,860	1,910
Petroleum Coke	9,830	1,850
Tire Derived Fuel	10,260	1,800
Oil	9,190	1,420
Gas:		
Natural gas	8,710	1,040
Propane	8,710	1,190
Butane	8,710	1,250
Wood:		
Bark	9,600	1,920
Wood residue	9,240	1,830

[1]Determined at standard conditions: 20 °C (68 °F) and 29.92 inches of mercury.
[2]Incorporated by reference under §75.6 of this part.

Because coal-fired electric generating units are required to monitor for CO_2, the F_C-Factor is used. Thus, for example, a lignite-fired unit's heat input is simply the volumetric CO_2 flow rate divided by 1,910, and its heat rate is the heat input divided by the gross or net energy production.

3.3 Heat Rate and Its Variability

Because the BSER HRI technologies are described in the ACE rule on a basis of heat rate we need to first refresh which critical plant performance metrics comprise the net plant heat rate.

The **net plant heat rate** is quite simply the total heat input required per unit of net generation, but within this simple definition there are many specific conditions and qualifiers. First, in terms of the total heat input we are referring to the total fuel heat input required, whether that fuel heat is directly released within the boiler itself, or whether the fuel heat is used in a supporting role (such as in-duct natural gas burners to preheat flue gas prior to the SCR system. Second, in terms of the net generation we are referring to the electrical power available at the plant busbar for sale or other useful purpose outside of the plant generation process itself. The difference between the net plant heat rate and the gross plant heat rate is that the **gross plant heat rate** is based on the power at the generator terminals, rather than the power that can be used by processes external to the plant.

The **net plant heat rate** can be determined by the so-called "input/output method," whereby the equation is quite simply:

$$NPHR = \frac{Total\ Fuel\ Heat\ Input, Btu/hr}{Net\ Generation, kW}$$

The resulting calculation can be simplified in mixed US-SI units of "Btu/kW*hr." or "Btu/kWh". Correspondingly, the **gross plant heat rate** is:

$$GPHR = \frac{Total\ Fuel\ Heat\ Input, Btu/hr}{Gross\ Generation, kW}$$

While technically correct, this simple form of plant heat rate equations hides the fact that the net plant heat rate is actually the product of the efficiencies of the three primary energy conversion processes within a Rankine-cycle power plant.

- Boiler efficiency, which is where fuel energy is converted to steam energy.
- Turbine efficiency, which is where steam energy is converted to electrical energy.[6]
- Electrical use efficiency, which captures the amount of electricity that the power plant consumes by its internal operations.

Thus, a better equation that illustrates these three energy conversion processes is known as the loss method equation:

$$NPHR = \frac{Net\ Turbine\ Heat\ Rate, \frac{Btu}{kW * hr}}{Boiler\ Efficiency\ (fraction) * \frac{Net\ Generation, kW}{Gross\ Generation, kW}}$$

Correspondingly, since in the gross plant heat rate we are only concerned with the gross generation, the gross plant heat rate heat loss equation is:

$$GPHR = \frac{Net\ Turbine\ Heat\ Rate, \frac{Btu}{kW * hr}}{Boiler\ Efficiency\ (fraction) * 1.0}$$

[6] Turbine efficiency also includes the efficiency losses associated with the use of steam for auxiliary operations within a plant, which can include but is not limited to such things as soot blowing, building heating, boiler feed pump operation, and/or combined heat and power.

This is important because the boiler efficiency, turbine efficiency and station electrical utilization efficiency all vary as a function of the unit load.

3.3.1 Implications of Net Versus Gross Plant Heat Rate for the Standard of Performance

The primary difference between the gross and net plant heat rate is the exclusion or inclusion of electrical use efficiency, respectively. Electrical use efficiency is calculated based on how much electricity is consumed in operating the power plant (e.g., lighting, pumps and fans), which is commonly called "station service" or "auxiliary power." Take for example the case of a unit with the following characteristics:

- Gross output: 400 MW
- Net output: 370 MW
- Net turbine heat rate: 8,000 Btu/kWh
- Boiler efficiency: 88%

By utilizing the equation in Section 3.2, the unit's net plant heat rate would be:

NPHR = 8,000 / ((88/100)*(370/400)) = 9,828 Btu/kWh

And its gross plant heat rate would be:

GPHR = 8,000 / (88/100) = 9,090 Btu/kWh

Now if we assume that this unit deploys variable frequency drives for its main fans and reduces the station service by 2 MW, then the net generation will increase at the same gross output. Thus, the new characteristics of the unit are:

NPHR = 8,000 / ((88/100)*(372/400)) = 9,775 Btu/kWh

GPHR = 8,000 / (88/100) = 9,090 Btu/kWh

In this case, the net plant heat rate has shown an improvement of 53 Btu/kWh (about 0.5%), but the gross plant heat rate reflects no such benefit. Due to the fact that the gross plant heat rate neglects changes in station service, the gross plant heat rate (or an emission rate based on gross generation) measurement may not incorporate efficiency improvements from the following BSER HRI technologies[7]:

[7] EPA acknowledges that states can set a standard of performance on a net or gross basis. However, if states choose a gross basis, it must "demonstrate how to account for emission reductions that achieved through measures that only affect the *net* energy output." 84 Fed. Reg. 32555.

- Air heater and associated duct leakage control.[8]
- Variable frequency drive (VFD) motors.
- Many improved O&M practices.
- Boiler feed pump upgrades.

The case where the gross heat rate would be the better heat rate metric for a coal-fired EGU would be where emissions controls for pollutants such as NO_X, SO_2, etc. must be installed, or upgraded on a unit to meet more stringent emission limits. Taking again our hypothetical unit, if the unit must install a selective catalytic reduction (SCR) system which requires 5 MW of additional station service, then the gross heat rate would be un-impacted – but the net heat rate would worsen from its baseline value of 9,828 Btu/kWh, to the following:

NPHR = 8,000 / ((88/100)*(365/400)) = 9,963 Btu/kWh

In other words, a 1.4% worsening of net plant heat rate. This could be problematic in cases where a unit's standard of performance was based on net measurement and an emission control addition resulted in an increased net heat rate that was not contemplated or accounted for when the standard was set.

Another factor that must be considered is the situation where multiple units exist at a plant site, yet the station auxiliary power consumption is not traced and tracked back to the actual units where the service was produced. Black & Veatch often encounters situations where all units at a plant site are in operation, all of the coal handling and ash handling equipment is considered to be powered by just one of the units, when in reality the equipment may be powered partially by all units. Thus, the simplification of assigning the equipment load to one unit effectively worsens the heat rate for that unit, while not degrading the heat rate of the other units on-site that are operating. In some cases, Black & Veatch has found that significant controls upgrades may be required in order to convert operations to a more "fair and equitable" auxiliary power consumption accounting. Yet another situation may exist where two units share a common flue gas desulfurization (FGD) scrubber, and accounting for the auxiliary power consumed by the scrubber may be problematic. This may lead to a situation where a gross heat rate measurement is preferable for a plant owner, as there would be no need to distribute the auxiliary power consumption by common systems.

3.3.2 Effect of Operating Conditions on Heat Rate

Coal-fired electrical generating units are normally most efficient (have the lowest heat rate) at full-load operation. The primary reasons for this are threefold.

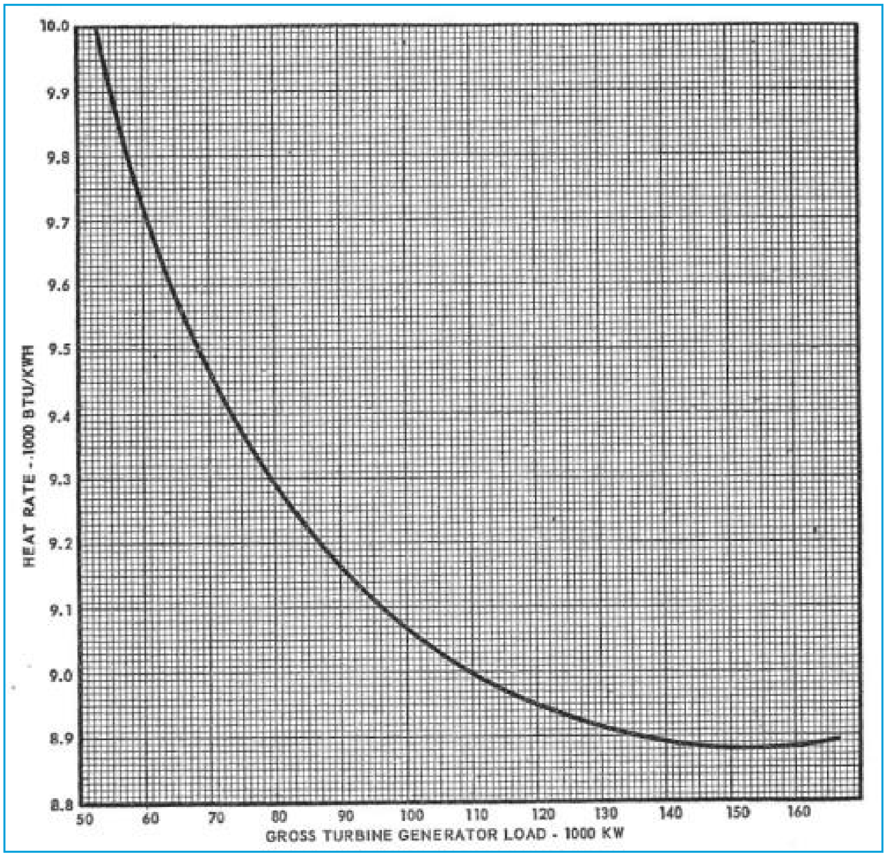
[8] One must be careful to distinguish between air heater heat transfer surface upgrades, which will primarily increase the boiler efficiency, and air heater leakage reduction, which will primarily reduce the station service. In the first case, increasing the boiler efficiency improves both the net and gross plant heat rate. In the second case, reducing the station service only improves the net plant heat rate.

1. Steam turbine generators are typically designed such that their efficiency is best at or near full-load operation of the unit. While some of this effect is due to reduced throttling losses and operating at the highest temperatures of steam produced by the boiler, it also is simply a factor of the design point of the turbine from the OEM. See Figure 3-1 for an example of a turbine heat rate curve as a function of load. On this curve, one can see that the best net turbine heat rate (NTHR) is approximately 8,800 Btu/kWh at 150 MW. By the time unit drops to 105 MW, or 70% load, the NTHR has increased (worsened) to approximately 9,040 Btu/kWh, a heat rate increase of 3%. By the time it drops to 75 MW, or 50% load, the NTHR has increased (worsened) to approximately 9,370 Btu/kWh, a heat rate increase of 6%.

2. A unit's auxiliary power consumption tends to have a base level of power required for unit operation, and with each increase in load, less auxiliary power is required per additional MW. For example, a 200 MW coal power plant may typically require approximately 5 MW of auxiliary power at its lowest-load point of 40 MW, resulting in an auxiliary power ratio of 5/40, or 12.5%. By the time the unit is at half load (100 MW) the auxiliary power will typically change to about 10 MW, or an auxiliary power ratio of 10%. By the time the unit reaches its full load of 200 MW, the auxiliary power may reach 18 MW, or an auxiliary power ratio of 9%.

3. Boiler efficiency can often be optimized at higher load points due to operator familiarity with boiler tuning, lower levels of boiler excess air, lower levels of unburned carbon and carbon monoxide (CO), and by design. This effect is less than the turbine heat rate effect.

Figure 3-1 Typical Steam Turbine Heat Rate Curve



3.3.3 Annual Unit Performance

A unit's annual net plant heat rate is driven by a multitude of factors, including the variation in ambient conditions, fuel quality, and the operations of emissions equipment at different removal rates, but on a high level it depends upon two primary factors:

- The mathematical integration of all the load points at which the unit is operated throughout the year, and
- The number of starts and stops per year.

Due to these and other factors that impact the annual net plant heat rate any attempt to predict the multitude of variables needed to predict a heat rate improvement will be fraught with uncertainties.

3.3.4 Influence of the Shape of the Load-Demand Curve on the Annual Plant Heat Rate

A unit's performance is often characterized based on its annual capacity factor on a net or gross basis. The net capacity factor is defined as simply:

$$Net\ Capacity\ Factor, \% = \frac{100 * Actual\ Annual\ Net\ Generation, MW * hr}{Unit\ Maximum\ Net\ Load, MW * 8{,}760\ hr}$$

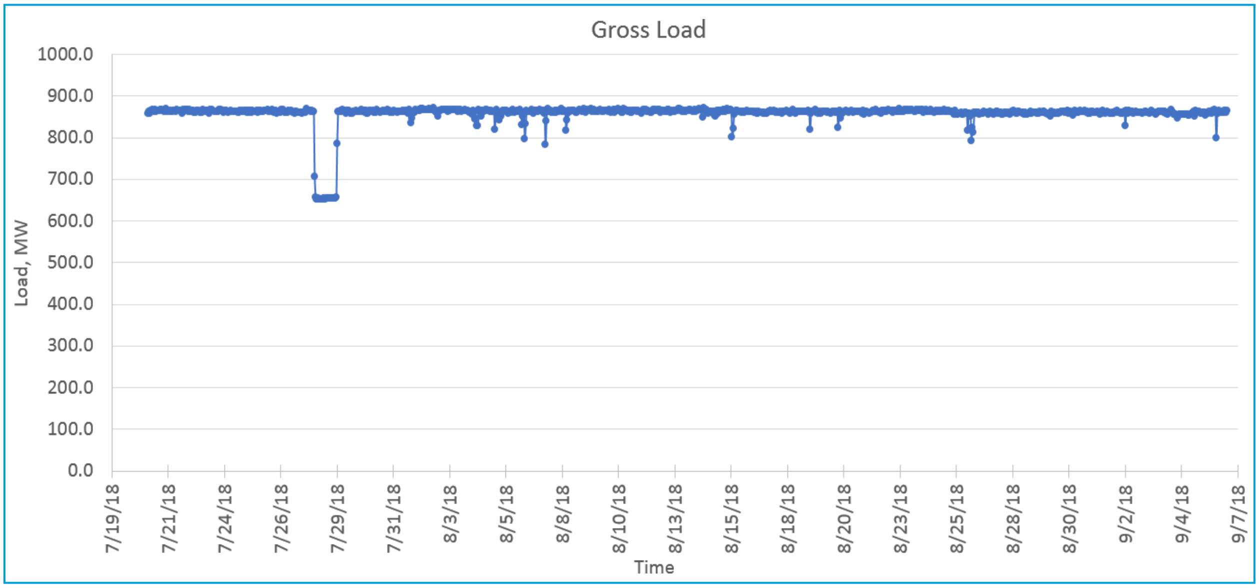
However, the net capacity factor can be misleading because it does not by itself explain how the energy was generated throughout the year, which is commonly referred to as a unit's load shape curve. If, for example, two units have the same annual capacity factor, say 50%, one cannot assume the units' operation was identical. One unit may have operated at 50% load for 8,760 hours during the year while the other unit operated at full load for 4,380 hours per year. As noted, a unit's heat rate is dependent on the mathematical integration of all of its load points and heat rates generally degrade when the units are operated at less than baseload levels. Thus, while both units had the same annual capacity factor, their annual net heat rate can be vastly different.

To illustrate the potential impacts of various operating scenarios on the net plant heat rate, Black & Veatch worked with the National Energy Technology Lab (NETL) to develop a series of charts showing the net plant heat rate using operating data from real units at 7 different load profiles. This data was drawn from a variety of units that are currently continuously monitored in the Black & Veatch ASSET360 remote monitoring and diagnostics center. All plants have been anonymized. In addition to discussing the load and heat rate variations, Black & Veatch discusses the reliability impacts of each mode of operation, as these will determine the number of starts and stops for the unit throughout the year (see Section 3.2.5). These examples should not be used in lieu of actual unit data, and the impacts on plant performance should not be construed as a surrogate for the performance of any similarly operated unit but are illustrative of the challenges that must be addressed in performing the evaluation required by the ACE rule.

3.3.4.1 Profile 1: Static Load

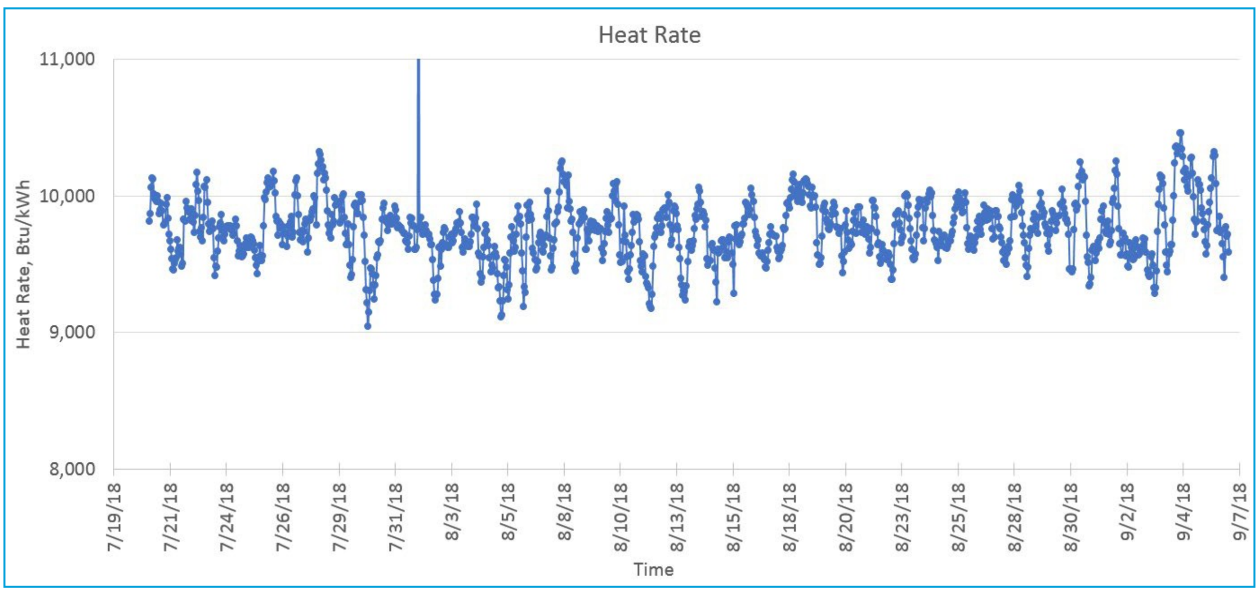
Commonly called "baseload operation," this was once considered the traditional mode of coal plant operations. Profile 1 is the design load profile for almost all coal-fired plants. When operating in this profile, O&M cost impacts are reduced relative to other profiles. The example given here is for an 860 MW nominal unit with an 85% annual net capacity factor.

Figure 3-2 Static Load Profile: Generation versus Time



When the net plant heat rate is examined over this same range, we can see that it is fairly consistent, with fluctuations being mainly due to ambient temperature variations (and the resulting variations in condenser backpressure), as well as fuel quality variations.

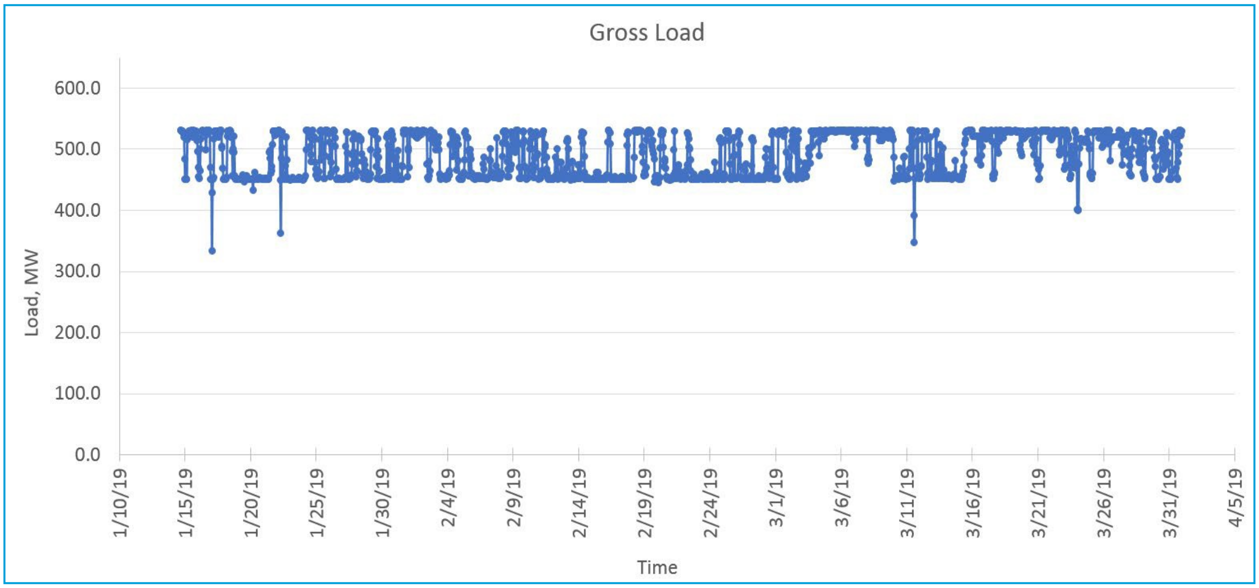
Figure 3-3 Static Load Profile: Net Plant Heat Rate versus Time



3.3.4.2 Profile 2: Limited Curtailment

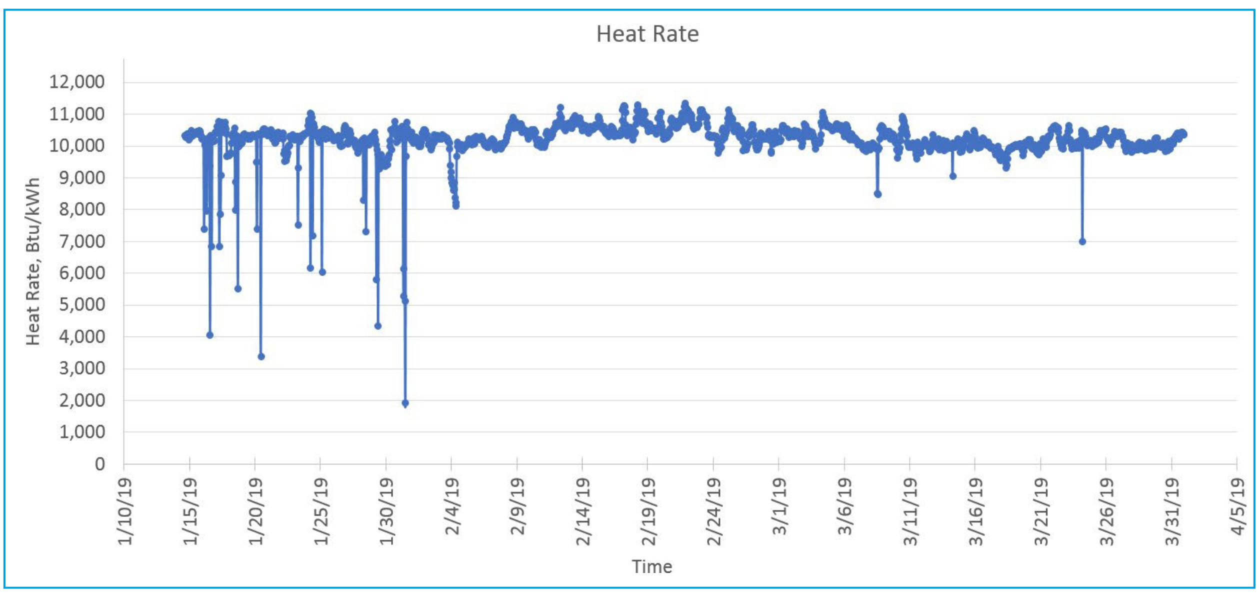
Profile 2 represents a modest amount of unit cycling, which is often on a daily or diurnal basis. The unit from which we have drawn this example is a 540 MW nominal unit with an 80% net capacity factor that operates in a competitive market with daily load fluctuations. Boiler tube failure life impacts are moderate for this unit.

Figure 3-4 Limited Curtailment Load Profile: Generation versus Time



When the net plant heat rate is examined over this same range, we can see that heat rate variations increase with this operations profile. Drop-outs in the plot are due to poor data collection from sensor failures.

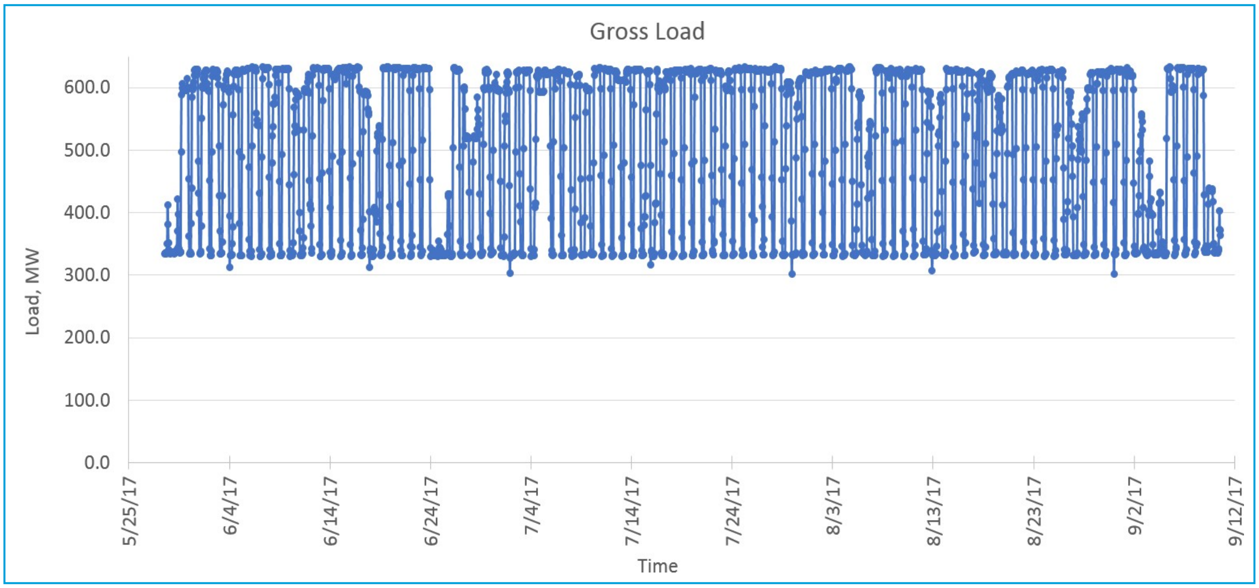
Figure 3-5 Limited Curtailment Load Profile: Net Plant Heat Rate versus Time



3.3.4.3 Profile 3: Load-Following

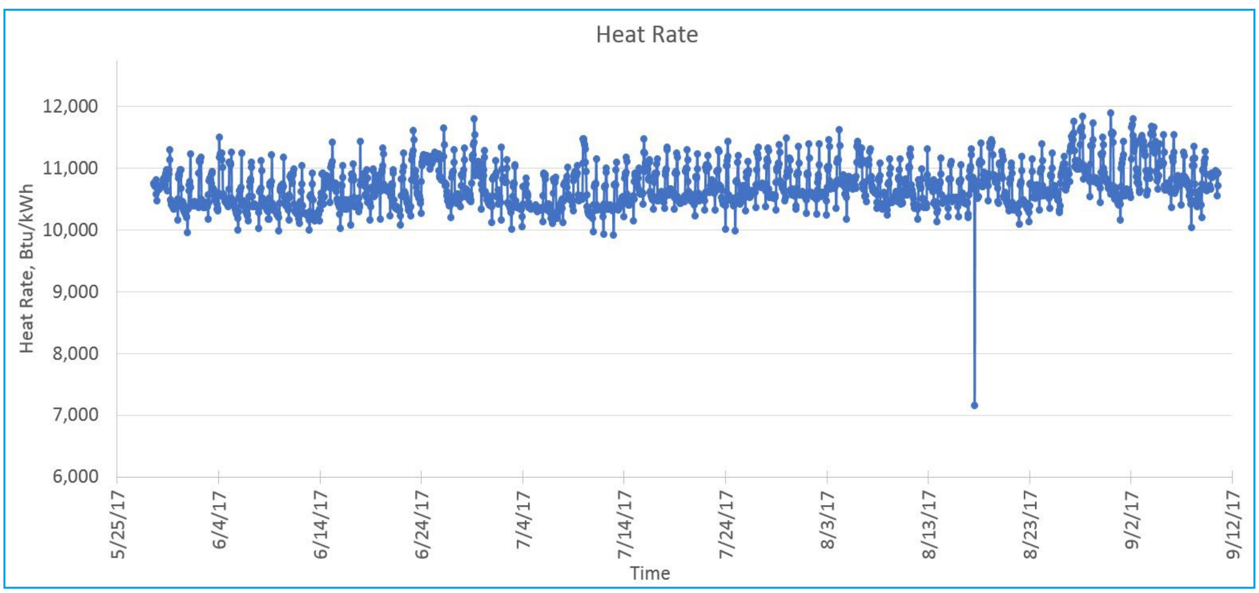
Profile 3 is a 640 MW nominal unit with an annual net capacity factor of 75%, that reduces load to 50% on a daily basis (i.e., deep cycling). Boiler tube life is significantly impacted by this mode of operations, with an equivalent availability factor (EAF) impact estimated at -2.0% in the first year, and -1.25% on a long-term basis (relative to static load).

Figure 3-6 Load-Following Load Profile: Generation versus Time



In this mode of operation, the net plant heat rate impacts are larger than the impact seen in Profile 1 or 2, with daily variations of +/- 400 Btu/kWh from the mean.

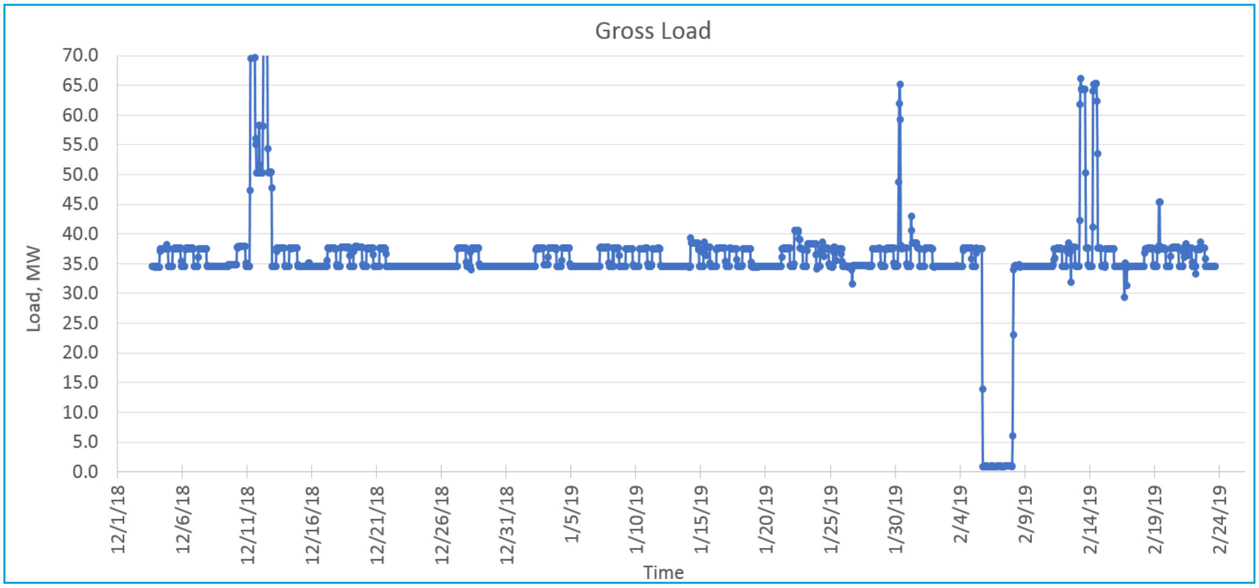
Figure 3-7 Load-Following Load Profile: Net Plant Heat Rate versus Time



3.3.4.4 Profile 4: Low-Load Dispatch

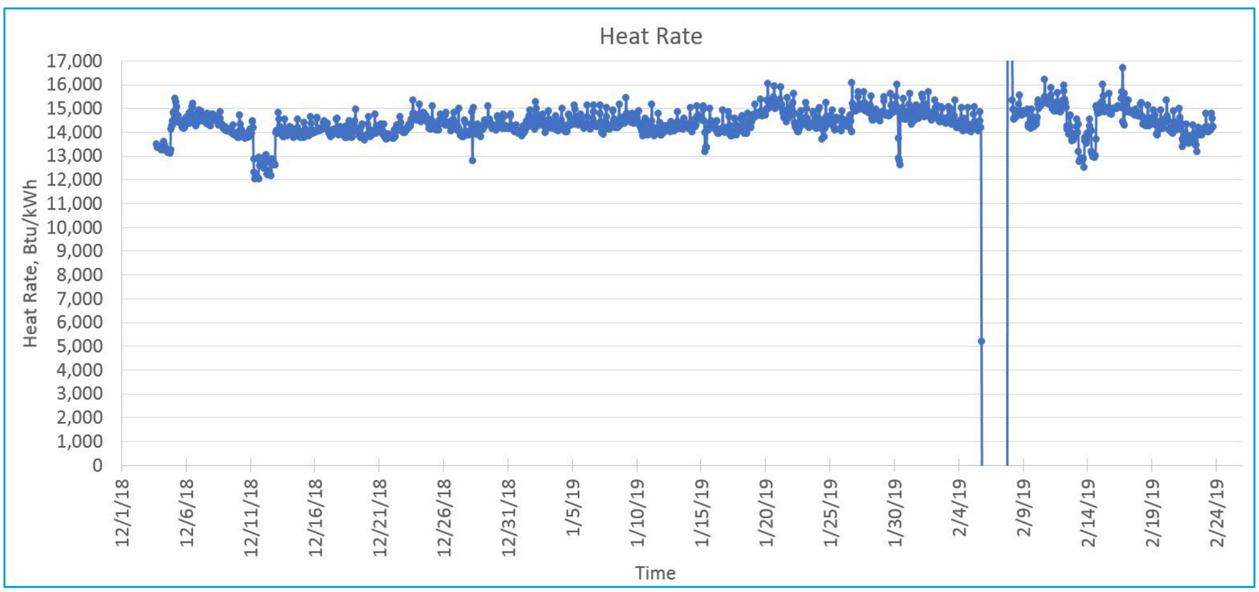
Profile 4 is a nominal 72 MW unit that is typically parked at 50% load (an effective 50% net capacity factor). Plant operations report that boiler tube life was greatly extended with this mode of operation (EAF approximately 1.5% better than with static operations).

Figure 3-8 Low-Load Dispatch Load Profile: Generation versus Time



The heat rate penalty for this unit in Profile 4 is severe relative to that at full-load, being between 2,500-3,200 Btu/kWh due to low hot reheat temperatures.

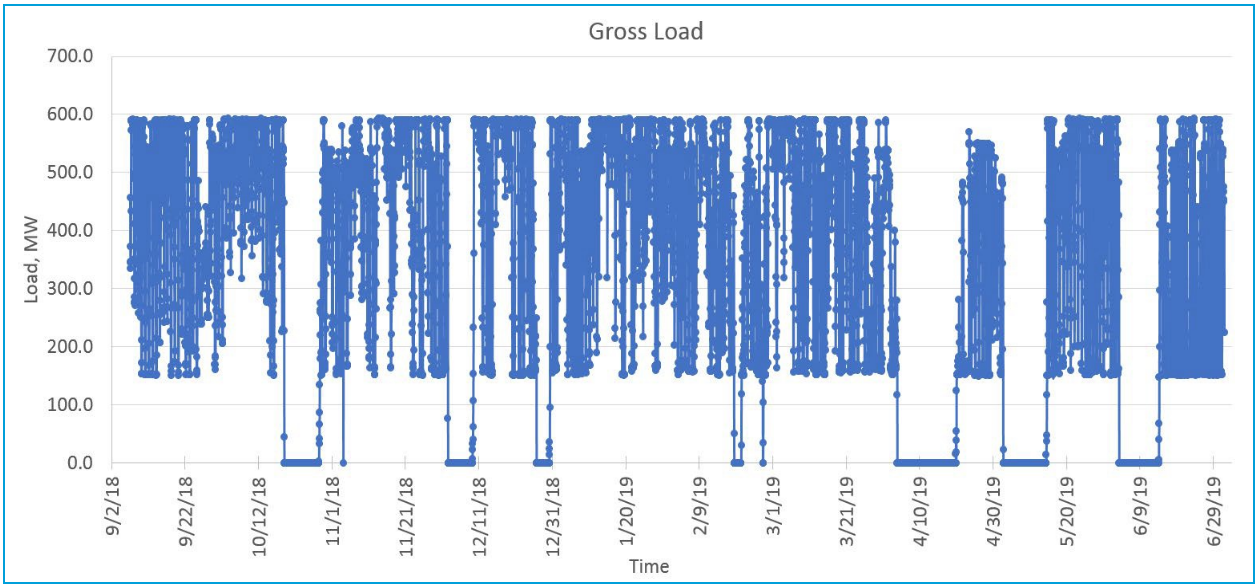
Figure 3-9 Low-Load Dispatch Load Profile: Net Plant Heat Rate versus Time



3.3.4.5 Profile 5: Infrequent Standby

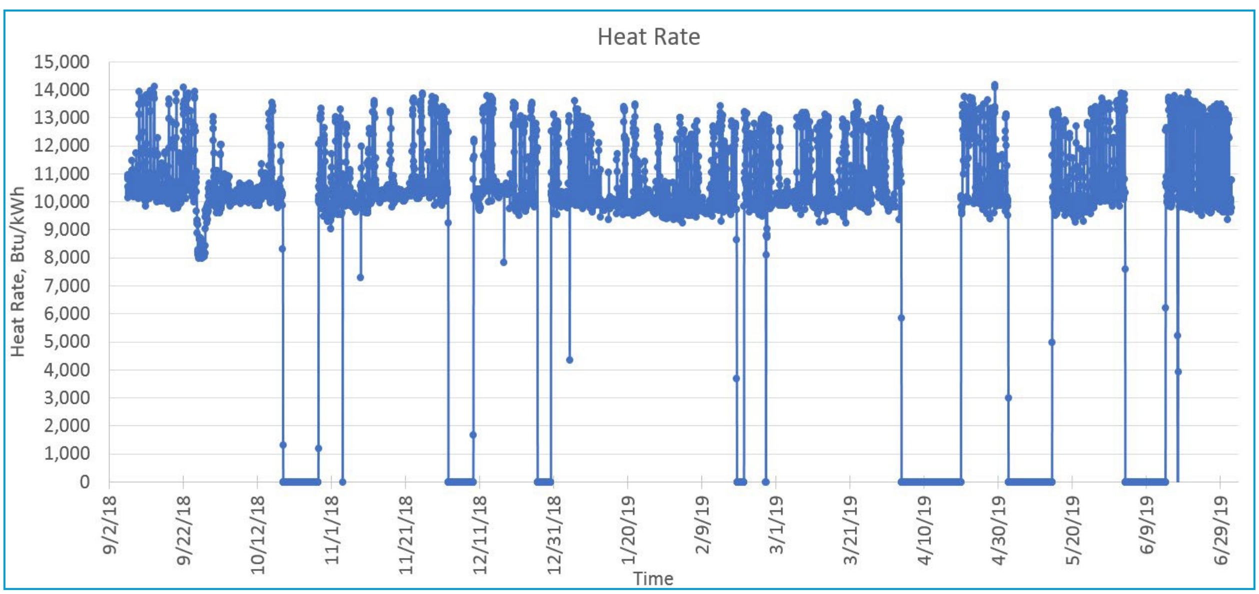
Profile 5 is a nominal 600 MW unit with a 35% annual net capacity factor. This unit typically cycles from 100% to 25% load, but also undergoes frequent planned outages due to economic reasons (7 outages in 9 months). Boiler tube life is dramatically impacted by this mode of operations, with an EAF impact estimated at -3.0% in the first year, and -1.7 to -1.9% on a long-term basis (relative to static load).

Figure 3-10 Infrequent Standby Load Profile: Generation versus Time



Heat rate impacts are severe due to cycling impacts (3,600-4,200 Btu/kWh penalty relative to static load), and higher fuel costs due to frequent cold starts.

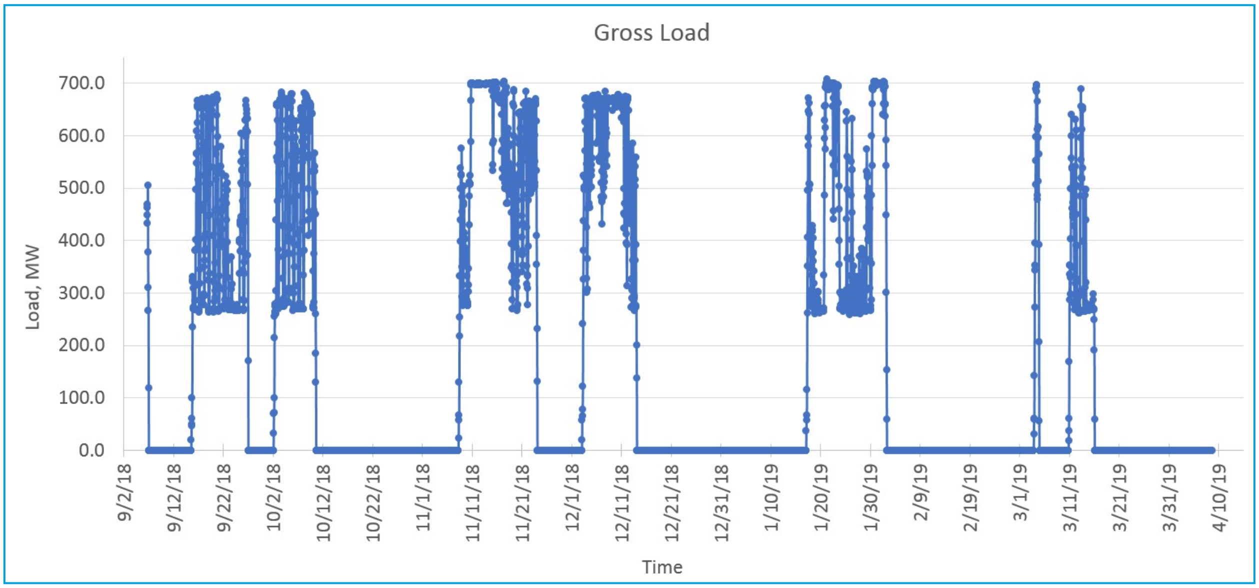
Figure 3-11 Infrequent Standby Load Profile: Net Plant Heat Rate versus Time



3.3.4.6 Profile 6: Frequent Standby

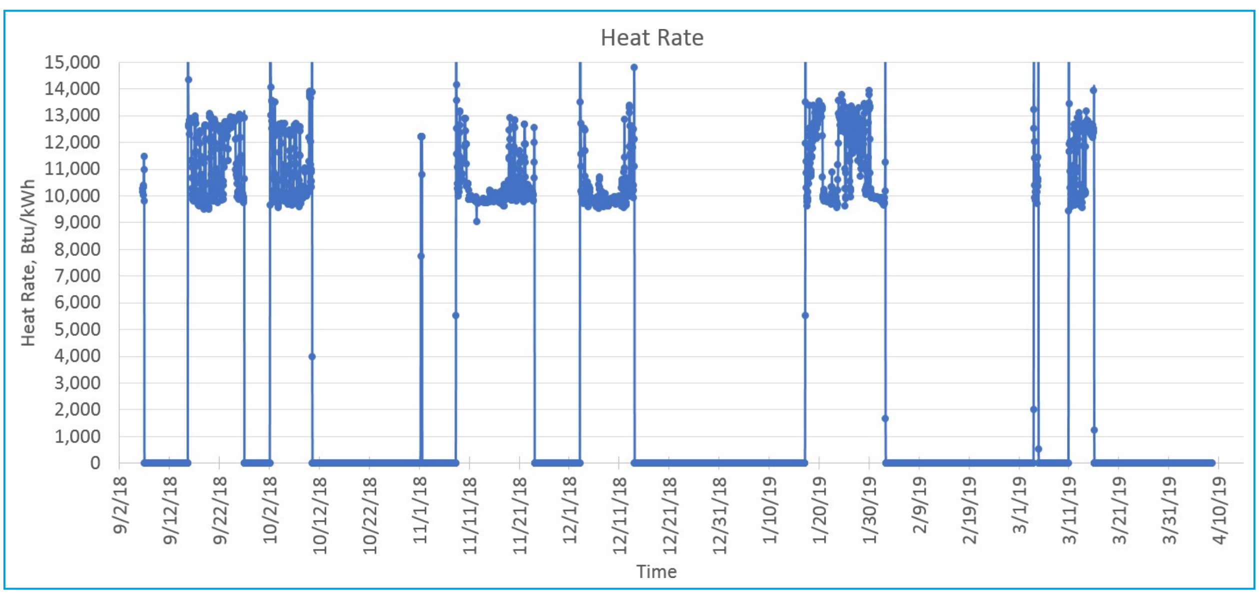
This 700 MW nominal unit demonstrated in Profile 6 not only frequently drops to 40% load, but it undergoes regular extended economic outages (1/month on average). Boiler tube life impacts are similar to the infrequent standby case (lesser cycling depth, but more cold starts). The resulting annual net capacity factor for this unit is only 15%.

Figure 3-12 Frequent Standby Load Profile: Generation versus Time



Heat rate impacts were less severe per hour operated than Profile 5, the infrequent standby case, primarily due to a higher minimum load (40%, versus 25% for the infrequent standby case). EAF impacts for this unit were only -1.5% for the first year, and -0.75% for subsequent years.

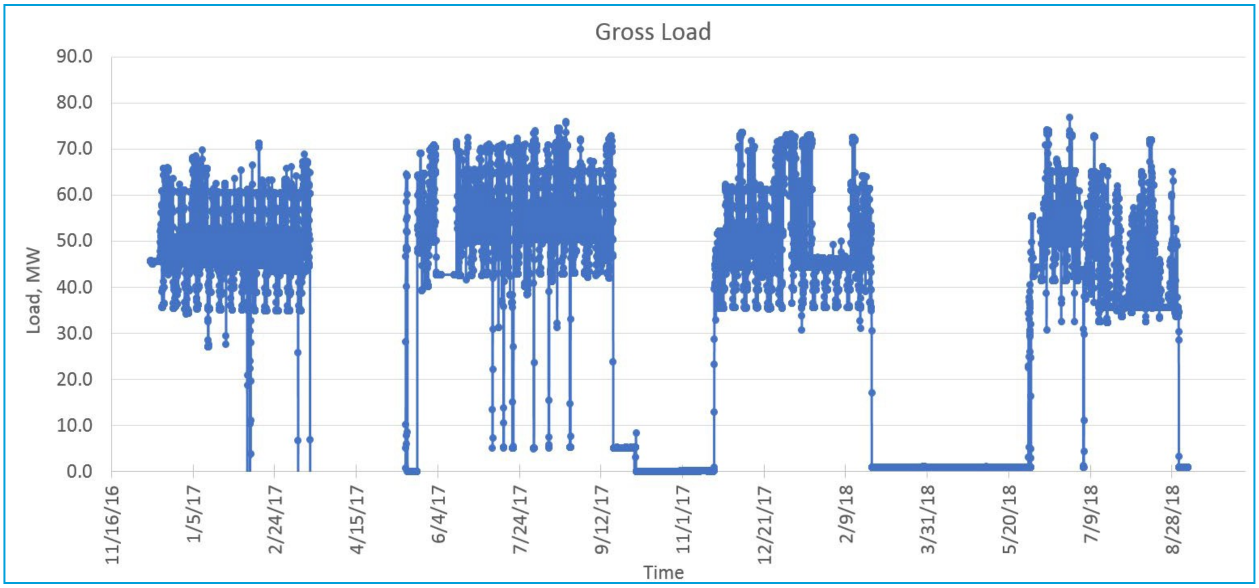
Figure 3-13 Frequent Standby Load Profile: Net Plant Heat Rate versus Time



3.3.4.7 Profile 7: Seasonal Standby

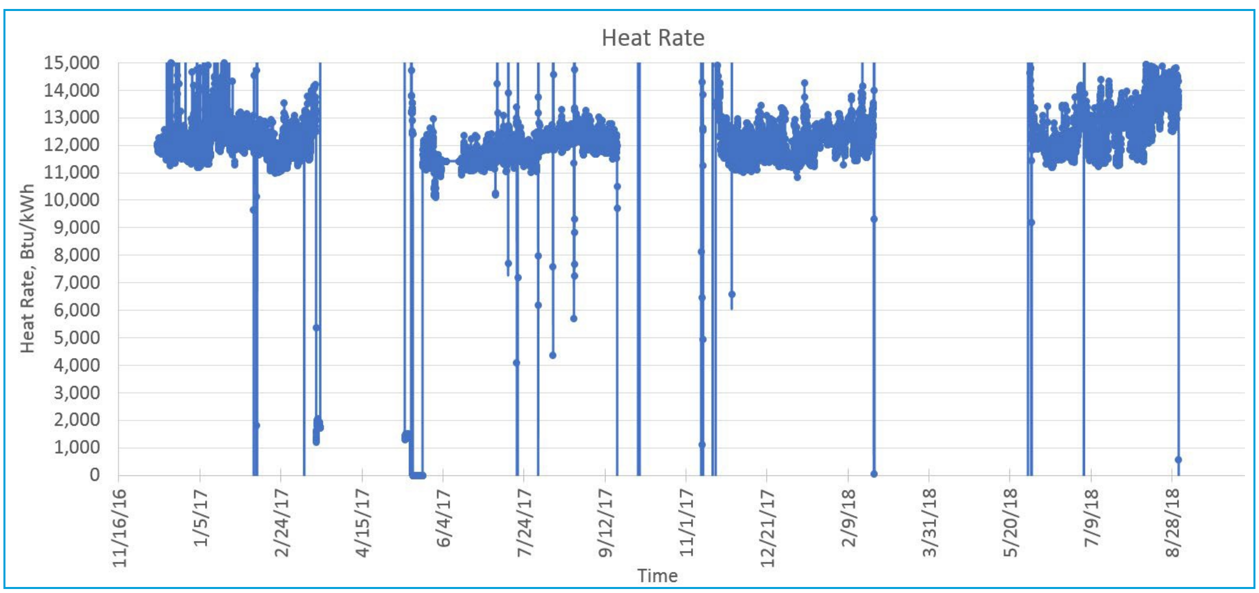
This 80 MW nominal unit achieves an annual net capacity factor of 30% despite undergoing regular seasonal shutdown. The plot in Figure 3-14 shows 1.5 years of operation with 2 spring and 1 fall economic shutdown. Between shutdowns, deep cycling occurs down to 40% load. Boiler tube life is not seriously impacted, but significant preparation is required to protect the unit during the seasonal outages, thus increasing O&M costs.

Figure 3-14 Seasonal Standby Load Profile: Generation versus Time



The heat rate plot in Figure 3-15 is noisy due to poor plant data, but overall the plant suffers a loss of more than 3,000 Btu/kWh from cycling. The limited number of cold starts helps reduce heat rate erosion.

Figure 3-15 Seasonal Standby Load Profile: Net Plant Heat Rate versus Time

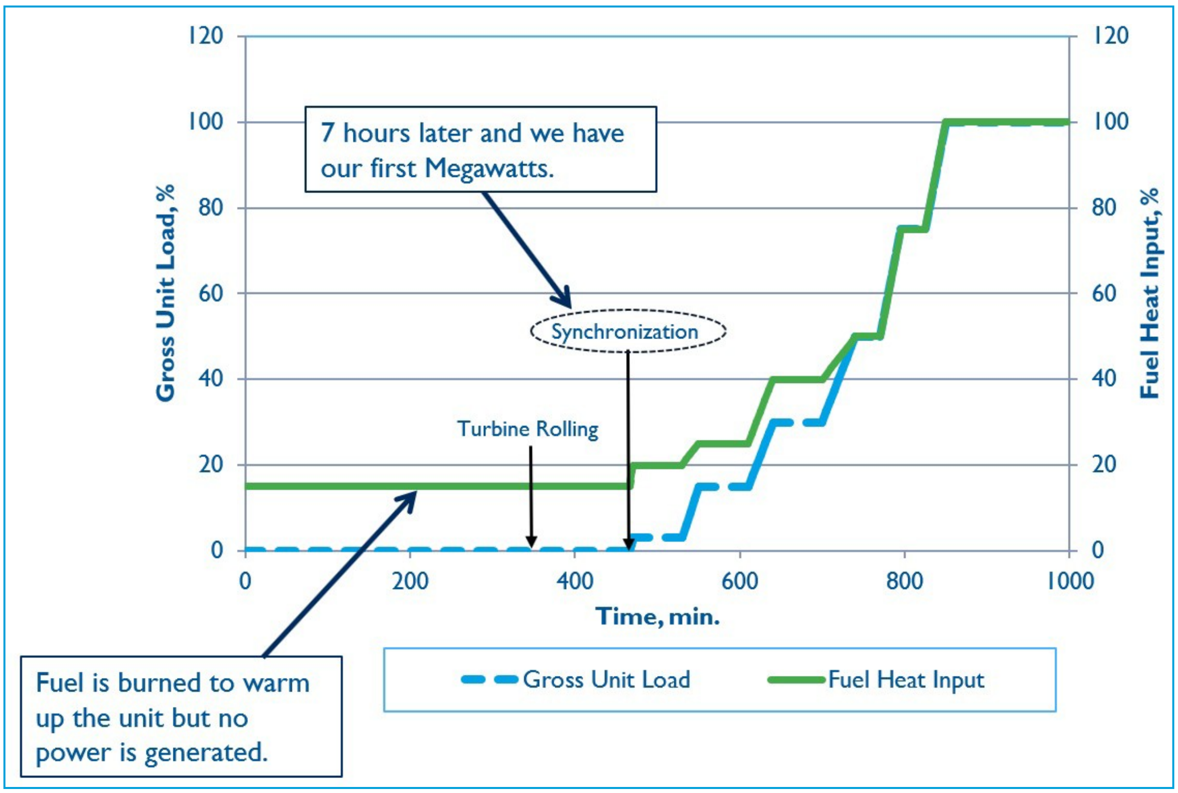


3.3.5 Influence of Starts/Stops on the Annual Plant Heat Rate

Each time a unit must be started up a significant efficiency loss is incurred. For units that operate with a good reliability factor at baseload or cycling conditions, the number of startups relative to running hours is small, so the startup penalty is relatively small over a year. In the 1980s-1990s it was common for coal-fired units in the United States to have only 3-4 cold starts per year, which were often planned and thus scheduled during times of low demand. As the market demand changed and natural gas and renewable energy competition increased, some units were required to undergo far more starts and stops due to economic reasons. In 2014 Black & Veatch worked with a coal-fired unit that was planning on at least 1 cold start every *week*, or 52 times a year.

The heat rate impacts of startup are well-understood on a general level by most plant staff, but rarely are they able to be easily quantified by staff. Figure 3-16 demonstrates graphically a typical cold start process for a coal-fired unit, along with its fuel heat input and generation.

Figure 3-16 Typical Cold Start Process for a Coal-Fired Utility Unit



To gain a better understanding of how the heat rate effects are quantified, Table 3-1 shows the results of a Black & Veatch study that was conducted on a 255 MW gross / 228 MW net unit, which used natural gas as a startup fuel. At full-load operation, this unit has a net plant rate of 10,851 Btu/kWh. For this study, the impacts of three different types of unit startup (cold, warm, and hot) were studied.

Table 3-1 Coal Plant Impacts of Different Startup Processes

PARAMETER	HOT START	WARM START	COLD START
Duration to generation, hr.	2	4	8
Duration to full load, hr.	4	7	14
Heat input with no generation, MBtu	1,344	2,688	5,376
Heat input to full load, MBtu	4,594	6,219	13,436
Average NPHR over the full startup process, Btu/kWh	16,379	20,243	20,838
Net thermal efficiency during the full startup process, %	20.8%	16.9%	16.4%
Startup fuel cost (at $3.40/MBtu)	$5,042	$10,539	$20,765

To visualize the effect of increased starts and stops on an annual basis, one can perform a simple math exercise for the same example unit with an average annual net plant heat rate of 10,851 Btu/kWh and 4 cold starts and which operates for 5,000 hours per year. Doubling the number of cold starts to 8 per year effectively means that for 56 hours a year (8 cold starts times 14 hours per cold start) the unit is now operating at an efficiency of 21,535 Btu/kWh. If 5,000 hours per year is maintained by the unit overall, then the new net plant heat rate is:

$$New\ NPHR, \frac{Btu}{kWh} = \frac{(5{,}000 - 56) * 10{,}851 \frac{Btu}{kWh} + 56 * 21{,}535 \frac{Btu}{kWh}}{5{,}000\ Hours}$$

$$New\ NPHR, \frac{Btu}{kWh} = 10{,}971 \frac{Btu}{kWh}$$

This represents a worsening of the average annual net plant heat rate by 120 Btu/kWh, or a 1.1% worsening of the heat rate. This study involved a single unit. It is unknown how representative this unit may of EGUs on the whole. There do appear to be examples of units that have longer durations required both to start generation and to reach full load. Thus, the impact of this issue for any EGU or the fleet as a whole could be markedly higher. Impacts associated with the varying number of starts could be avoided if startup periods were excluded from the compliance demonstration.

3.4 Heat Rate Measurement Uncertainty

Given that each state regulatory authority must establish a baseline for each affected unit, it is important to understand the various methods of heat rate measurement. As discussed in Section 3.2, CEMS can measure and calculate CO_2 emissions and also calculate a proportional heat rate. There are other means for measuring heat rate, which will be described in this section. However, EPA has made it clear that the standard of performance must be expressed and monitored in units of pounds of CO_2/MWh. Accordingly, compliance with the ACE standard must entail either stack testing or CEMS data to quantify the mass flow of CO_2.

In evaluation of BSER HRI technologies, owners/operators and state regulatory authorities may receive information giving heat rates determined from a variety of means. This section explains some of the common means of measurement and some of the issues that arise from their use. It is important for state regulatory authorities to understand these limitations in assessing information.

In the event that an owner/operator is interested in conducting heat rate testing, one must understand the operational situations facing typical coal-fired power plant.

3.4.1 Dedicated Heat Rate Testing

No power plant in the United States has a continuous heat rate test program. Performance testing for heat rate represents only a snapshot of conditions during the test. Because plant fuel quality, operations, equipment performance, and maintenance practices change throughout the year, so will the plant heat rate. Performance testing is often associated with full-load operation, although some testing can examine and quantify the heat rate across the entire typical load-demand curve.

A dedicated performance test is often expensive in terms of labor costs and additional testing equipment, as well as in costs such as fuel and ash quality testing, utilizing consultants for test burn planning and consultation, instrument surveys and replacement, updating or addition of instruments, validation of distributed control system (DCS) calculations, and additional safety equipment which may be installed. In the experience of Black & Veatch, a dedicated heat rate test which does not require extensive unit or fuel changes prior to the test can cost a power plant from $50,000 in the best case, to more than $500,000 (often the largest variable is the level of consultancy fees and third-party testing required). A dedicated performance test does not necessarily mean that the calculated heat rate is guaranteed to be accurate, but it typically means that whatever heat rate is calculated is likely the most accurate heat rate that can be determined at the facility.

In the experience of Black & Veatch, a dedicated heat rate test which employ a properly validated process that follows industry standard performance test codes, and which employs the correct and sufficient testing equipment and laboratory tests, can have an accuracy of +/- 1% or better at set operating conditions. This begs the question of course as to how one can measure small changes in the heat rate if the accuracy is only +/- 1%. The answer is that typically the problem is one of bias, rather than precision. What is important is that in order to achieve a high degree of accuracy any dedicated heat rate test at a coal-fired unit must possess:

- A properly detailed test burn plan, which includes a clear set of goals, division of responsibilities, correction factors for test conditions versus design, and which follows an industry-standard test procedure such as ASTM International's Pressure Test Code 4.1 (ASTM PTC 4.1).
- Sufficient coal and ash testing, both in terms of the tests conducted and the frequency of testing. At a minimum, the coal heating value, proximate analysis, and ultimate analysis must be analyzed, and it is recommended that composite as-burned samples be collected at the coal feeders a minimum of once every 8 hours during the test.
- Sufficient and accurate instrumentation to measure critical test conditions that will have a direct effect upon the boiler efficiency, turbine heat rate, and station auxiliary power requirements. This may include such measures as placing a grid of oxygen (O_2) sensors downstream of the economizer, obtaining accurate measurement of the boiler feedwater and cold reheat steam flows, accurate measurement of the boundary condition temperatures (air heater air inlet and air heater gas outlet temperatures, etc.
- Proper calibration of coal feeders and scales, and for scales and gravimetric feeders performing both static and dynamic load testing.

3.4.2 Heat Rate Calculation by Online Performance Monitoring

Utilizing calculations based upon the inputs from continuous performance monitoring is likely the next-most accurate method of obtaining an estimate of net plant heat rate. However, here there can be significant problems that arise due to instrumentation errors, coal feeder drift, and often a lack of correlation of the online metrics with any fuel or ash quality data. In addition to this, sometimes a DCS will contain several different methods and metrics to determine the net plant heat rate, often with no documentation existing to explain the calculation methodology or the reasons why one would choose one metric over another metric.

For one series of detailed test burns at a unit less than 10 years old where Black & Veatch was the management consultant, it was discovered that there were 8 different net plant heat rate metrics displayed to the plant operators and engineers. Relative to the mean value of the 8 points, the calculated values for the net plant heat rate ranged from -1.4% to +1.6% of the mean value. However, it was discovered that over a long-term analysis of 2 years of data, the bias between the 8 metrics was fairly consistent (barring 2 metrics where sensor upgrades occurred during the 2-year period). Thus, it was determined that while the absolute value of the actual net plant heat rate was in question, the change in the net plant heat rate could be determined at a greater level of accuracy. For this case, it appeared that changes in the net plant heat rate could be consistently detected at values greater than 0.2%.

Another surprising finding is that many critical performance metrics are not monitored in any way at some power plants. Important ambient conditions such as the relative humidity and ambient atmospheric pressure are often not monitored (with plant staff preferring to take conditions from nearby weather stations or the nearest airport). Air heater leakage is only rarely monitored in real-time, and critical flow measurements like cold reheat steam are almost never monitored. If there is any desire to utilize online performance data to determine the net plant heat rate, these data omissions must be remedied and their costs should be factored into the BSER HRI cost-effectiveness determination.

3.4.3 Heat Rate Calculation by CEMS

Utilizing the plant CEMS to determine CO_2 emission rate or heat rate is on its face desirable, as the systems are already in place at all affected power plants. The accuracy of measuring the net plant heat rate by use of CEMS is largely dependent upon the ability of the CEMS to measure specific variables: the CO_2 concentration and the total flue gas volumetric flow rate. However, as both the coal burn rate and the carbon content of the coal will influence these CEMS measurements, any test plan to measure heat rate by CEMS must also include improved coal quality testing. Still another problem with CEMS measurements involves the amount of air inleakage into the flue gas stream. Air inleakage can occur at virtually anywhere in the flow path of the flue gas, with most of the leakage occurring at the air heater and ductwork at the inlet and outlet of the particulate control device.

Another consideration is the problem of units that employ a common stack, whereby determining the heat rate and volumetric flow of each unit may be difficult to impossible. Accounting for this situation would require creative solutions, as it is highly unlikely that any plant will wish to construct a new stack to comply with heat rate measurement requirements.

Another consideration for those wishing to utilize CEMS for CO_2 emissions or heat rate measurement is that the ACE rule is a Part 60 rule, and all Part 60 rules work with unbiased data, while the CO_2 CEMS are typically installed pursuant to Part 75 and may be bias adjusted.

As CEMS systems typically have a high uncertainly level, they may struggle to find small changes in heat rate. Testing by EPRI in 2014 at a 350 MW unit[9] found that CEMS error was greater than 5%, compared to an estimated error of only 0.29% using the ASTM PTC 4.1 testing method. While it is possible that a freshly-calibrated CEMS system (such as during a relative accuracy test audit (RATA)) could yield much better results, on an annual basis the CEMS accuracy would very rapidly drift from the ideal calibration.

[9] Korellis, Sam and Dene, Chuck "Evaluating the Use of CEMS for Accurate Heat Rate Monitoring and Reporting" *POWER Online*, 2016 July.

3.4.4 Other Heat Rate Estimation Methods

Other heat rate estimation methods are even poorer in accuracy and repeatability than the aforementioned ones. One method which is still employed to this day is simply tracking coal receipts over each month, making geometric estimates of the change in the size and shape of the coal stockpile, and then estimating the coal burn rate on a monthly basis. In some cases, the only way the coal stockpile size is estimated is by aerial photography. Methods such as these cannot be expected to result in an accuracy or repeatability with less than 5-10% error.

3.4.5 Summary

As noted in Section 3.4.2, instrument selection may greatly affect measured values. Accordingly, it is critical that the same heat rate calculation methodology be used, to the extent possible, in determining the baseline emission rate, the likely effect of the BSER HRI technologies, and for the ultimate demonstration of compliance with the standard of performance emission rate. This step will reduce some of the uncertainty. If it is necessary to shift among measurement techniques, the owner/operator, state and permitting authority will need to address the effect of changing calculation methodologies on the final standard of performance.,

3.5 Post-HRI Heat and Emission Rate Measurement

Measurement of heat or emission rate subsequent to any plant upgrade is fraught with the same potential uncertainties and error as measurement prior to the upgrade, but with the added risk factor of the post-upgrade testing resulting in a finding of no change – or even worse, a degradation. As was discussed earlier with respect to maintaining recordkeeping for developing correction factors, plant staff must be diligent in tracking issues with a significant potential for impacting measurement, such as:

- Upgrades to instrumentation or controls that could impact measurement.
- Changes in fuel quality and ensuring that proper as-burned fuel testing is incorporated.
- Potential changes in boiler losses such as loss on ignition (LOI), radiation and convection, boiler air inleakage, etc. that may be different.
- Ambient temperature conditions.
- Plant equipment condition.
- Changes to or additions of plant equipment.
- Experience level of the plant staff conducting testing.
- Changing any third-party testers or consultants from the initial assessment activities.
- Other uncontrollable variables.

4.0 ESTABLISHING THE BSER HRI TECHNOLOGY HEAT AND EMISSION RATE – EPA "STEP ONE" REVIEW

The first step in EPA's proposed "two step" approach is to evaluate the heat rate improvement that would occur from implementation of the specific HRI technologies included in EPA's BSER determination. After consideration of "other factors" in Step 2, if any, this information will be used to calculate a final standard of performance in lbs. CO_2/MWh on either a gross or net basis.

4.1 EPA Guidance on Required Elements

Section 111(d) requires that the EPA Administrator prescribe regulations which establish a procedure under which each State must submit a State plan that establishes standards of performance for existing stationary sources that fall into specific categories of sources and pollutants.[10] EPA has determined that existing EGUs are a category of sources that must be regulated under Section 111 and that CO_2 is a pollutant that must be regulated under Section 111(d). 40 CFR Subpart Ba (40 CFR §§ 60.20a-60.29a) and 40 CFR Subpart UUUUa (40 CFR §§ 60.5700a-60.5805a, a/k/a "the ACE rule") prescribe the procedure and guidance under which each State must submit a State plan that establishes standards of performance for CO_2 emissions from existing EGUs.

40 CFR §§ 60.5740a(a)(1-2) and 60.5755(a)(1-2) together set forth the essential requirements for performing step one of the analysis:

> (a) In addition to the components of the plan listed in § 60.5735a, a state plan submittal to the EPA must include the information in paragraphs (a)(1) through (8) of this section. This information must be submitted to the EPA as part of your plan submittal but will not be codified as part of the federally enforceable plan upon approval by EPA.
>
> (1) You must include a summary of how you determined each standard of performance for each designated facility according to § 60.5755a(a). You must include in the summary an evaluation of the applicability of each of the following heat rate improvements to each designated facility:
>
> (i) Neural network/intelligent sootblowers;
> (ii) Boiler feed pumps;
> (iii) Air heater and duct leakage control;
> (iv) Variable frequency drives;
> (v) Blade path upgrades for steam turbines;
> (vi) Redesign or replacement of economizer; and
> (vii) Improved operating and maintenance practices.
>
> (2)(i) As part of the summary under paragraph (a)(1) of this section regarding the applicability of each heat rate improvement to each designated facility, you must include an

[10] CAA §111(d)(1), 42 USCA § 7411(d)(1).

evaluation of the following degree of emission limitation achievable through application of the heat rate improvements:

EPA Table 1 to Paragraph (a)(2)(i)—Most Impactful HRI Measures and Range of Their HRI Potential (%) by EGU Size						
HRI Measure	< 200 MW		200-500 MW		>500 MW	
	Min	Max	Min	Max	Min	Max
Neural Network/Intelligent Sootblowers	0.5	1.4	0.3	1.0	0.3	0.9
Boiler Feed Pumps	0.2	0.5	0.2	0.5	0.2	0.5
Air Heater & Duct Leakage Control	0.1	0.4	0.1	0.4	0.1	0.4
Variable Frequency Drives	0.2	0.9	0.2	1.0	0.2	1.0
Blade Path Upgrade (Steam Turbine)	0.9	2.7	1.0	2.9	1.0	2.9
Redesign/Replace Economizer	0.5	0.9	0.5	1.0	0.5	1.0
Improved Operating and Maintenance (O&M) Practices	Can range from 0 to > 2.0% depending on the unit's historical O&M practices.					

40 CFR § 60.5740a(a)(1-2(i)).

(a) You must set a standard of performance for each designated facility within the state.

(1) The standard of performance must be an emission performance rate relating mass of CO_2 emitted per unit of energy (e.g. pounds of CO_2 emitted per MWh).

(2) In establishing any standard of performance, you must consider the applicability of each of the heat rate improvements and associated degree of emission limitation achievable included in § 60.5740a(a)(1) and (2) to the designated facility. You must include a demonstration in your plan submission for how you considered each heat rate improvement and associated degree of emission limitation achievable in calculating each standard of performance.

40 CFR § 60.5755a(a)(1-2).

In the preamble accompanying the ACE rule, EPA set forth its expectations for the first step of the review process as follows:

If a state chooses to develop standards of performance through a sequential (*i.e.,* two step) process, the state would as the first step apply the BSER to a designated facility's emission performance (*e.g.,* the average emission rate from the previous three years or a projected emission rate under specific conditions such as load) and calculate the resulting emission rate. In this step, states fulfill the obligation that standards of performance reflect the degree of emission limitation achievable by evaluating the applicability of each of the candidate technologies that comprise the BSER to a specific designated facility and calculating a corresponding standard of performance based on the application of all candidate technologies that the state determines are applicable to the specific designated facility. A state may determine the most appropriate methodology to calculate a standard of

> performance (which for purposes of this regulation will be in the form of an emission rate, as further described in section III.F.1.c. of this preamble) by applying the BSER to a designated facility based on the characteristics of the specific source (*e.g.,* load assumptions and compliance timelines). For example, a state can start with the average emission rate of a particular designated facility and adjust it to reflect the application of each candidate technology and the associated emission rate reduction.

84 Fed. Reg. at 32549-50.

EPA outlined its expectation that the states regulatory authorities would tailor the BSER to the specific coal-fired electric generating unit under consideration:

> When states apply the BSER's candidate technologies to a designated facility, the application of each technology and the associated degree of emission limitation achievable by such application will entail source-specific determinations. For this reason, in Table 1, the EPA provided the degree of emission limitation achievable through application of the BSER in the form of ranges, which capture the reductions and costs that the EPA expects to approximate the outcome of the application. The degree of emission limitation achievable through application of the BSER (*i.e.,* the ranges of improvements in Table 1) should be used by the states in establishing a standard of performance; however, the standard of performance calculated for a specific designated facility may ultimately reflect a degree of emission limitation achievable through application of the BSER outside of the EPA's ranges because of consideration of source-specific factors. If a state uses the sequential two-step process to establish a standard of performance, in the first step the EPA expects that the state will use the range of improvements for each candidate technology (and combinations thereof where technically feasible) to develop a standard of performance for a designated facility (the range of costs can be used in the second step which considers the remaining useful life and other factors as discussed in section III.F.1.b).
>
> The ranges of HRI in section III.E are typical of an EGU operating under normal conditions. While a source with typical operating conditions (assuming no consideration of remaining useful life or other factors) will have a standard of performance with an expected improvement in performance within the ranges in Table 1, there may be source-specific conditions that cause the actual HRI of the applied candidate technology to fall outside the range. For example, if a designated facility had installed a new boiler feed pump just prior to a state's evaluation of the designated facility, the application of that candidate technology would yield negligible improvement in the heat rate and thus the value would fall outside the ranges provided by the EPA (*i.e.,* because the technology has already been applied and the baseline emission rate reflects that).
>
> As with the application of all the candidate technologies, the state plan submission must identify:

> (1) The value of HRI (*i.e.,* the degree of emission limitation achievable through application of the BSER) for the standard of performance established for each designated facility;
> (2) the calculation/methodology used to derive such value; and
> (3) any relevant explanation of the calculation that can help the EPA to assess the plan. In explaining the value of HRI that has been calculated, if the value of the HRI falls within the range identified by the EPA for a particular candidate technology, a state may note as such as part of its explanation.
>
> If a resulting value of HRI falls outside the range provided by the EPA, the state should in its state plan submission explain why this is the case based on application of the candidate technology to a particular source.
>
> In any instance, the state plan submission must identify the value of HRI that has been calculated and the calculation used to derive the value of HRI, and explain both. The states will thus use the information provided by the EPA, but will be expected to conduct source-specific evaluations of HRI potential, technical feasibility, and applicability for each of the BSER candidate technologies. After a state applies the candidate technologies to a designated facility (*i.e.,* step one), it can consider the remaining useful life and other factors associated with the source and determine whether it is cost reasonable to actually implement that technology at the source (*i.e.,* step two). This is described in detail below in section III.F.1.b.

84 Fed. Reg. at 35250-51.

With this guidance from EPA in mind, this document provides additional engineering guidance to assist cooperatives, states and permitting authorities in applying these concepts to the specific electric generating unit. Based upon the experience of its members and their engineering consulting partners, this guidance recommends that the cost of each candidate technology (or candidate technology component) be expressed in a consistent fashion, such as $/ton of CO_2 removed or $/% HRI, to allow meaningful comparison and decision-making.

The EPA states it identified the BSER HRI technologies from a very broad list because they "were deemed to be 'most impactful' because they can be applied broadly and are expected to provide significant HRI without limitations due to geography, fuel type, etc." Within the final ACE rule, EPA has set the BSER HRI technologies which must be evaluated by the state regulatory authorities when establishing a standard of performance for each designated unit in their state plans under CAA section 111(d). These BSER HRI technologies are found in EPA Table 1, 40 C.F.R. § 60.5740a(a)(2)(i) and Table 4-1, 84 Fed. Reg. at 32537 as cited above.

EPA also specifically excluded several technologies from consideration as BSER. These include: natural gas repowering; natural gas co-firing or refueling; biomass co-firing, and carbon capture and sequestration. 84 Fed. Reg. at 32543-49 ("Systems That Were Evaluated But Are Not Part of the Final BSER").

In evaluating the BSER HRI technologies, the ACE preamble states:

> Standards of performance must be established from a unit-level evaluation of the application of the BSER and consideration of other factors at the unit level. States are in the best position to make those evaluations and to consider of other unit-specific factors, and indeed CAA section 111(d)(1) directs EPA to permit states to take such factors into consideration as they develop plans to establish performance standards for existing sources within their jurisdiction.

84 Fed. Reg. at 32556.

This emphasizes that when the impacts of a BSER HRI technology are being evaluated, the state regulatory authority must evaluate each unit individually, and making generalizations and assumptions about the applicability of a BSER HRI technology to even "sister units" is not allowed and fraught with error. For example, Black & Veatch has discovered that in many cases differences in unit design, unit operations practices, and upgrades which have been made over the life of the unit can result in differences of +/- 50% (on an absolute basis) in HRI between such "sister units."

The BSER HRI technologies consist of six primary technologies and one O&M category broken into three subparts. EPA has provided guidance neural networks and intelligent sootblowing may be evaluated separately. Accordingly, this guidance addresses the technologies separately. Black & Veatch's experience with the practical benefits of the BSER HRI technologies supports this.

4.2 Review of the BSER Technologies and Real-World Experience from 28 Heat Rate Studies

Since late 2018, Black & Veatch has conducted 28 different EPA-ACE heat rate studies. These studies provide an expanded background that show the practical impacts and limitations of the BSER HRI technologies and their application to coal power plants. These examples are illustrative of the wide variability of factors that must be considered at each designated facility, but by no means should be used at any other EGU as a guarantee of any performance, emission, cost, logistic, or other factor. As EPA discusses in the preamble, each standard of performance for each existing EGU must be based on consideration of source-specific factors.

Within these studies the heat rate improvement potential was not estimated based upon broad or generic modeling tools or industry averages, but instead was based upon actual detailed modeling of the systems. Software such as THERMOFLEX® by Thermoflow was used for steam turbine modeling, and the Electric Power Research Institute Vista program was used for modeling economizer upgrades, air heater and duct leakage improvements, excess air reduction benefits, and intelligent sootblowing impacts. All cost estimates provided in this section were developed from both recent actual plant retrofit studies and projects, as well as using proprietary cost estimation databases developed by Black & Veatch.

For each of the BSER HRI technologies discussed below, the following questions may be helpful in determining whether a BSER HRI technology should be applied to the calculation of the standard of performance for that existing EGU:

1. Does the unit currently have that particular HRI technology installed?
2. If no, then consider the following questions:
   a. Can that particular HRI technology reduce the rate of emissions in pounds of CO_2 emitted per MWh at this unit?
   b. What is the cost of installation?
   c. What is the time line for installation?
   d. Is there a reasonable method to determine what the expected benefit to the following would be, and if so what is the expected improvement:
      i. Thermal cycle efficiency (% improvement expected)?
      ii. Net plant heat rate. (% improvement expected)?
3. If the unit currently has the technology installed:
   a. Does the technology still work?
   b. When was the technology installed?
   c. What is its expected life?
   d. Was there a reasonable method to accurately determine what heat rate improvements, if any, were seen at the time of installation?
   e. Has the plant monitored the heat rate since that time, and monitored the heat rate impact of the technology?
   f. If so, provide a synopsis of data on how the heat rate improvement observed at the time of installation has persisted or degraded.
   g. What is the cost of re-installing the technology?
   h. Is there any meaningful incremental benefit of installing a replacement technology compared to the currently operating technology?
4. Is there additional information to consider in evaluating whether the technology is appropriate for this unit or the expected range of improvement?

These questions should be considered as relevant in the review process. As EPA noted in its guidance, if a BSER HRI technology has already been installed, then BSER may already be met or the additional benefits of the BSER may be so reduced as to not warrant including this technology in calculating the standard of performance for that particular unit The State or permitting authority should document its conclusions for the feasibility and resulting heat rate improvement range, if any, of installing each BSER technology. The cost should be expressed in a consistent fashion, such as \$/ton of CO_2 removed or \$/% HRI.

4.2.1 Neural Networks

Under ACE a neural network is defined as "a computer model that can be used to optimize combustion conditions, steam temperatures, and air pollution at steam generating unit." (84 Fed.

Reg. at 32584). The definition of neural network does not mandate that such a model be online and real-time, rather than a predictive or looking-back model. Nor does the definition mandate that it operate in an open-loop or closed-loop process. Although the preamble states that a neural network "typically…ties into the plant's distributed control system for data input (process monitoring) and process control," this is not mandated. *See* 84 Fed. Reg. at 32538.

The reality is that neural networks and other combustion optimizers and controls are either focused on addressing a specific combustion issue or issues (such as high slagging, elevated CO emissions, etc.) or are focused on a very broad-based performance goal (such as reducing excess air requirements in the boiler). In the heat rate studies conducted recently by Black & Veatch it was found that all plant owners were interested in neural networks only for controlling excess air levels or reducing slagging.

While slagging reduction does have an associated heat rate benefit, the largest benefit seen was from simple excess air reduction in the furnace. Reducing excess air has these benefits:

- Reducing sensible heat losses in the boiler.
- Reducing both forced draft and induced draft fan power requirements.
- Improving the ability of emissions equipment to treat the flue gas (and in one case, where the liquid/gas ratio was able to be reduced, a heat rate benefit due to being able to turn off a scrubber recycle/spray pump).
- Reducing NO_X emissions (and thus potentially reducing auxiliary power required by SCR systems).
- Reducing boiler tube erosion via reduced flue gas flow, thus reducing the frequency of unplanned outages over time. This has a small impact upon the annual average heat rate, as significant fuel energy is required for a coal unit cold start.

Excess air reduction does have the potential drawbacks of increased CO and LOI production, increased lower furnace corrosion, and increased slagging. Thus, the goal of a good neural network system is to maximize the benefits whilst reducing potential drawbacks.

In the studies conducted by Black & Veatch, on average the whole-plant benefit of reducing excess air varied significantly by unit. In some cases, boiler efficiency increased much more than the net plant heat rate improved due to potential heat transfer problems resulting from reduced excess air[11]. In other cases, the net plant heat rate improved at a much greater level than boiler efficiency, due to savings in equipment auxiliary power. Table 4-1 shows the range of boiler efficiency and heat rate improvement which was calculated for a total of 24 units that were analyzed at three different excess air reduction levels (as measured by excess O_2). Note that four units were already

[11] Many of these cases were where a boiler was burning a coal that was significantly different in heat content and ultimate analysis than its design coal.

equipped with advanced combustion controls such that a full neural network deployment was deemed to be not advisable from a cost standpoint).

Table 4-1 Predicted Boiler Efficiency and Net Plant Heat Rate Improvements from Neural Network Deployment

EXCESS O_2 REDUCTION, %	PERFORMANCE METRIC	MINIMUM IMPROVEMENT	MAXIMUM IMPROVEMENT
0.25	Boiler Efficiency	0.02	0.26
	Net Plant Heat Rate	0.01	0.44
0.50	Boiler Efficiency	0.11	0.53
	Net Plant Heat Rate	0.09	0.62
0.75	Boiler Efficiency	0.20	0.77
	Net Plant Heat Rate	0.17	0.75

The typical cost estimated for the 24 assessed units averaged $460,000 for the first first-year, in addition to ongoing software, training, and configuration costs ranging from $20,000 to $60,000 per unit per year thereafter.

Note that in EPA Table 1, the EPA assumed that the typical HRI from application of neural networks or intelligent sootblowers ranged from 0.3% to 1.4%. We feel that the upper boundary of this improvement range is unrealistic, even if neural networks are combined with intelligent sootblowing (see 4.2.2).

4.2.2 Intelligent Sootblowing:

Intelligent sootblowing is defined as "an automated system that use process measurements to monitor the heat transfer performance and strategically allocate steam to specific areas to remove ash buildup at a steam generating unit," 84 Fed. Reg. at 32583, and also described as "automated systems that use process measurements to monitor the heat transfer performance and strategically allocate steam to specific areas to remove ash buildup." *Id.* This BSER HRI technology definition appears narrower than the case for neural networks:

Intelligent sootblowing has a few opportunities for improving heat rate at a unit.

- Reduction of steam or air required for sootblowing, which will result in either a turbine heat rate or auxiliary power benefit for the unit.
- Improved boiler efficiency via improved heat transfer.

- Reduced main steam and reheat steam spray flow due to improved boiler heat transfer.[12]
- Reduced tube erosion from sootblowing, thus leading to reduced unplanned maintenance outages and fewer cold starts.

One of the first situations encountered in the real-world analysis of the benefits of applying intelligent sootblowing is that many units already have some sort of intelligent sootblowing system that is installed. In addition:

- Many high-slagging units have employed water cannons to good effect and would not significantly benefit from further attention.
- Some units that were analyzed by Black & Veatch had no significant slagging problems, and typically operated the furnace wall blowers and long retractable convective pass blowers only once per day, or less.
- Some units which undergo deep cycling or two-shift operation experience significant slag shedding, thus limiting the benefit of improvements.

Among the 28 units studied by Black & Veatch, the range in expected heat rate improvement varied from 0.01% to 0.14%. Black & Veatch is uncertain what factors went into the EPA estimates for intelligent sootblowing heat rate improvement. Typical costs were estimated at $250,000-400,000 per unit, with ongoing software, training, and maintenance costs of about $10,000-20,000 per year.

4.2.3 Boiler Feed Pumps

The definition of boiler feed pumps is fairly well understood, although the ACE rule makes no differentiation as to the expected heat rate benefit or cost between steam turbine-driven pumps versus electric-driven pumps. One of the problems encountered when analyzing the benefit of rebuilding or upgrading the internals of boiler feed pumps is that there has not been significant advancement in boiler feed pump efficiency in the last 20 years. Most plants have taken advantage of potential upgrades, and there is little room for improvement. Moreover, because most coal-fired power plants over 100 MW in size already employ steam-driven boiler feed pumps, adding a VFD to the pump is not likely to give any benefit.

Six of the units analyzed by Black & Veatch did employ electric-driven boiler feed pumps which were found to benefit from VFD deployment. In these cases, the heat rate benefit ranged from 0.39% - 0.42%, at a cost of between $2M – 3.2M per unit. Thus, while some benefit may be gained in some cases, VFD installation typically presented a poor cost/benefit ratio.

[12] Note however some units rely upon a light coating of slag to balance heat transfer in the boiler, sending more heat to the main steam and reheat steam convective tube banks.

4.2.4 Air Heater and Duct Leakage Control

This single BSER HRI technology listing contains within it several components which must be analyzed.

- Improvements to the air heater leakage. This can take the form of replacing seals in-kind, upgraded sealing technology, basket replacement, or an entirely new air heater.
- Improvements to air heater baskets that reduce leakage.
- Repair or upgrade of ductwork and/or expansion joints around the air heater.

There are several benefits of these actions. First, they reduce auxiliary power consumption by the forced draft and induced draft fans, and in some cases, they also reduce auxiliary power consumption by the primary air and scrubber booster fans. Reducing air in leakage also reduces the parasitic load associated with scrubber reheat fans. The improved heat transfer in the air heater results in increased boiler efficiency. Finally, reducing leakage improves the ability of emissions equipment to treat the flue gas[13]. For this BSER HRI technology, the potential improvements will vary widely across the United States coal fleet. Table 4-2 demonstrates the range of heat rate improvement seen across 28 units in recent studies. Please note that all values shown in the table are for Ljungström-type regenerative air heaters – tubular (recuperative-type) and Rothemühle-type air heater data is not reported in this table. Heat rate improvement potential for these types of air heaters, especially tubular air heaters, may be less than indicated for Ljungström-type air heaters.

Table 4-2 Predicted Heat Rate Improvements for Different Approaches in Air Heater and Duct Leakage Reduction.

PERFORMANCE METRIC	MINIMUM IMPROVEMENT	MAXIMUM IMPROVEMENT
Air Heater Retrofit of Movable Sector Plates + Seal Replacement	0.03	0.70
Air Heater Duplex Sealing System with New Baskets (same heat transfer capability) and Movable Sector Plates + Seal Replacement	0.23	2.23

This range of potential improvements is greater than the 0.1-0.4% stated by the EPA in the ACE rule (EPA Table 1). As a result, every coal unit owner that Black & Veatch worked with on these studies

[13] In some cases, a leakage reduction can improve ESP performance by changing the mean temperature of the flue gas through the ESP, thus allowing a more advantageous fly ash resistivity to come into play.

embraced this BSER HRI technology as a factor to be included in calculation potential heat rate improvement. As part of its studies, Black & Veatch also performed a full cost estimation exercise, and the cost ranges that were found are shown in Table 4-3 on the basis of $1,000 per % heat rate improvement on an average annual basis.

Table 4-3 Estimated First-Year Costs for Different Approaches in Air Heater and Duct Leakage Reduction, $1,000 per % Improvement.

PERFORMANCE METRIC	MINIMUM COST	MAXIMUM COST
Air Heater Retrofit of Movable Sector Plates + Seal Replacement	$1,286	$44,000
Air Heater Duplex Sealing System with New Baskets (same heat transfer capability) and Movable Sector Plates + Seal Replacement	$952	$18,043

One concern expressed by plant personnel is that due to the nature of real-world operations and maintenance at coal-fired power plants, any upgrades or repairs to the air heater, ductwork, and air quality control systems casings are at best temporary, as these items are considered to be consumables due to constant fly ash erosion and corrosion from flue gases. This means both that not only will the benefit of any heat rate improvement need to be averaged over the life-cycle of the improvement, but also ongoing operations and maintenance costs must be included. These estimated annual costs for maintaining air heater and duct leakage varied widely from unit to unit, ranging from $20,000 to more than $200,000.

It is also important to note that air heater surface upgrades are not a BSER HRI candidate technology, and thus such modifications would not be considered in determining a unit's standard of performance, however, it could be used to comply with the final standard of performance. EPA elaborates on this topic in Chapter 3 of *EPA's Responses to Public Comments on the EPA's Proposed Emission Guidelines for Greenhouse Gas Emissions From Existing Electric Utility Generating Units*.[14]

4.2.5 Variable Frequency Drives

Although it appears that EPA considered the large plant fans and boiler feed pump as being the targets for VFD deployment, Black & Veatch analyzed the impacts of VFD deployment on many different prime movers in the 28 studies conducted, including:

[14] June 2019, Document ID: EPA-HQ-OAR-2017-0355-26741 available at https://www.regulations.gov/document?D=EPA-HQ-OAR-2017-0355-26741

- Primary air, forced draft, induced draft, and scrubber booster fans.
- Boiler feed pumps.
- Main circulating water pumps.
- Cooling tower fans.
- Scrubber recycle pumps.

Out of 28 heat rate studies, in no case were primary air fan, circulating water pumps, or cooling tower fans found to result in a net benefit with a reasonable payback period for the plant. One of the problems with varying cooling tower fan and circulating water pump power is that this often resulted in reductions of condenser efficiency, thus increasing the backpressure of the condenser and reducing both plant output and plant efficiency. In other cases, other factors prevented use of these options (such as plants which utilize natural draft cooling towers).

In 3 cases, Black & Veatch found that VFD deployment for electric-driven boiler feed pumps resulted in an average heat rate benefit of 0.41%. However, as this was at a cost of between $2M – 3.2M per unit, it represented a poor cost/benefit ratio. In only one instance was deployment of VFDs for scrubber recycle pumps found to be of benefit. It should also be noted, however, that scrubber recycle lines tend to have a minimum flow velocity specification before solid particle drop-out becomes a problem which can potentially clog the main feed lines to the absorber vessel. This therefore places a limit on the turndown capability of these pumps.

In nearly all cases the only real benefit found for VFD deployment was for forced draft and induced draft fans that did not use axial flow control. Out of 28 units a total of 21 large fan systems were found to be worth upgrading: 15 induced draft fan systems, 5 forced draft fan systems, and 1 scrubber booster fan system. Not only was there a potential power savings benefit for using VFDs on these fans (especially at part-load and low-load conditions), there was also a significant potential improvement in control of the units. Table 4-4 shows the results of the forced draft fan studies that were done, and Table 4-5 the induced draft fan studies.

Table 4-4 Forced Draft Fan Studies, Typical Improvement Potential from VFD Deployment

PERFORMANCE METRIC	MINIMUM	MAXIMUM
Auxiliary Power Savings, Minimum Load, MW	0.40	1.70
Auxiliary Power Savings, Maximum Load, MW	0.16	2.10
Cost (2 fans), $	$1,380,000	$2,030,000
Heat Rate Improvement, Annual Average, %	0.09	0.32
Ongoing O&M Cost, $/year	$10,000	$20,000

Table 4-5 Induced Draft Fan Studies, Typical Improvement Potential from VFD Deployment

PERFORMANCE METRIC	MINIMUM	MAXIMUM
Auxiliary Power Savings, Minimum Load, MW	2.80	3.60
Auxiliary Power Savings, Maximum Load, MW	2.30	4.10
Cost (2 fans), $	$2,900,000	$5,650,000
Heat Rate Improvement, Annual Average, %	0.86	1.16
Ongoing O&M Cost, $/year	$10,000	$20,000

As a result, variable frequency drive upgrades to forced draft and induced draft fans, where applicable, can result in similar heat rate improvements as estimated by the EPA (see EPA Table 1).

4.2.6 Blade Path Upgrade (Steam Turbine)

Black & Veatch performed a review of several steam turbine blade path upgrade options for the 28 units it studied. These ranged from non-reheat units under 90 MW, to supercritical pressure units above 800 MW. In each case full heat balance models of the steam turbines were developed, examining the valves wide open (VWO) at 5% overpressure (OP) cases, typical MCR cases, and part-load cases. Two different upgrade options were examined for each steam turbine: the case where only the high pressure (HP) and intermediate pressure (IP) sections were upgrades, and the case where the entire steam path of the turbine was upgraded (HP/IP/LP (Low Pressure) sections). Each analysis was based on the incremental improvement in steam turbine efficiency, with performance improvements and pricing estimates based upon in-house data and past project experience of the Thermal Performance group.

In each case, the steam path upgrades were designed with the goal of maintaining the current maximum gross turbine output, but improving efficiency. This was specifically requested by all plant owners, under the thought that this course of action may help to reduce the probability of triggering New Source Review (NSR).

A potential benefit was found for most units, with the lowest amount of heat rate improvement being 1.25%. Table 4-6 displays the findings of this analysis.

Table 4-6 Steam Turbine Blade Path Upgrades, Typical Improvements and Cost

PERFORMANCE METRIC	MINIMUM	MAXIMUM
HP and IP Section Upgrades		
Heat Rate Improvement, %	1.25	2.45
Cost, $	$11,850,000	$18,700,000
Cost per % Heat Rate Improvement, $	$5,925,000	$13,008,000
Full Steam Path Upgrades		
Heat Rate Improvement, %	1.50	5.15
Cost, $	$19,650,000	$31,600,000
Cost per % Heat Rate Improvement, $	$5,535,200	$13,955,000

These heat rate improvements were independent of any potential change in steaming ability in the boiler, or ability to maintain the typical hot reheat steam outlet temperature and pressure. In a Phase 2 analysis, a coupled boiler and steam turbine model is used to refine the estimates of the net efficiency impact across the entire plant (14 such studies are underway by Black & Veatch at this juncture). Since initial turbine modeling does not reflect manufacturer or OEM guarantees (as no vendor quotes are solicited for a Phase 1 analysis), this level of accuracy is acceptable for this level of analysis.

Three full boiler and steam turbine studies were conducted for one plant owner, and Table 4-7 reflects the difference in the estimated heat rate benefit from the Phase 1 versus the Phase 2 study. In each case, including the boiler modeling allowed a better assessment of the net potential heat rate improvement, as well as providing insight on which specific areas of the boiler were not able to support the higher level of steam generation (in this case, approximately 10% greater reheat surface area was required).

Table 4-7 Steam Turbine Blade Path Upgrades: Phase 1 vs. Phase 2 Study Findings

STUDY	HEAT RATE IMPROVEMENT, %
HP and IP Section Upgrades	
Phase 1 Heat Rate Improvement, %	1.9
Phase 2 Heat Rate Improvement, %	1.5
LP Section Upgrades	
Phase 1 Heat Rate Improvement, %	1.3
Phase 2 Heat Rate Improvement, %	1.2
Full Steam Path Upgrades (HP/IP/LP)	
Phase 1 Heat Rate Improvement, %	2.8
Phase 2 Heat Rate Improvement, %	2.4

4.2.7 Redesign/Replace Economizer

This BSER HRI technology option appears at first to be highly desirable, as improving the heat transfer ability of the economizer can improve the boiler efficiency and reduce the flue gas volumetric flow rate by cooling the gas. Moreover, the economizer does not typically require regular maintenance to sustain the heat rate improvement, outside of typical boiler tube life-related activities. However, what was discovered in the course of nearly all of the 28 heat rate studies was that reducing the economizer gas outlet temperature can have negative impact upon SCR performance. As the SCR lies downstream of the economizer, and often has a minimum inlet temperature required before operation is possible, reductions in the flue gas temperature entering the SCR can reduce the flexibility of the unit by increasing the minimum safe load at which the SCR can be operated. This can be a serious drawback to operations, especially as coal-fired power plants are increasingly required to operate SCRs.

Low flue gas temperatures can impact other downstream equipment, such as air heaters and particulate removal equipment (ESPs and fabric filter baghouses). Sulfur corrosion and ammonium bisulfate deposition can increase significantly in air heaters as the cold-end average temperature decreases. The corrosion potential of flue gas ductwork, ESPs, and fabric filter baghouses are also significantly impacted by flue gas temperatures. In some uncommon cases, low flue gas temperatures can result in changes in fly ash resistivity that can reduce ESP effectiveness.

As some units already suffer from low economizer flue gas outlet temperatures, they have been forced to deploy creative techniques to increase the temperature at part-load conditions. Such techniques include:

4.2.7.1 Economizer Gas Bypass

These systems employ actuated dampers upstream of the economizer banks to allow a portion of the hot flue gas to bypass the economizer, subsequently being mixed in with the remainder of the flue gas downstream of the economizer. While once originally employed to increase flue gas temperatures to primary air heaters to assist in mill coal drying, or to aid in startup, they now are employed to modulate SCR inlet temperatures. The negative impacts of these systems include high installation cost, high maintenance for the dampers and controls, and a reduction in boiler efficiency.

4.2.7.2 Economizer Water Bypass

Economizer water bypass is employed much less frequently than economizer gas bypass, and typically consists of a system whereby some of the feedwater at the economizer inlet header is bypassed entirely around the economizer banks, into the outlet header or some other connection downstream. Some plants employ secondary economizers downstream of the main economizer, which can have either water or gas flow modulated to them such that they can be used to vary flue gas temperatures. These systems tend to have a higher capital and O&M cost than gas bypass systems, but can be very useful for assisting in boiler startup. They also reduce the boiler efficiency as a result of less flue gas heat transfer to the water circuit.

4.2.7.3 In-Duct Burners

The method of last resort for increasing flue gas temperatures leaving the economizer is by deploying natural gas burners in the flue gas ductwork downstream of the economizer. This system has the advantage of a straightforward and lower-cost installation, but a very high operating cost due to the cost of gas. As only part of the sensible heat added to the flue gas by the natural gas burners can be recovered effectively by the air heaters, these systems can also have the net effect of significantly worsening the heat rate of the unit. In three studies conducted by Black & Veatch on such systems, it was found that the heat rate penalty of using in-duct natural gas burners was 1-2%. Thus, in at least one of the cases studied a net heat rate benefit was realized by reducing the economizer tube surface area – while the boiler efficiency was reduced, the improvement in heat rate from removing the natural gas burners far outweighed the boiler efficiency effects.

Table 4-8 lists the typical findings for economizer surface area modifications that were conducted by Black & Veatch across the 28 heat rate studies. It will be noted that in several cases there was a worsening of heat rate; indeed, even the average heat rate effect was a worsening of 0.04%. Any worsening of the net plant heat rate was due to cases where the turbine cycle efficiency was impacted by the imbalance of heat transfer more than the boiler efficiency was improved. Typically, the problem seen in these cases is proper balance of heat to the reheat circuit, so in these cases modifications to the reheater tube banks may be required in order to fully utilize a heat rate improvement from economizer modifications.

Table 4-8 Economizer Upgrades (Adding Heat Transfer Surface), Typical Improvements and Cost

PERFORMANCE METRIC	MINIMUM	MAXIMUM
Minor Upgrades (1-2 additional tube passes of area)		
Heat Rate Improvement, %	-0.82	0.51
Cost, $	$800,000	$2,350,000
Cost per % Heat Rate Improvement, $	$4,608,000	N/A
Major Upgrades (3+ additional passes of area)		
Heat Rate Improvement, %	-0.14	0.91
Cost, $	$1,000,000	$3,900,000
Cost per % Heat Rate Improvement, $	$4,235,000	N/A

4.2.8 Improved Operating and Maintenance Practices: Heat Rate Training

A heat rate awareness training course typically covers the fundamentals of determining unit performance, how to use these metrics, and the operating conditions and decisions that impact unit efficiency and heat rate. A course should include numerous real-life case studies identified through years of monitoring and diagnostic work, and be more substantive than a single-day seminar. Courses can be tailored to focus upon specific equipment systems of the plant, as well as discussing the general best practices of heat rate awareness, controllable loss monitoring, and operations and maintenance activities. In the studies conducted by Black & Veatch, the estimated cost to conduct an annual heat rate awareness course is estimated as being $15,000 to $30,000 to cover a large plant staff with multiple units. Another significant heat rate operating practice is the utilization of plant performance monitoring practices, which may include software packages, that monitor the performance of critical plant processes impacting unit efficiency/heat rate.

The actual heat rate benefit from training is extremely difficult to quantify. However, as Black & Veatch has conducted scores of heat rate awareness courses over more than 30 years we have found that in many cases plant staff report that increased awareness of the true cost of controllable losses, as well as improved methods to utilize online monitoring and diagnostics to find and quantify controllable losses, to be effective practices. A summary of reported experience indicates that the typical heat rate improvement after comprehensive training may range from 0.1% to 0.5% in the first year subsequent to training.

4.2.9 Improved Operating and Maintenance Practices: On-Site Appraisals

This specific item is not clearly defined within the ACE rule and appears to be open to potentially broad interpretation. Indeed, the EPA was not able to provide suitable guidance for estimated ranges of capital cost, ongoing operations and maintenance costs, or heat rate improvement for specific tasks or sub-projects under this category.

On-site heat rate appraisals are often conducted via detailed assessment of controllable losses, especially those which can be reduced or eliminated by low-impact operations changes and equipment repairs and upgrades. This assessment utilizes a combination of a review and analysis of historical operations data, interviews with plant operations and maintenance personnel, review of past test and capability reports, a detailed study of the current fuel sources and fuel-related impacts upon the plant, discussions with plant management to understand the plant generation goals and objectives, and a reliability and maintenance history analysis.

Real-world examples of heat rate improvement projects resulting from on-site heat rate appraisals and audits include the following:

- Diagnosis of a cracked feedwater heater partition plate via analysis of online performance data, which resulted in a $12,000 monthly heat rate savings and 0.4 MW capacity improvement.
- Discovery of a failed reheat stop valve by analyzing reheat pressure swings over time, resulting in a $65,000 monthly heat rate improvement and 4 MW capacity improvement.
- An audit of TTD and DCA temperature trends across a feedwater heater train at one power plant found that the highest-pressure feedwater heater emergency drain valve was leaking, with 50% of its flow returning to the condenser, rather than cascading to the next feedwater heater. This failure resulted in a heat rate loss of 53 Btu/kWh (about 0.5%) and a net capacity loss of 2.5 MW.

- Testing of mill dirty-air flows and coal flow balances at one power plant found that by rebalancing the flows on 4 mills to bring the coal and air flow deviation to within +/- 10% (compared to the +/- 30% it formerly operated at), coal unburned carbon heat losses decreased by 0.5%, which directly translated to a heat rate improvement of 0.5%. Moreover, burner-zone slagging was nearly eliminated by this change, resulting in significantly less use of sootblowing steam in the furnace wall blowers, which resulted in an additional long-term heat rate benefit of 0.1% (and a corresponding improvement in furnace wall tube life).
- Long-term analysis of subtle deviations in feedwater heater extraction lines revealed an internal line had failed, resulting in not only a $15,000 heat rate loss, but the potential for an unplanned outage due to debris in the heater.
- An analysis of 19 different test coals supplied to a power plant found that not only were 7 of the coals unprofitable to burn, burning the worst coal resulted in a heat rate loss of more than 2%. Moreover, this coal was responsible in whole or in part for the majority of the plant de-rates due to high-temperature sodium-based fouling, which cost the unit an additional 1.2% in heat rate on an annual basis due to the increased number of starts and stops from fouling-related outages.
- A long-term analysis of plant CEMS data and motor amperage data found that a malfunctioning VFD controller in the coal handling system was responsible for incorrect blending of two different coals to meet the plant SO_2 limit, resulting in not only excess use of low-sulfur coal, but a loss of heat rate equating 0.6% on an annual basis.

Heat rate assessment is an ever-moving target, so while there is substantial benefit from a focused heat rate auditing and improvement program, long-term use of some type of performance and O&M monitoring system will provide the best overall heat rate improvement.

4.2.10 Improved Operating and Maintenance Practices: Improved Steam Surface Condenser Cleaning

Condenser cleanliness is critical for the direct impact that it has upon the condenser backpressure, which in turn has a direct impact upon both the net plant heat rate and the potential maximum generation of the unit. Condenser cleanliness can be managed by various means, including increased scheduled outages for more detailed cleaning, injection of biocide or anti-scaling additives, increased and improved water filtration for open-loop cooling systems, and online systems. The most common online cleaning systems are circulating ball systems, where abrasive-coated polymer balls are circulated through the internals of the condenser tubes to provide cleaning in a continuous fashion. The downside of these systems is the potential for balls to escape the system and either be ejected to the environment, or to interfere with other equipment. The ACE rule only states that cleaning can be conducted by offline or online methods, and does not specify any specific method, leading some plant owners to speculate that improved biocide/anti-scaling treatments may qualify.

Table 4-9 lists the typical findings for online condenser cleaning systems that were conducted by Black & Veatch across the 28 heat rate studies. In 7 studies online cleaning systems were already in place and were not included. It will be noted that in some cases access to the condenser was severely limited, which increased the cost substantially.

Table 4-9 Condenser Cleaning Upgrades, Typical Improvements and Cost

PERFORMANCE METRIC	MINIMUM	MAXIMUM
Heat Rate Improvement, %	0.15	0.60
Cost, $	$400,000	$800,000
Cost per % Heat Rate Improvement, $	$833,000	$2,660,000

4.3 BSER HRI Technologies and Their Differing Impact Depending Upon Full-Load or Annual Operation

Table 4-10 provides qualitative descriptions of the relative benefit of each BSER HRI technologies when measured at full-load operation and over the annual load-demand curve.

Table 4-10 Relative Benefit for each BSER HRI Technology

BSER HRI TECHNOLOGY	FULL LOAD	ANNUAL
Neural Network/Intelligent Sootblowing	Equivalent relative benefit at full load and over the annual load-demand curve.	
Boiler Feed Pumps	Lesser benefit.	Slightly greater benefit at lower loads and better control during cycling.
Air Heater / Duct Leakage Control	Slightly better benefit at full load, especially for emissions equipment and derate avoidance.	Lesser benefit.
Variable Frequency Drives	Minimal benefit.	Greater benefit at lower loads and better control during cycling.
Steam Turbine Blade Path Upgrades	Depends upon the desired upgrade.	Depends upon the desired upgrade.
Economizer Upgrades	Greater benefit.	Lesser benefit. Does not significantly improve cycling heat rate.

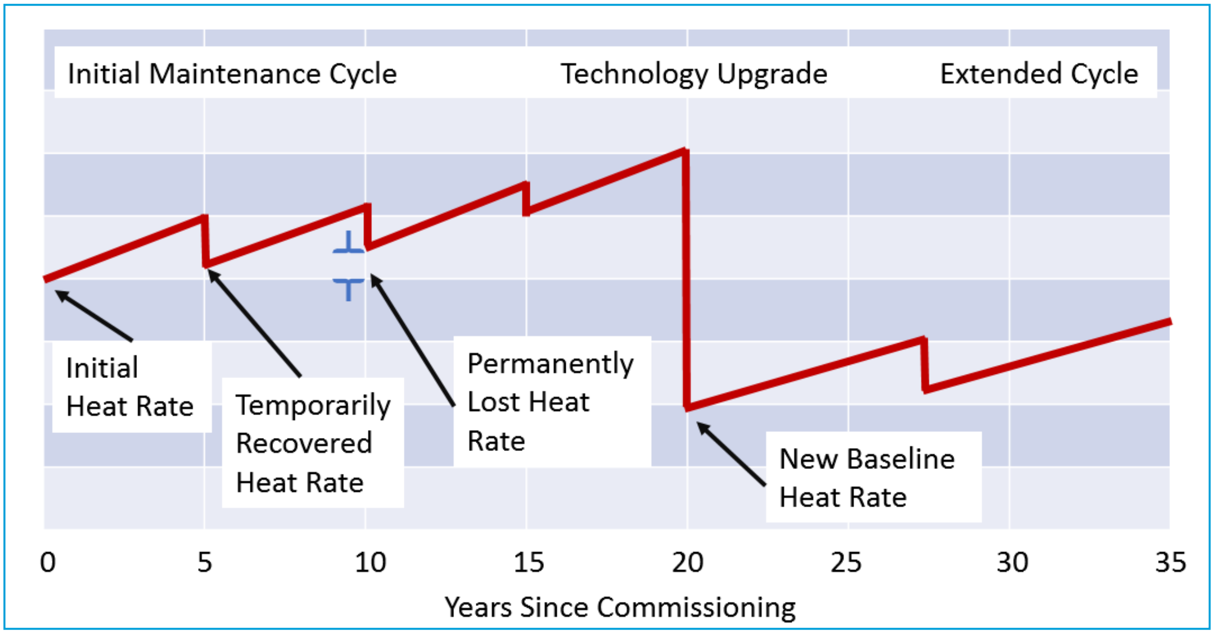
O&M: Training	Mostly equivalent.	Could yield improved benefits at part-load depending upon the training regimen.
O&M: On-Site Appraisals	Equivalent relative benefit at full load and over the annual load-demand curve.	
O&M: Condenser Cleaning Upgrades	Equivalent relative benefit at full load and over the annual load-demand curve.	

4.4 Heat Rate Degradation Cycles for the Various BSER HRI Technologies

Each of the BSER HRI technologies has an inherent benefit life-cycle which must be included in the planning for long-term effectiveness of each option. Most plant engineers are familiar with these cycles, although it helps to visualize them on a relative scale. For example, the expected degradation curve of a steam turbine is shown in Figure 4-1, where at Year 20 a technology upgrade is made that not only improves the heat rate significantly, but also allows for extended time between scheduled maintenance outages. Stepping through this graphic:

1. Year 0 represents the starting point. As the turbine operates over the years, the heat rate gradually worsens due to seal wear, blade and nozzle erosion, deposits on the turbine parts, etc.
2. At Year 5 a routine maintenance outage occurs, which allows recovery of some heat rate loss, but not all.
3. At Year 10 a second routine maintenance outage occurs, which allows recovery of some heat rate loss, but again not all. There is the start of a steadily increasing trend in irrecoverable heat rate loss.
4. At Year 15 a third routine maintenance outage occurs, which again allows recovery of some heat rate loss, with the result being slightly worse than witnessed at Year 10.
5. At Year 20 a major technology improvement is implemented on the turbine, such as HP/IP/LP upgrades, improved seals, etc. This results in the establishment of a new, much lower (improved) heat rate for the unit. The new technology also allows for a shift to a 7-year routine maintenance cycle.
6. At Year 27 a routine maintenance outage occurs, which allows recovery of some heat rate loss, but not all. Here the cycle of gradual steady irrecoverable degradation begins anew.

Figure 4-1 Hypothetical Steam Turbine Heat Rate Degradation and Recovery Curve



Some BSER HRI technologies will have similar degradation curves, but on different schedules and with different magnitudes of heat rate recovery during maintenance cycles. These performance curves will vary greatly with each deployment, based upon the specific technology chosen and the operating conditions of the power plant itself. At this point in time, only broad estimates may be made of the impacts of wear and tear on these technologies. Table 4-11 lists the expected time to loss of 50% of the heat rate improvement for each BSER HRI technology that is considered by ACE.

Table 4-11 Estimated Duration to Loss of 50% Benefit for BSER Heat Rate Improvements

BSER HRI TECHNOLOGY	TIME TO LOSS OF 50% IMPROVEMENT
O&M: On-Site Appraisals	6 to 12 Months
Air Heater / Duct Leakage Control	9 to 24 Months
O&M: Training	1 to 2 Years
O&M: Condenser Cleaning Upgrades	2 to 5 Years
Steam Turbine Blade Path Upgrades	4 to 6 Years
Boiler Feed Pumps	4 to 7 Years
Economizer Upgrades	> 10 Years
Neural Network/Intelligent Sootblowing	> 10 Years
Variable Frequency Drives	> 10 Years

Obviously, some of these estimates are very highly subjective – for example, placing a value on how well training for heat rate improvements is retained and beneficial is nearly impossible. Other factors that come into play that will impact the longevity of a heat rate improvement during any specific time range will be such things as:

- The operating hours of the plant.
- Its load cycling profile.
- The number of starts and stops, and whether they are cold/warm/hot.
- Fuel quality changes that are outside of the ordinary operation.
- The addition of equipment that could have downstream impacts – such as adding a sorbent injection system upstream of an air heater.

4.5 Capital and Maintenance Costs Over the Life of the BSER Upgrade

Certain BSER HRI technologies will require continuous maintenance and upkeep activities in order to maintain their heat rate improvement potential. Nonetheless, even with the best maintenance practices some heat rate improvement options will decline in efficiency over time. This is discussed in Section 4.4, specifically Table 4-11. Table 4-12 details the frequency at which capital and O&M expenditures are required for each of the BSER HRI technologies.

Table 4-12 HRI O&M and Capital Requirements for Sustained Performance

BSER HRI	O&M FREQUENCY	CAPITAL IMPROVEMENT FREQUENCY
Neural Network/Intelligent Sootblowers	Increased O&M from normal. Could be continuous if third-party monitoring and diagnostics are used.	Primarily at project start.
Boiler Feed Pumps	Equivalent to existing for BFPs.	Significant at project start.
Air Heater & Duct Leakage Control	Potentially increased O&M needed to maintain systems.	Primarily at project start.
Variable Frequency Drives	Regular O&M needed to maintain systems.	Primarily at project start.
Blade Path Upgrade (Steam Turbine)	Regular O&M needed to maintain systems.	Significant at project start.
Redesign/Replace Economizer	Regular O&M needed to maintain systems.	Significant at project start.
Improved O&M Practices:		
Adopting HRI Training for Plant O&M Staff	Increased O&M from normal.	N/A

Adopting On-Site Appraisals for Identifying Additional HRI Areas	Increased O&M from normal.	N/A unless specific needs are uncovered.
Improved Condenser Cleaning Strategies	Increased O&M from normal.	Potentially at project start.

4.6 Timing of Heat Rate Improvement Projects

Due to the economic penalty and risk associated with any plant outage, the best option for deployment of a heat rate improvement project at a unit is by incorporating the projects into the regular planned unit maintenance outages. This creates two problems: First, major outage scheduling may not align with the desired deployment time for a specific heat rate improvement option.

For example, the typical outage time between turbine overhauls can be as short as 6 years, with some units able to achieve a 10-year overhaul schedule. Major boiler outage scheduling was once every 2 years, but has been increased over time to being typically once every 3-5 years. If these outage schedules are to be maintained, a unit's ACE compliance schedule would need to reflect these timing constraints to avoid taking premature and expensive additional outage time to install these technologies. For example, performing a steam path heat rate improvement upgrade during the regularly scheduled turbine overhaul.

Second, some heat rate improvement options will require longer outage periods than the normally scheduled outages to complete their deployment. At one time the standard duration for a boiler outage was 30 days, and the standard duration for a turbine outage was 60 days. Although progress has been made by plant owners/operators in reducing these outage times, they are still considered to be reasonable times that consider contingency for unexpected problems during the outage.

In the case of some heat rate improvement options, preparation, planning, and some implementation can be performed earlier than the main deployment. One example is implementing installation of neural networks and/or intelligent sootblowing, whereby some early work could be done regarding installation of new instrumentation and development of site-specific software.

Table 4-13 shows the estimated outage times required for different heat rate improvement options, based upon Black & Veatch experience.

Table 4-13 Typical HRI Project Logistics – Required Outage Duration for Deployment

BSER HRI	< 10 DAY OUTAGE	10 TO 30-DAY OUTAGE	> 30 DAY OUTAGE
Neural Network/Intelligent Sootblowers	Yes	Rarely	No
Boiler Feed Pumps	Possible	Yes	Rarely
Air Heater & Duct Leakage Control	Possible	Yes	Rarely
Variable Frequency Drives	Yes	Possible	Rarely
Blade Path Upgrade (Steam Turbine)	No	Possible	Yes
Redesign/Replace Economizer	No	Rarely	Yes[15]
Improved O&M Practices: Adopting HRI Training for Plant O&M Staff	N/A	N/A	N/A
Improved O&M Practices: Adopting On-Site Appraisals for Identifying Additional HRI Areas	N/A	N/A	N/A
Improved O&M Practices: Improved Condenser Cleaning Strategies	Yes	Rarely	No

[15] Economizer replacement or major modifications could require from 60-90 days of outage time.

5.0 EPA “STEP TWO” – OTHER FACTORS REVIEW

5.1 Accounting for Remaining Useful Life of the Facility

As discussed in Section 1.2, states have the ability to consider a unit’s remaining useful life in determining if a BSER HRI technology is applicable to a unit.[16] If the owner of an affected unit has established a retirement date for the unit, states should factor this into their analysis if the remaining life is expected to be shorter than the life of the BSER HRI technology project. Failure to consider the remaining useful life in these instances could subject the businesses and residents within the state to unnecessarily higher electric rates.

It is the opinion of most Black & Veatch boiler engineers, as well as many others surveyed informally in the electric power industry, other than a catastrophic failure of a major plant component (boiler housing, drum, ring header, steam turbine, scrubber, etc.) or major boiler re-tubing being required, most coal power plants that are still in operation at 2020 should be able to operate until at least 2040, with newer plants being able to operate past 2050. Market competitiveness of the plant will be a major factor. Non-competitiveness in markets due to low costs for natural gas-, wind- and solar-based systems are often identified as big drivers for retirements. Other announcements emphasize the push by customers for cleaner energy, and in some cases, the age of the units is driving up maintenance costs. The bottom line is that each shut down is often a unique decision by the owners based on a multitude of factors, and as such, states regulatory authorities should take direction from the unit owners as to the remaining useful life of affected coal-fired units.

5.2 Scheduling Factors at Multi-Unit Sites

States and owners/operators need to give careful consideration to the scheduling of BSER HRI technology upgrades. Scheduling of capital projects at multiple units at a single site can be problematic depending upon the magnitude and scope of the projects. First of all, multi-unit sites typically stagger major outages (see Section 4.6) such that both units are not off-line concurrently to minimize the costs associated with replacement capacity and energy. While it may be possible to implement some of the BSER HRI technologies during a shorter outage, the construction schedules for any HRI implementation needs to be carefully considered, including and additional costs for replacement capacity and energy.

If multiple capital projects are being considered, there are some important factors to consider when pursuing ACE-related upgrades.

[16] Remaining useful life is a factor States are allowed to consider in establishing a standard of performance under CAA § 111(d)(1), 42 USCA §7411(d)(1); and 40 CFR §§ 60.5755a(a)(2)(i) and 60.24a(e). Remaining useful life is affected by physical, economic, and regulatory factors that affect each unit in different ways.

5.2.1 Neural Network/Intelligent Sootblowing

Depending upon the segregation of the plant control systems, data acquisition system, monitoring and diagnostics, and data historians, implementing neural networks and intelligent sootblowing at one unit at a plant site may interfere with the operations of other sites. In addition, once such a system is deployed it may be required that all operators undergo training on the systems, even if the system is only deployed upon a single unit, such that operators will be able to share duties and substitute for each other in emergencies.

5.2.2 Boiler Feed Pumps, Air Heater and Duct Leakage Control, and Variable Frequency Drive Deployment

While specific challenges may exist at any site, it is unlikely at most sites that upgrading one unit's boiler feed pumps, repairing duct leakage or air heaters, or deploying variable frequency drives on main plant motors will impact the operation of other units.

5.2.3 Steam Turbine Blade Path Upgrades

Steam turbine upgrades often require significant laydown area on the plant turbine deck or a specific maintenance housing, and as a result upgrading two or more steam turbines at once can entail logistical challenges.

5.2.4 Economizer Surface Upgrades

For the case of boilers inside a housing that are located with minimal clearance, replacing or upgrading the economizers at more than one unit can entail logistical challenges from manipulating the tube bundles into position.

5.2.5 Operations and Maintenance: Training

Heat rate awareness and assessment training typically works best when staff from multiple units on-site can attend at once. However, the demands of operating the units and conducting maintenance activities typically precludes this, thus often requiring rotating staff through in shifts, or holding training classes multiple times per year.

5.2.6 Operations and Maintenance: On-Site Appraisals

Multi-unit sites do not typically present challenges to heat rate assessment and improvement staff. In fact, economies of scale or common purpose are sometimes realized.

5.2.7 Operations and Maintenance: Condenser Cleanliness

While specific challenges may exist at any site, it is unlikely at most sites that upgrading or deploying a condenser cleaning system at one unit will impact the operation of other units.

5.3 Unreasonable Cost of Controls

The term "unreasonable cost of controls" derives from 40 CFR § 60.24 – "Emission standards and compliance schedules," part (f), wherein the full term is actually "Unreasonable cost of control resulting from plant age, location, or basic process design." EPA does not, however, explicitly define what constitutes an unreasonable cost of controls. In engineering projects conducted by Black & Veatch and others, the cost-justification of an emission control technology is built up in a pro forma sheet, wherein a large number of factors must be considered, with the ultimate goal being to determine whether implementation of the project would result in the power plant becoming non-competitive in the marketplace.

While it is beyond the scope of this paper to provide a fully-detailed example of a pro forma analysis for a plant upgrade, in general such an analysis must consider the following items:

- The all-in cost of the upgrade, as well as any financing costs that are associated with it, as well as the remaining life of the facility.
- Any cost reductions resulting from the project. See Section 5.5.
- The cost of the lost generation and lost opportunity cost related to any plant outage related to the upgrade, as well as replacement power costs to cover generation commitments.
- Ancillary cost impacts upon other equipment at the plant – for example, installation of a larger economizer may reduce the flue gas temperature entering the SCR system such that a different catalyst must be installed to meet NO_X regulations at the new lower operating temperature.
- Escalation rates of commodities and power prices over the remaining life of the facility, as well as disposal costs of waste products.
- A prediction of the competitiveness of the power plant over its remaining life in terms of the scheduling (to the extent it is known) of other coal plant retirements, gas plant construction, renewable energy deployment, or demand-side management measures. In some analyses conducted by Black & Veatch, a Monte Carlo analysis is conducted upon critical economic factors to determine the probability of competitiveness with many different economic scenarios.

5.4 Physical Impossibility

In the ACE rule, the term "physical impossibility" with respect to setting a standard of performance for a unit is not explicitly defined, nor are any examples provided. The term is found in 40 CFR § 60.24a – "Standards of performance and compliance schedules," wherein it is stated:

> (e) In applying a standard of performance to a specific source, the State may take into consideration factors, such as the remaining useful life of such source, provided that the State demonstrates with respect to each such facility (or class of such facilities):
>
> (1) Unreasonable cost of control resulting from plant age, location, or basic process design;
>
> (2) Physical impossibility of installing necessary control equipment; or

> (3) Other factors specific to the facility (or class of facilities) that make application of a less stringent standard or final compliance time significantly more reasonable.

40 CFR 60.24a(e).* Physical impossibility might be demonstrated for safety issues, such as where the plant would become unsafe to employees or surrounding communities; where additional land is required and, because it is owned by a party not subject to condemnation, cannot be obtained; or possibly where the proposed technology were to violate local law. In most other cases, impossibility is more a question of cost and may be best considered in that factor.

In the Regional Haze proceedings, EPA recognized that notwithstanding a control being "cost effective" on a $/ton basis, "there may be cases the installation of controls would affect the viability of continued plant operations." 87 Fed. Reg. 25184, 25228 (May 5, 2004). In such cases, EPA advised a state or permitting authority as follows:

> "Nonetheless, we recognize there may be unusual circumstances that justify taking into consideration the conditions of the plant and the economic effects of requiring the use of a given control technology. These effects would include effects on product prices, the market share, and profitability of the source. We do not intend, for example, that the most stringent alternative must always be selected, if that level would cause a plant to shut down, while a slightly lesser degree of control would not have this effect. Where there are such unusual circumstances that are judged to have a severe effect on plant operations, you may take into consideration the conditions of the plant and the economic effects of requiring the use of a control technology. Where these effects are judged to have a severe impact on plant operations you may consider them in the selection process, so long as you provide an economic analysis that demonstrates, in sufficient detail for a meaningful public review, the specific economic effects, parameters, and reasoning. (We recognize that this review process must preserve the confidentiality of sensitive business information.) Any analysis should consider whether other competing plants in the same industry may also be required to install BART controls."

Id. It is likely a similar approach could be used in assessing physical impossibility claims.

5.5 Co-Benefits of Reduced O&M, Fuel, and Other Costs

In most cases it is a safe simplifying assumption that a percent reduction in the net plant heat rate will result in an equivalent percent reduction in the coal burn rate. This will result in the quantifiable impacts which can be measured and counted as a savings to the plant on a per-MWh basis. Assuming that the total annual net generation of the unit is unchanged, the following benefits can be expected.

5.5.1 Reduced Consumables

Reduced coal and transportation costs are obvious benefits, but there will also be a reduction in the emissions associated with coal handling activities, including coal dust and fines. Coal additives will

* This citation was revised. The initial version of the report cited 40 CFR 60.24(f) from the exisiting Subpart B language that remains in effect for some source categories, versus the correct 40 CFR 60.24(e) from the new Subpart Ba language that applies to existing EGUs subject to Subpart UUUUa.

be reduced, as will additives for emissions controls equipment, such as ammonia or urea, lime or limestone, activated carbon.

5.5.2 Reduced Waste Products

Commensurate with the reduction in coal burn rate, waste products from the plant will be reduced. Ash production is often touted as a major benefit, although if fly or bottom ash is currently sold, the net benefit may be less than for a plant which must landfill all of its ash. Similar to this is waste from the scrubber, where gypsum production may be reduced. If a lime or sodium-based fixative is required for the scrubber waste, this will be reduced as well.

5.5.3 Reduced Maintenance

Reducing the coal burn rate will reduce abrasion and erosion for any equipment that is part of the coal handling or fuel preparation and firing systems. The boiler will benefit from reduced coal flow and subsequently reduced tube erosion and corrosion. For heat rate improvements that reduce the excess air level in the furnace, such as neural network controls, the erosion from fly ash may be reduced significantly further. Likewise, an intelligent sootblowing system may be expected to reduce tube erosion from over-sootblowing, thermal shock from over-sootblowing, and damage due to catastrophic slag falls to the lower slope of the furnace ash hopper. Unless these issues have been a recurring difficulty with plant operation, they may not require quantification.

Heat rate improvements that also reduce the flue gas flow rate (neural networks, air heater and associated duct leakage control) will result in less fly ash erosion to the SCR system, air heater, ESP, fabric filter baghouse, dry scrubbers, ductwork, and other emissions equipment.

5.5.4 Reduced Emissions

Reducing the coal burn rate is likely to reduce most coal-related emissions by a proportional basis, which will lead to reduced SO_2, NO_X, particulates and heavy metals. Should the heat rate improvement method also incorporate reducing excess oxygen in the furnace, or utilizing a neural network for combustion optimization, NO_X and CO emissions may also be reduced. Heat rate improvement options that reduce the flus gas flow rate (such as air heater and associated duct leakage control, economizer upgrades, or neural networks) may reduce the volumetric flow rate of flue gas such that the efficiency of emissions equipment is improved. This can sometimes allow wet scrubbers to operate with one less recycle pump, thus reducing auxiliary power and improving heat rate.

5.5.5 Reduced Auxiliary Power Requirement

Reduced flue gas flow rates may reduce the power demands of the induced and forced draft fans if the fans are equipped with VFDs.

5.5.6 Reduced Labor

Modest heat rate improvements such as are targeted with ACE BSER HRI technologies are unlikely to reduce station staffing.

5.5.7 Increased Fuel Flexibility for Reduced Operation Costs

The heat rate reduction and operations improvements resulting from implementation of ACE BSER HRI technologies may allow for greater fuel flexibility at the unit. Aside from the benefits of reduced coal burn rate allowing potentially lower-BTU coals to be burned, other operations benefits include:

- Neural networks and intelligent sootblowing systems may allow higher-slagging or higher-fouling coals to be burned.
- The NO_X reduction potential from neural networks may allow higher nitrogen or lower-volatile matter coals to be burned.
- As a common problem with burning Powder River Basin coals is elevated economizer flue gas exit temperatures, increasing the economizer tube surface area may mitigate this effect.
- Any BSER HRI technology that reduces flue gas volumetric flow rates will increase the operating margins of the induced draft fans and emissions equipment, potentially allowing lower-BTU coals to be burned.

As the coal cost is typically from 50% to 80% of the total busbar cost of generation at a coal-fired power plant, the potential to burn a coal that is even 4% cheaper than the current coals could result in a 2% cost savings.

5.6 Considering New Source Review in Assessing BSER HRI Technologies Cost and Timing

The federal New Source Review programs encompass Prevention of Significant Deterioration (PSD) review for new or modified major sources in attainment or unclassifiable areas or nonattainment new source review (NNSR) for major sources of nonattainment pollutants (including precursors) in nonattainment areas. Certain of the proposed BSER HRI technologies may, in some instances, potentially trigger either PSD or NNSR depending upon the relevant permitting authority's program status, regulations and guidance. If a candidate technology would or potentially could trigger PSD or NNSR review, the timing and cost of the PSD or NNSR review are relevant factors that should be considered in determining whether the candidate technology is feasible or cost effective.

For example, if a source were to trigger major modification under PSD for NO_x due to the need for reheaters and, under relevant permitting authority guidelines, best available control technology for the source were selective catalytic reduction (SCR), then the cost of the SCR installation and operation should be considered as part of the BSER HRI technology review. Further, if the SCR installation would require additional time, that time would need to be included in the ultimate compliance timing and deadlines included in the state plan.

Similarly, if a source were to trigger major modification under NNSR for NO_x in an ozone nonattainment area, the BSER HRI technology review would need to assess the availability and cost of both whatever technology would be considered lowest achievable emission rate plus the availability and cost of offsets. If sufficient offsets were not available at reasonable cost, then the candidate technology may not be appropriate.

Owners/operators and state regulatory authorities will need to carefully consider the possible emissions increases that could result from implementation of the BSER HRI technologies and, if PSD or NNSR or equivalent local program requirements are triggered for one or more pollutants, include them in the feasibility, cost and timing analysis.

6.0 SETTING A FINAL STANDARD OF PERFORMANCE

In setting a final standard of performance, the preamble to the proposed rule described two steps states would go through (either separately or simultaneously): (1) assess the BSER HRI technologies' applicability to a designated facility's emission performance and calculate the resulting emission rate and (2) adjust that rate by considering the remaining useful life of the designated facility and other source-specific factors. As seen in this guidance, these "two steps" likely will require a five-task sequence of analysis by owners/operators and state regulatory authorities. The first three tasks relate to EPA's "Step One" and the final two tasks equate to EPA's "Step Two." Proceeding in this fashion ensures that all of the considerations set forth in the preamble and regulations and the engineering and operational issues discussed in Sections 3 through 5 are addressed and properly considered in setting a standard of performance. EPA explains that, in setting a standard of performance, a state can account for emissions variability in many ways including setting range-based limits and establishing specific conditions at which compliance is established. Following is part of EPA's explanation.

> Second, standards of performance should reflect variability in emission performance at an individual designated facility due to changes in operating conditions. Specifically, the agency believes it would be appropriate for states to identify key factors that influence unit-level emission performance (*e.g.,* load, maintenance schedules, and weather) and to establish emission standards that vary in accordance with those factors. In other words**, states could establish standards of performance for an individual EGU that vary (*i.e.,* differ) as factors underlying emission performance vary. For example, states could identify load segments (ranges of EGU load operation) that reflect consistent emission performance within the segment and varying emission performance between segments. States could then establish standards of performance for an EGU that differ by load segment.**
>
> Another possible option to account for variable emissions is **to set standards of performance based on a standard set of conditions.** A state could establish a baseline of performance of a unit at specific load and operational conditions and then set a standard against those conditions via the application of the BSER. Compliance for the unit could be demonstrated annually (or by another increment of time if appropriate based on the level of stringency of the standard of performance set for the unit) at those same conditions. In the interim, between the demonstration of compliance under standardized conditions, a state could allow for the maintenance and demonstration of fully operational candidate technologies to be a method to demonstrate compliance as the standard of performance must apply at all times.
>
> The Agency believes that these approaches to providing flexibility (and possible others not described here) in establishing standards of performance are reasonable and appropriate by accounting for innate variable emission performance across EGUs and at specific EGUs while

> also limiting this flexibility to instances in which underlying variable factors are valuated and linked to variable emission performance.

84 Fed. Reg. at 32552. The following sections discuss how all of the tasks discussed above can be integrated into a final standard of performance that properly accounts for the many forms of variability.

6.1 Task 1 – Baseline Establishment

The first task is to determine the "baseline" that is being used. As discussed in Section 3.1, state regulatory authorities may use a long-term average, such as 3 years, they can use a series of periods that are representative of future conditions, or, if that is not possible, they can project based on the future utilization, so long as that projection is justified in the state plan. The baseline will likely be specific to each EGU. Finally, the same emissions measurement methodology should be used, if possible, for both the baseline and future compliance demonstrations to reduce disparity due to differences in measurement approach.

The outcome of this task is a baseline rate that is an emission rate over a defined averaging period or a series of emission rates based on load, seasons, or other factors.

6.2 Task 2 – BSER HRI Technology Review

The second task determines the potential impact of each BSER HRI technology on the selected baseline. EPA made clear that states are not required to evaluate the myriad potential HRI measures for every regulated facility in its state; rather, "[t]he EPA stated in the proposal that it believed that requiring a state in developing its plan to evaluate the applicability to each of its sources of the entire list of potential HRI options – including those with limited applicability and with negligible benefits – would be overly burdensome to the states."[17] ACE identifies those HRI measures it considers to be the "most impactful" and requires evaluation in State Plans of seven specific technologies included in EPA "Table 1"[18]:

> The degree of emission limitation achievable through application of the BSER (*i.e.,* the ranges of improvements in Table 1) should be used by the states in establishing a standard of performance; however, **the standard of performance calculated for a specific designated facility may ultimately reflect a degree of emission limitation achievable through application of the BSER outside of the EPA's ranges because of consideration of source-specific factors.**

The state plan submission must identify: (1) The value of HRI (i.e., the degree of emission limitation achievable through application of the BSER) for the standard of performance established for each designated facility; (2) the calculation/methodology used to derive such value; and (3) any relevant explanation of the calculation that can help the EPA to assess the plan. In explaining the value of

[17] *See* 84 FED. REG. at 32,536.
[18] *See id.* at 32,537 Table 1.

HRI that has been calculated, if the value of the HRI falls outside the range identified by the EPA for a particular BSER HRI technology, a state must justify that variance as part of its explanation. The state or permitting authority must be careful to ensure that each of the three enumerated items are included in its plan.

The outcome of this task will be an anticipated range and most likely value for each BSER HRI technology and possibly for the group of BSER HRI technologies for the affected EGU.

6.3 Task 3 – BSER HRI Degradation Evaluation

The third task is to consider any degradation in the performance of the BSER HRI technology over time. The state or permitting authority will need to consider whether the BSER HRI technology will be applied continuously (as some O&M might be), once (as an economizer upgrade might be), or repetitively. If the BSER HRI technology will be applied repetitively, then the cost of each iteration, appropriately discounted, needs to be included in the cost evaluation. Looking at the resulting decline curves, the state or permitting authority must decide whether to use an average limit over a set period, which addresses the decline or to set limits for various points along the decline curve, with appropriate demonstration at those points.

The outcome of this task will be, if appropriate, a decline curve for both “intra” averaging period efficacy loss, which will be addressed in setting the standard for the averaging period, and “inter” averaging period efficacy loss, which reflects long-term loss of efficacy, which will be addressed, if necessary, by setting a standard that varies over time with the efficacy loss, likely as a series of standards for set periods over the remaining useful life of the unit.

6.4 Task 4 – “Other Factors” Evaluation

The fourth task is to determine if other factors, such as prior installation, future load, cost, remaining useful life, or any other relevant factor, would cause an improvement outside of the anticipated EPA Table 1 range. For example, EPA gives an example of a source that installed an BSER HRI technology shortly before the evaluation and, as a result, repeating that BSER HRI technology creates little benefit. Similarly, a state regulatory authority could find that a technology is unreasonably expensive in comparison to the cost of other BSER HRI technologies or in comparison to other the cost incurred by other EGUs subject to the standard.

The critical issue throughout this task is that the state or permitting authority identify and document the baseline, how each BSER HRI technology was applied to that baseline, why the state chose to include, exclude or adjust the anticipated effect of the BSER HRI technology and any other factors that the state considered and how and why it adjusted the resulting rate.

The outcome of this task is any adjustment to the BSER HRI technology effects in Task 2 and corresponding changes to any decline adjustment in Task 3.

6.5 Task 5 – Integrating Prior Tasks into a Final Standard of Performance

Task 5 is to take the rate baseline emission rate determined in Task 1 and adjust it by the factors in Tasks 2 through 4 using the adjustment procedure described below. Remember: the baseline rate may be a long-term average, seasonal, load-based or possibly another form and should state whether it is on a net or gross basis.

The first step in this process is integrate the improvement, if any, from each BSER HRI technology in Task 2 with the decline curve in Task 3, if any, for each compliance period (each averaging period during which the EGU will be expected to demonstrate compliance) and determine the effect in terms of the baseline rate (i.e., long-term average, seasonal, load-based, or other form).

The second step will integrate any "other factors" from Task 4 into this analysis.

The third step will integrate all of the BSER HRI technologies and their decline curve into a single best estimate emission rate and to determine whether the standard of performance needs to be broken into periods due to the impact of the degradation analysis in Task 3, if any, or other factors in Task 4. If so, appropriate periods should be selected, and a base standard of performance stated for each period. If this value has been calculated in terms of heat rate it will need to be converted to an emissions rate using factors unique to that EGU.

The outcome of this task is possibly a single standard of performance, a seasonal or load-based standard of performance, a series of load-bin standards, or other appropriate form. If degradation effects are significant, the standard of performance may be a time-bound series starting at the effective date and running through the remaining useful life of the affected EGU, with each relevant time period have a specified standard.

Depending on how many BSER HRI technologies are previously adopted by an affected EGU it is possible that the outcome of this task is a standard of performance emissions rate that does not vary significantly from the baseline emissions rate.

7.0 MONITORING, RECORDKEEPING AND REPORTING

EPA regulations and guidance state "You must include in your plan all applicable monitoring, reporting and recordkeeping requirements for each designated facility and the requirements must be consistent with or no less stringent than the requirements specified in §60.5785a." 40 C.F.R. § 60.6735a. Section 60.5795a states:

> (a) Your plan must include monitoring, recordkeeping, and reporting requirements for designated facilities. To satisfy this requirement, you have the option of either:
>
> (1) Specifying that sources must report emission and electricity generation data according to part 75 of this chapter; or
>
> (2) Including an alternative monitoring, recordkeeping, and reporting program that includes specifications for the following program elements:
>
> (i) Monitoring plans that specify the monitoring methods, systems, and formulas that will be used to measure CO_2 emissions;
>
> (ii) Monitoring methods to continuously and accurately measure all CO_2 emissions, CO_2 emission rates, and other data necessary to determine compliance or assure data quality;
>
> (iii) Quality assurance test requirements to ensure monitoring systems provide reliable and accurate data for assessing and verifying compliance;
>
> (iv) Recordkeeping requirements;
>
> (v) Electronic reporting procedures and systems; and
>
> (vi) Data validation procedures for ensuring data are complete and calculated consistent with program rules, including procedures for determining substitute data in instances where required data would otherwise be incomplete.

40 C.F.R. § 60.5785a. Based on this provision, state regulatory authorities may use existing Part 75 data to determine compliance with the standard of performance, with provisions providing for how the data will be used, or may specify alternative monitoring, recordkeeping, and reporting programs.

If a state regulatory authority is going to use Part 75 data, then it makes sense for the state or permitting authority to use that data as the foundation for determining its baseline and BSER HRI technology comparisons and then to determine compliance using the same Part 75 mechanism. This approach likely works well if longer term averages are being used, as the average CO_2 emissions in pounds may be directly compared to the reported electric generation rate, either gross or net, and the long-term average calculated and compared to the standard of performance. If this alternative is chosen, the state would specify the monitoring period, the averaging method, and whether it is rolling or block averages, and the records to be kept and reported.

If a state elects to proceed using a load bin approach, it could take Part 75 data to establish the baseline rate for each load bin, complete the two-step process, and develop a rate applicable to each bin. The Part 75 data could then be tagged with the appropriate bin and the values compared to demonstrate compliance on a periodic basis. The state would need to specify how often compliance is determined, whether it is rolling or block, and the records to be kept and submitted. Facility data acquisition and handling systems (DAHS) may require revision to accommodate a load bin scheme.

If a state regulatory authority would like to elect to use CEMS, finds that future operations will be similar to past operations, but with more startups and shutdowns due to renewables or other actors, yet believes that the load bin approach is too complex, it could establish one standard of performance applicable during startup and shutdown periods and another during all other periods. If this approach were chosen, the state regulatory authority could look at the impact of startups and shutdowns discussed in Section 3.3.5 for a process to establish and justify the startup/shutdown rate as part of its state plan submittal. The state plan would need to define the startup and shutdown periods subject to the alternative standard of performance.

If a state elects to proceed with a full load compliance approach, it could do so using Part 75 systems for discrete periods at specified loads and conditions and determine compliance based upon those periods. So long as the testing periods, conditions and record retention and reporting requirements are clear, this approach appears to satisfy EPA's requirements. This approach could also be used if the state proposed to use seasonal testing or periodic testing along the load curve. In these cases, the seasonal times at which the test is to be conducted, the applicable limit, test duration and averaging, and the records and reports to be made would need to be specified. For a controlled load approach, the state would specify when the periodic load tests are to be conducted, their duration, conditions, averaging, and how the records and reports are to be made.

If the state elects not to use the Part 75 system, as it might for either a full load, seasonal testing, or periodic load testing standard, then it would need to specify monitoring conditions, recordkeeping and reporting meeting Section 60.5785a(a)(2) requirements.

8.0 COMPLIANCE FLEXIBILITIES

In determining what compliance flexibilities to build into its state plan, the state regulatory authority should consider the following:

1. The state plan should not restrict affected coal-fired EGUs to the BSER HRI technologies but should allow an affected coal-fired EGU to use any measure or set of measures available to it to comply. This issue is discussed in Section 8.1
2. The state plan should seek to avoid requiring a plan revision for adjustments to the standard of performance that are reasonably foreseeable and consistent with the BSER and standard of performance. This issue is discussed in Section 8.2.
    a. If the state plan uses a net basis approach, then it will likely need to provide for adjustments in auxiliary loads at the coal-fired EGU or its support facilities that will affect the CO_2 lb./MWh emission rate. This issue is discussed in Section 8.2.1
    b. Regardless of whether a state plan sets limits on a gross or net basis, there are certain changes that may affect the achievable heat rate. Two examples are a change in compliance instrumentation and a change in coal supply. This issue is addressed in section 8.2.2.
3. Alternative dispatch cycles, which should be considered as part of initial plan development and carried as adjustment factors to the final standard of performance. A possible approach is discussed in section 8.3.
4. Unlike typical industrial sources, electric generating units support the electric grid, which supports numerous residences, businesses, hospitals and other emergency services. Under utility laws and regulations, there may be times when units "must run" to maintain the grid. This can occur when other generation resources are impacted, such as a catastrophic failure at another unit. State plans should provide an allowance for this contingency. A possible approach is discussed in section 8.4.

8.1 No Restriction on Measures Used to Comply

EPA is clear that while the state or permitting authority sets the standard of performance, the source is free to adopt whatever mix of technologies and measures it deems best to demonstrate compliance. As EPA stated:

> To the extent that a state develops a standard of performance based on the application of the BSER for a designated facility within its jurisdiction, **sources should be free to meet that standard of performance using either BSER technologies or certain non-BSER technologies or strategies**. Thus, a designated facility may have broad discretion in meeting its standard of performance within the requirements of a state's plan. For example, **there are technologies, methods, and/or fuels that can be adopted at the designated facility to allow the source to comply with its standard of performance that were not determined to be the BSER, but which may be applicable and prudent for specific units to use to meet their compliance obligations**. Examples of non-BSER

> technologies and fuels include HRI technologies that were not included as candidate technologies, CCS, and natural gas co-firing.

84 Fed. Reg. at 32555. EPA did provide, however, that any such measures a source uses (1) must be capable of being applied to and at the source and (2) must be measurable at the source using data, emissions monitoring equipment, or other methods to demonstrate compliance, such that they can be easily monitored, reported and verified. *Id.* Based on these criteria, EPA ruled out averaging and trading between units and biomass co-firing. *See* 84 Fed. Reg. at 32555-58.

8.2 Adjustment of Standard of Performance

States should give strong consideration to developing their state plan in such a way that the standard of performance under a given set of circumstances and the actual standard of performance, after considering certain adjustment factors set forth in the plan, is then applied to the specific coal-fired EGU as a federally enforceable permit condition in the EGU's construction permit or operating permit. If this step is not taken and the final BSER standard of performance applicable to the source is directly stated in the state plan without adjustment factors, neither the source nor the state will be able to respond to certain reasonably foreseeable events that may render the originally developed standard of performance unworkable without undertaking a full plan revision. While EPA is clear that a state plan may be revised, the reality is that plan revision is a slow process and if the change is due to an unforeseeable event, the source must operate out-of-compliance while the plan revision proceeds, subjecting both the source and the permitting authority to potential lawsuits. The next two subsections address common situations state regulatory authorities and owners/operators should consider.

8.2.1 Standards of Performance Based on Pounds CO_2/MWh net

If a state regulatory authority has determined to set a standard of performance on a net MWh basis, compliance is demonstrated based on the "net" MWh that the unit has available for sale. As a result, changes in in-plant steam or electric demand will affect the EGU's ability to comply. This can occur as a result of the following circumstances that are not necessarily inconsistent with the BSER or the standard of performance:

- Addition of air pollution control equipment, such as an ESP or scrubber, that requires electrical energy to run and thus decreases the net MWh per MMBtu of heat input.
- Retirement of another unit at the same plant, requiring more of the total plant electrical or steam generation load to be carried by the remaining unit(s), thus decreasing the net MWh per MMBtu of heat input from each remaining unit.

In both cases, the EGU itself is continuing to perform as expected and consistent with the BSER evaluation and standard of performance but changes elsewhere in the plant may cause the unit to fall out of compliance. In the two cases cited above, and potentially others cited to the state during the state plan development process, it would be appropriate to provide for an adjustment to the originally developed rate due to the change in circumstances.

The adjustment factor in this case is fairly simple. Since what has changed is the plant steam or electric load, the relationship of the new to the old standard can be expressed as a percentage change or a change in the number of MWh:

New standard of performance = (new/old net MWh) * old standard of performance

The state plan would provide for this adjustment and either automatic adjustment of the standard of performance or adjustment upon application to the state.

8.2.2 Adjustment Factors for All Standards of Performance

In addition to the adjustment factor needed to specifically address changes in net plant steam or electrical parasitic load, several other adjustment factors likely will be needed to keep the program workable over the remaining useful life of the coal-fired EGUs regardless of whether the standard is set on a gross or net basis. These include:

1. **Coal adjustment factor**. The efficiency of any coal-fired steam generating unit is dependent upon the coal that it is firing. Two coals that are superficially similar, but have different % moisture, will have different efficiencies because the "wetter" coal must expend some of its energy to vaporize the additional water. Fortunately, this issue usually occurs with some advance notice due to most coal units carrying several weeks of coal in inventory. The new coal's performance can be compared to the old coal's performance by testing under identical conditions:

   New standard of performance = (new coal test/old coal test) * old standard of performance

   If the state plan established multiple load bins or ranges, the test can be repeated at the various bins or points on the range. A seasonal approach could be addressed by determining the impact on the current seasonal factor at the point of time the test is run and then adjusting the other seasonal factors accordingly.

   This approach can also be used to adjust for coal seam changes within a mine mouth plant.

2. **Instrumentation changes**. Part 75 has a number of detailed steps to ensure accuracy and precision. Nevertheless, the experience of the industry has been that changes in significant portions of the monitoring system may cause a "step change" in the results reported by the monitoring system. This type of step change occurs most commonly with an analyzer replacement but may also change when flow measurement methodology is adjusted. Because it is foreseeable that such changes will occur during the remaining useful life of a

unit, an adjustment factor for this occurrence is necessary. The approach for adjustment is the same as for the coal adjustment factor:

New standard of performance = (new instrument test/old instrument test) * old standard of performance

Both prior adjustment factors are potentially applicable to all coal-fired EGUs and should be strongly considered for inclusion in a state program. In the two cases cited above, and potentially others cited to the state during the state plan development process, it would be appropriate to provide for an adjustment to the originally developed rate due to the change in circumstances.

8.3 Change in Duty Cycle/Dispatch

While state regulatory authorities and operators will undoubtedly give consideration to the duty cycle/dispatch of the unit in developing the "future use" evaluation of the unit through 2035, it is possible that unanticipated developments may alter the proposed use of the facility from one principal dispatch mode, such as base load, to a load following, seasonal, or deep cycling, particularly as more renewable resources are brought on-line. As outlined in prior sections of this report, the efficiency of operation in these alternative duty cycles varies and startups, in particular, have an adverse effect on efficiency.

Based on these considerations, state regulatory authorities and operators may wish to consider likely alternative dispatch modes and how the standard of performance under each of these modes would differ from the base mode established in the final standard of performance. The state plan could then include an adjustment factor that could be claimed by the source if it needs to enter into one of these alternative modes and approved by the state if the designated criteria are met. A state regulatory authority adopting such an approach, or an operator proposing one, would need to build the following into the state plan:

- An identification of the base dispatch cycle, following all applicable EPA guidance.
- An identification of the alternative dispatch cycle, criteria for identifying when the EGU is switching/has switched from one cycle to another, the impact of the switch on the final standard of performance, and the approved adjustment factor(s) applicable if the switch is made, with justification for how the adjustment factors were determined.
- Additional recordkeeping and reporting requirements to implement tracking of the duty/dispatch cycle.

States may also be able to partially address this situation by calculating the estimated number of startups for the base cycle, the efficiency impact per additional startup, and providing an adjustment factor for a unit that undergoes additional, unanticipated startups. Another alternative a state may consider is setting different standard of performance rates for normal operation and startup/shutdown periods, as discussed in Section 7.0.

8.4 "Must Run" and Grid Reliability

Unlike typical industrial sources, EGUs support the electric grid that supports residences, businesses, hospitals and other critical community services. Under the rules of various regulatory bodies, EGUs may be placed in a "must run" situation due to the need to maintain grid reliability. The state plan should recognize this and provide a mechanism that allows a unit to run in such a situation.

The ACE rule, with its focus on an emission rate based on what the EGU can achieve, is better able to accommodate these situations then the former Clean Power Plan rule, which relied more heavily on generation shifting. Nevertheless, there may be times when a unit may be required to run over a planned maintenance period and, as a result, its carbon emissions performance may deteriorate below the limit established in the state plan. If the state has adopted an averaging approach for setting the standard of performance, with compliance demonstrated by the "average" emissions achieved, this can create a problem.

EPA is clear that carbon emissions are a long-term problem and that short fluctuations are not of environmental concern so long as the overall reduction is achieved. Based on this consideration, it is recommended that if the average performance of the unit as determined below meets the standard, the environmental objective is met and the unit should be judged in compliance.

For such situations, it is recommended that states provide a reasonable period for operation under "must run" conditions, which should be a period long-enough for the operator or grid operator to identify alternative energy supply or grid support mechanisms. During this time, compliance would be demonstrated by looking to the best equivalent period in the same major maintenance cycle for the unit. Compliance during the deferred maintenance, "must run" condition would then be determined as follows:

$$\text{DMMR rate} = (\text{Sum}_i\,(\text{ER}_i * \text{MWh}_i) + j * (\text{ER}_{javg} * \text{MWh}_{javg}) \,/\, (\text{Sum MWh}_i + (j * \text{MWh}_{javg})$$

Where:

DMMR rate = rate during deferred maintenance, must run period. The period starts when a unit under a "must run" order defers a maintenance activity anticipated in the state plan and ends when any of the following occur: the maintenance is performed; the must run period ends, or the end of the "reasonable period" occurs, whichever comes first.

i = hour, up to the "reasonable period," during deferred maintenance, "must run" period

ER_i = Emission rate during hour i, in units of standard of performance

MWh_i =	Megawatt hours generated during hour i, in units of standard of performance
j =	number of hours in best six months in current major maintenance cycle, where j = I, unless there are more hours in i than in j, in which case j = j.
ER_{javg} =	Average emission rate during best equivalent period in the current or prior major maintenance cycle, in units of the standard of performance
MWjavg =	Average MWh per operating hour during best equivalent period in the current or prior major maintenance cycle, in units of standard of performance

The proposed approach, which averages performance of the unit under must run conditions over the end of its planned maintenance cycle for a limited duration and demonstrates that the overall performance complies with the standard of performance, should fulfill program objectives while providing relief for "must run" situations while minimizing potential collateral consequence, such as power outages, on third parties.

If the state regulatory authority were to adopt this approach, it would need to determine the "reasonable period" during which "must run" conditions and deferred maintenance likely jeopardizing compliance could occur and the likely time needed before the owner/operator or grid operator could otherwise satisfy the "must run" condition. This time could be substantial on grid sections with limited supply units or interconnections. For example, twenty-four months may be a reasonable worst-case scenario for an EGU losing a high-pressure feedwater heater because the lead time may be 12 to 18 months plus installation time. CO_2 emissions will increase without the feedwater heater, but if no other adequate generation resource is available, the owner/operator or grid operator may have little choice but to continue to operate the EGU.

9.0 CONCLUSION

The engineering and operations issues and possible approaches for solutions outlined in this guidance are not designed to discourage state regulatory authorities and owner/operators, but to encourage them to think through these issues up front with an understanding of the engineering challenges involved. It may turn out that an appropriate state plan cannot merely specify a single standard of performance with periodic tests or continuous monitoring. Instead, a good state plan must reflect the exercise of engineering judgment to evaluate multiple factors in assessing the proper standard of performance. The following principles are recommended for considering in designing the state plan:

- It is possible that a range of limits will be needed to reflect changes over time.
- Long term averaging times may be appropriate because there are no short-term health effects, unlike a traditional air pollution control standard. Long-term averaging times, likely a year or more, may be helpful in lessening the variability discussed in this document. Alternatively, consistent testing in the same season could be considered to minimize bias from differing ambient conditions.
- An adjustment mechanism likely may be needed to reflect changes in fuel quality and changes in monitoring instruments, market conditions or other conditions over the life of affected coal-fired EGU operation.
- State plans should use good combustion and O&M practices as a primary determinant of continuous compliance.
- State plans should have safety valves designed to allow coal-fired EGUs to operate to maintain grid reliability and stability to support this transition, subject to reasonable tuning and/or recapture requirements after such an emergency event.

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