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U.S. Energy Information Administration

Analysis of Heat Rate Improvement Potential at Coal-Fired Power Plants

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Introduction

The thermal efficiency of electricity production is represented by the heat rate, which measures the amount of energy used to generate one kilowatthour of electricity.[1] A generating unit with a lower, or more efficient, heat rate can generate the same quantity of electricity while consuming less fuel, compared with a unit with a higher heat rate. Lower fuel use per unit of electricity generated also reduces the corresponding emissions of pollutants such as sulfur dioxide (SO_2), nitrogen oxide (NO_X), mercury (Hg), and carbon dioxide (CO_2). Consequently, improving heat rates at power plants can lower fuel costs and help achieve compliance with environmental regulations.

During the development of the Annual Energy Outlook 2015 (AEO2015), the U.S. Energy Information Administration (EIA) updated its modeling capability to include the ability to evaluate the potential for making heat rate improvements at existing coal-fired generators. The projections in the AEO2015 are produced by the National Energy Modeling System (NEMS), which is a modular system consisting of components to represent fuel supply, end-use consumption and conversion sectors, as well as modules for international and macroeconomic activities.

The Electricity Market Module (EMM) is the electricity supply component of the NEMS. The EMM performs three primary functions – capacity planning, fuel dispatching, and finance and pricing. Capacity planning decisions include building new plants to satisfy increases in demand and to replace retiring plants. Planning decisions also consider retrofits of existing capacity to install pollution control devices. The fuel dispatching function involves operating the available capacity to meet the demand for electricity. The finance and pricing function considers the investment costs associated with planning decisions and the operating costs from dispatching activities to develop delivered prices for electricity.

Heat rate improvement is another planning activity, as it considers the tradeoff between the investment expenditures and the savings in fuel and/or environmental compliance costs. Potential increases in efficiency can vary depending in part on the type of equipment installed at a generating plant. The EMM represents 32 configurations of existing coal-fired plants based on different combinations of particulate, sulfur dioxide (SO_2), nitrogen oxide (NO_X), mercury, and carbon emission controls (Table 1). These categories form the basis for evaluating the potential for heat rate improvements.

EIA entered into a contract with Leidos Corporation (Leidos) to develop a methodology to evaluate the potential for heat rate improvement at existing coal-fired generating plants. Leidos performed a statistical analysis of the heat rate characteristics of coal-fired generating units modeled by EIA in the EMM. Specifically, Leidos developed a predictive model for coal-fired electric generating unit heat rates as a function of various unit characteristics.[2] Leidos employed statistical modeling techniques to create the predictive models.[3]

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[1] U.S. Energy Information Administration, Frequently Asked Questions, What is the efficiency of different types of power plants?, accessed January 31, 2015.

[2] The characteristics used to predict heat rate included attributes such as nameplate capacity, rank of coal used, NEMS plant type, flue-gas desulfurization status, and flue-gas particulate collector type.

[3] This included algorithmic evaluation of potential descriptive variables, and piecewise linear regression analysis. A decision tree created 7 sub-models describing inputs for the heat rate model for different unit categorizations.

For the EMM plant types, the coal-fired generating units were categorized according to quartiles, based on observed[4] versus predicted heat rates. Units in the first quartile (Q1), which perform better than predicted, were generally associated with the least potential for heat rate improvement. Units in the fourth quartile (Q4), representing the least efficient units relative to predicted values, were generally associated with the highest potential for heat rate improvement. Leidos developed a matrix of heat rate improvement options and associated costs, based on a literature review and the application of engineering judgment.

Little or no coal-fired capacity exists for the EMM plant types with mercury and carbon control configurations, therefore estimates were not developed for those plant types. These plant types were ultimately assigned the characteristics of the plants with the same combinations of particulate, SO_2, and NO_x controls. Plant types with relatively few observations were combined with other plant types having similar improvement profiles. As a result, 9 unique plant type combinations were developed for the purposes of the quartile analysis, and for each of these combinations Leidos created a minimum and a maximum potential for heat rate improvement along with the associated costs to achieve those improved efficiencies.[5]

Leidos used the minimum and maximum characteristics as a basis for developing estimates of mid-range cost and heat rate improvement potential. The mid-range estimates were used as the default values for the Annual Energy Outlook 2015 (AEO2015) (Table 2). Table 3 contains the minimum and maximum heat rate improvements and costs.

Additional details regarding the background and the analytical methodology are included in the consultant report prepared by Leidos Corporation (Appendix).

[4] In this report, observed heat rates refer to the heat rates contained in EIA's EMM plant file.

[5] Leidos selected the plant type and quartile groupings such that each grouping contained at least 10 generating units, with the exception of the integrated gasification combined-cycle (IG) type, which has essentially no heat rate improvement potential. Some plant types and quartiles also had associated variable operation and maintenance (O&M) costs. The variable O&M costs were not incorporated into the NEMS EMM model at the time of this analysis. However, the impact of omitting variable O&M cost is expected to be small due to the relative magnitude of the capital and fixed O&M cost components.

Table 1: Existing pulverized coal plant types in the NEMS Electricity Market Module

Plant type	Particulate controls	SO2 controls	NOX controls	Mercury controls	Carbon controls
B1	BH	None	Any	None	None
B2	BH	None	Any	None	CCS
B3	BH	Wet	None	None	None
B4	BH	Wet	None	None	CCS
B5	BH	Wet	SCR	None	None
B6	BH	Wet	SCR	None	CCS
B7	BH	Dry	Any	None	None
B8	BH	Dry	Any	None	CCS
C1	CSE	None	Any	None	None
C2	CSE	None	Any	FF	None
C3	CSE	None	Any	FF	CCS
C4	CSE	Wet	None	None	None
C5	CSE	Wet	None	FF	None
C6	CSE	Wet	None	FF	CCS
C7	CSE	Wet	SCR	None	None
C8	CSE	Wet	SCR	FF	None
C9	CSE	Wet	SCR	FF	CCS
CX	CSE	Dry	Any	None	None
CY	CSE	Dry	Any	FF	None
CZ	CSE	Dry	SCR	FF	CCS
H1	HSE/Oth	None	Any	None	None
H2	HSE/Oth	None	Any	FF	None
H3	HSE/Oth	None	Any	FF	CCS
H4	HSE/Oth	Wet	None	None	None
H5	HSE/Oth	Wet	None	FF	None
H6	HSE/Oth	Wet	None	FF	CCS
H7	HSE/Oth	Wet	SCR	None	None
H8	HSE/Oth	Wet	SCR	FF	None
H9	HSE/Oth	Wet	SCR	FF	CCS
HA	HSE/Oth	Dry	Any	None	None
HB	HSE/Oth	Dry	Any	FF	None
HC	HSE/Oth	Dry	Any	FF	CCS

Notes: Particulate Controls, BH – baghouse, CSE = cold side electrostatic precipitator,
HSE/Oth = hot side electrostatic precipitator/other/none;
SO2 Controls - wet = wet scrubber, Dry = dry scrubber;
NOx Controls, SCR = selective catalytic reduction;
Mercury Controls - FF = fabric filter;
Carbon Controls - CCS = carbon capture and storage.
Source: U.S. Energy Information Administration/Leidos Corporation.

Table 2: Heat rate improvement (HRI) potential and cost (capital, fixed O&M) by Plant Type and quartile as used for input to NEMS

Plant type and quartile combination	Count of total units	Percentage HRI potential	Capital cost (million 2014 $/MW)	Average fixed O&M cost (2014 $/MW-yr)
B1-Q1	32	(s)	0.01	200
B1-Q2	15	0.8%	0.10	2,000
B1-Q3	18	4%	0.20	4,000
B1-Q4	20	6%	0.90	20,000
B3-Q1	13	(s)	0.01	300
B3-Q2	24	0.7%	0.05	1,000
B3-Q3	16	6%	0.20	3,000
B3-Q4	15	9%	0.60	10,000
B5C7-Q1	16	(s)	(s)	80
B5C7-Q2	42	0.8%	0.03	700
B5C7H7-Q3	84	7%	0.10	2,000
B5C7H7-Q4	59	10%	0.20	4,000
B7-Q1	27	(s)	(s)	70
B7-Q2	25	0.8%	0.04	800
B7-Q3Q4	30	7%	0.30	5,000
C1H1-Q1	148	(s)	0.01	200
C1H1-Q2	117	0.8%	0.10	2,000
C1H1-Q3	72	4%	0.40	8,000
C1H1-Q4	110	7%	1.00	30,000
C4-Q1	15	(s)	(s)	80
C4-Q2	27	0.8%	0.04	900
C4-Q3	32	6%	0.20	2,000
C4-Q4	39	10%	0.30	5,000
CX-Q1Q2Q3Q4	15	7%	0.20	4,000
H4-Q1Q2Q3	13	3%	0.20	3,000
IG-Q1	3	(s)	(s)	60
Total set	**1,027**	**4%**	**0.30**	**6,000**

(s) = less than 0.05% for HRI potential or less than 0.005 million $/MW for capital cost.
Source: U.S. Energy Information Administration/Leidos Corporation.

Table 3: Minimum and maximum heat rate improvement (HRI) parameters

Plant type and quartile combination	Count of total units	Percentage HRI potential	Capital cost (million 2014 $/MW)
B1-Q1	32	(s)	0.007
B1-Q2	15	0.3% - 1.2%	0.096 - 0.11
B1-Q3	18	2.1% - 6.4%	0.20 - 0.26
B1-Q4	20	3.5% - 9.4%	0.76 - 0.99
B3-Q1	13	(s)	0.01
B3-Q2	24	0.3% - 1.2%	0.047 - 0.056
B3-Q3	16	3.1% - 8.2%	0.19 - 0.30
B3-Q4	15	5.1% - 13%	0.50 - 0.72
B5C7-Q1	16	(s)	0.003
B5C7-Q2	42	0.3% - 1.2%	0.031 - 0.036
B5C7H7-Q3	84	3.6% - 9.5%	0.11 - 0.16
B5C7H7-Q4	59	6.0% - 15%	0.18 - 0.25
B7-Q1	27	(s)	0.002
B7-Q2	25	0.3% - 1.2%	0.035 - 0.042
B7-Q3Q4	30	3.8% - 9.8%	0.27 - 0.40
C1H1-Q1	148	(s)	0.006
C1H1-Q2	117	0.3% - 1.2%	0.12 - 0.13
C1H1-Q3	72	2.0% - 6.0%	0.36 - 0.49
C1H1-Q4	110	3.6% - 9.6%	1.1 - 1.5
C4-Q1	15	(s)	0.002
C4-Q2	27	0.3% - 1.2%	0.041 - 0.048
C4-Q3	32	3.5% - 9.1%	0.13 - 0.20
C4-Q4	39	5.7% - 14%	0.21 - 0.30
CX-Q1Q2Q3Q4	15	3.7% - 9.7%	0.19 - 0.28
H4-Q1Q2Q3	13	1.9% - 5.1%	0.14 - 0.21
IG-Q1	3	(s)	0.002
Total set	**1,027**	**2.0% - 5.3%**	**0.24 - 0.32**

(s) = less than 0.05% for HRI potential.

Source: U.S. Energy Information Administration/Leidos Corporation.

Appendix – Full Report

Evaluation of the Potential for Heat Rate Improvements at Coal-Fired Power Plants

EIA Task 7965, Subtask 14

Prepared for:

Energy Information Administration

Office of Energy Analysis

Office of Electricity, Coal, Nuclear and Renewables Analysis

Prepared by:

Leidos Corporation

Ken Walsh, Dave Lesneski, Carl Thomason, Jay Ratafia-Brown

FINAL REPORT

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Table of Contents

List of Tables

List of Figures

List of Abbreviations and Acronyms

AEO	Annual Energy Outlook
AMPD	Air Markets Program Data
ASME	American Society of Mechanical Engineers
Btu	British thermal units
CAMD	Clean Air Markets Division
CO	Carbon monoxide
CO_2	Carbon dioxide
DCS	Distributed control system
ECP	Electricity Capacity Planning
EFD	Electricity Fuel Dispatch
EGU	Electricity Generating Unit
EIA	Energy Information Administration
EMM	Electricity Market Module
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
ESP	Electrostatic precipitator
FDS	Fuel delivery system
FGD	Flue gas desulfurization
FGP	Flue gas particulate
GMOD	GHG Mitigation Options Database
GWh	Gigawatt-hours
HRI	Heat rate improvement
$K	Thousand dollars
kWh	Kilowatt-hours
LP	Low pressure
M5P	A numeric classifier algorithm within Weka data mining software
$M	Million dollars
MWh	Megawatt-hours
NEMS	National Energy Modeling System
NETL	National Energy Technology Laboratory
NO_X	Oxides of nitrogen
NPC	Nameplate capacity
NSR	New Source Review
O&M	Operating and maintenance
R&D	Research and development
S&L	Sargent & Lundy
SCR	Selective catalytic reduction
TC	Total costs
TPFS	Total potential fuel savings
U.S.	United States

List of Energy Information Administration ECP Types

For the database within this study, EIA assigned twelve codes to coal-fired electricity generating units for use in the Electricity Capacity Planning (ECP) submodule within the Electricity Market Module (EMM) of the National Energy Modeling System (NEMS). These codes represent the fuel/technology and emission control devices. Because the codes are frequently referenced in this report, the code definitions are included below for coal-fired units (none were listed with carbon capture devices):

Unit Code	Technology	Particulate Control	Flue Gas Desulfurization	Other Controls
B1	Conventional	Baghouse	None	Any NO_x control
B3			Wet	No selective catalytic reduction
B5			Wet	Selective catalytic reduction
B7			Dry	Any NO_x control
C1		Cold-side electrostatic precipitator	None	Any NO_x control
C4			Wet	None
C7			Wet	Selective catalytic reduction
CX			Dry	None
H1		Other or none	None	Any NO_x control
H4			Wet	None
H7			Wet	Selective catalytic reduction
IG	Integrated gasification combined cycle	--	--	--

Executive Summary

The Energy Information Administration's (EIA's) National Energy Modeling System (NEMS) projects annual loads on electric generating units and the years that different types of coal-fired units will retire or implement efficiency improvements based on economic factors. This study evaluated how NEMS might assign heat rate improvements (HRIs) to different coal-fired electric generating units and compute the associated costs within NEMS. Various unit-level HRIs were considered in an effort to match NEMS unit types to particular total improvement levels.

The net heat rates at existing generators were compared to individual numeric parameters from EIA and U.S. Environmental Protection Agency (EPA) records, but the only factor that had a linear correlation coefficient better than 0.60 was the variable operating and maintenance costs as expressed in dollars per megawatt-hour ($/MWh). Despite the influence of many different plant design aspects, the inverse net heat rates (a plant efficiency metric) were clearly dependent (though not linearly) on the nameplate capacities (MW) of the boilers associated with each generator.

Data mining algorithms produced a piecewise linear regression model to describe the behavior at the coal-fired units. Previous studies had yielded Pearson's correlation coefficients (r^2) of 0.18, but the piecewise linear modeling approach in this study improved the r^2 to 0.62 (for predicting inverse heat rates). Figure ES-1 compares the reported and predicted inverse heat rates, and the red dashed lines show slopes corresponding to a 50% confidence interval. The deviations of reported heat rates in 2012 from the modeled values provide benchmarks to differentiate units with HRI potentials from those that are likely already operating very efficiently. The units lying to the left of all three lines in Figure ES-1 were considered to be those that had the most room for improvement relative to similar units. Those to the right of the lines likely would have less HRI potential because they already operate better than similar units (as described by the model).

Fifty-six HRI activities were initially under consideration, but the list was reduced to 29 measures because available HRIs should be considered non-routine activities, should not overlap, and should be beyond the pilot phase of development (in order to allow costing estimates within NEMS). No-cost and low-cost improvements could be made at the plants operating at the lowest efficiencies (Quartile 4) while assuming that other plants had already implemented these. The study also associated moderate- and high-cost HRIs as potential for units that were operating near the modeled heat rate values (Quartiles 2 and 3) but not near the best reported values for similar units (Quartile 1).

Units that went online after 1990 generally offered the smallest HRI potentials; 70% of those units fell into Quartiles 1 and 2, so fewer HRI measures were attached to them. Units going online in the 1970s and 1980s received the earliest air pollution control technologies but have not necessarily been upgraded in their lifetimes. The 1970s/1980s units also include the supercritical units, so their heat rates were competitive with other upgraded units. Because NEMS ECP types[1] categorize the coal-fired units based on emission control technologies, the analyses show that the emission controls at the units with the highest HRI potential are likely to be characterized by a combination of these three factors: wet scrubbers, no use of baghouses or cold-side ESP, and SCR.

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[1] ECP types defined on page vii.

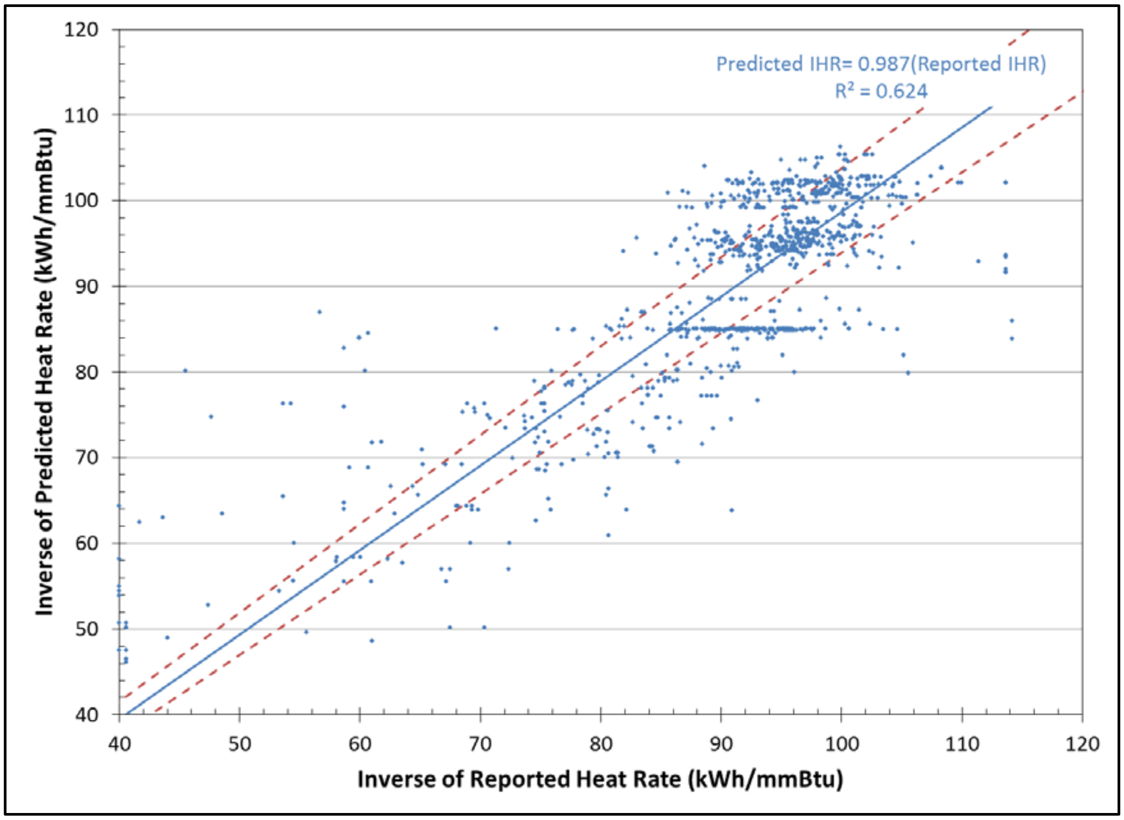

Figure ES-1. Comparison of Reported and Predicted Inverse Heat Rates for All Coal-Fired Generators

Figure ES-2 presents the average new heat rates that might be associated with the average units in each ECP type. The left sides of the bars represent the average heat rates if the maximum HRI potentials are realized with every improvement, and the right sides of the bars represent the resultant heat rates when only the minimum HRIs are achieved. The plot shows that B5, C7, H7 and some C4 units might have heat rates under 10,000 Btu/kWh if the improvements are made. In Figure ES-2, the H1 units would continue to average high heat rates (near 16,000 Btu/kWh) even if the improvements described were all undertaken because EIA's base heat rates for these 21 units are high.

The capital costs can be approximated (r^2=0.90) by multiplying the HRI potential by $100,000-kWh/Btu. However, the total operating and maintenance (O&M) costs are not well estimated by a linear correlation (r^2=0.41). The poor approximations of total O&M costs are tied to the non-linearity associated with one particular HRI measure with high O&M costs. If this one HRI measure is removed from consideration, variable O&M costs drop to just 2% of the total O&M costs and the linearity improves (r^2=0.95 and slope=$1600-kWh/Btu-yr).

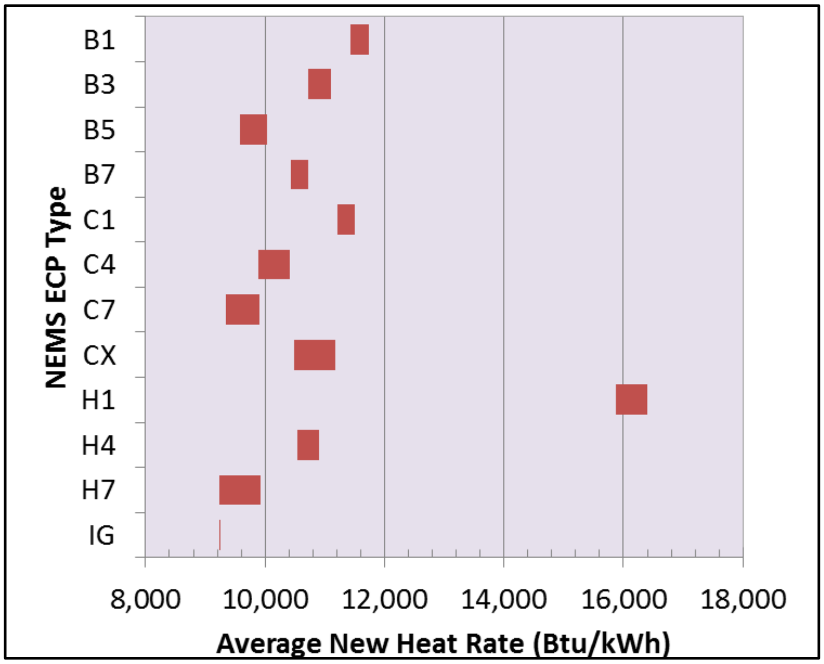

Figure ES-2. Average New Heat Rates by NEMS ECP Type.

1 Introduction

The NEMS Electricity Market Module (EMM) dispatches generating units in economic merit order, subject to numerous constraints. In order for coal-fired generating units to be dispatched in NEMS EMM, all else equal, the associated variable costs must be lower than the variable costs of other generators. A competitive coal-fired plant may need to implement net heat rate improvements in order to remain an economical choice in the model.

The **net heat rate** (Btu/kWh) represents the total heat content of the fuel consumed (based on the higher heating value, HHV) divided by the net electricity generation. The *net electricity generation* is represented by the *gross generation* minus the electricity consumed internally by the plant (e.g., fuel feed systems, boiler feed pumps, pollution control devices, heat recovery equipment, and other auxiliary loads); whereas gross generation for a unit represents the total amount of electric energy as measured *at the generator terminal*.

This study was based on the reference data in the NEMS EMM plant database that EIA provided for this study, as well as information collected from the 2012 EIA-860 survey. An EIA data set of generators that are primarily powered by coal-fired boilers had 2012 net heat rates ranging from 8800 Btu/kWh to 25,000 Btu/kWh. Weighting this information based on the net MWh electricity produced (using EPA CAMD files), the 2012 state averages ranged from 9700 Btu/kWh (North Carolina) to 11,500 Btu/kWh (Delaware), as illustrated in Figure 1-1. These numbers indicate that the North Carolina coal-fired plants are on average 16% more efficient than the Delaware plants. Coal quality and moisture affect the potential heat rates, but this significant range is also influenced by plant design and operations.

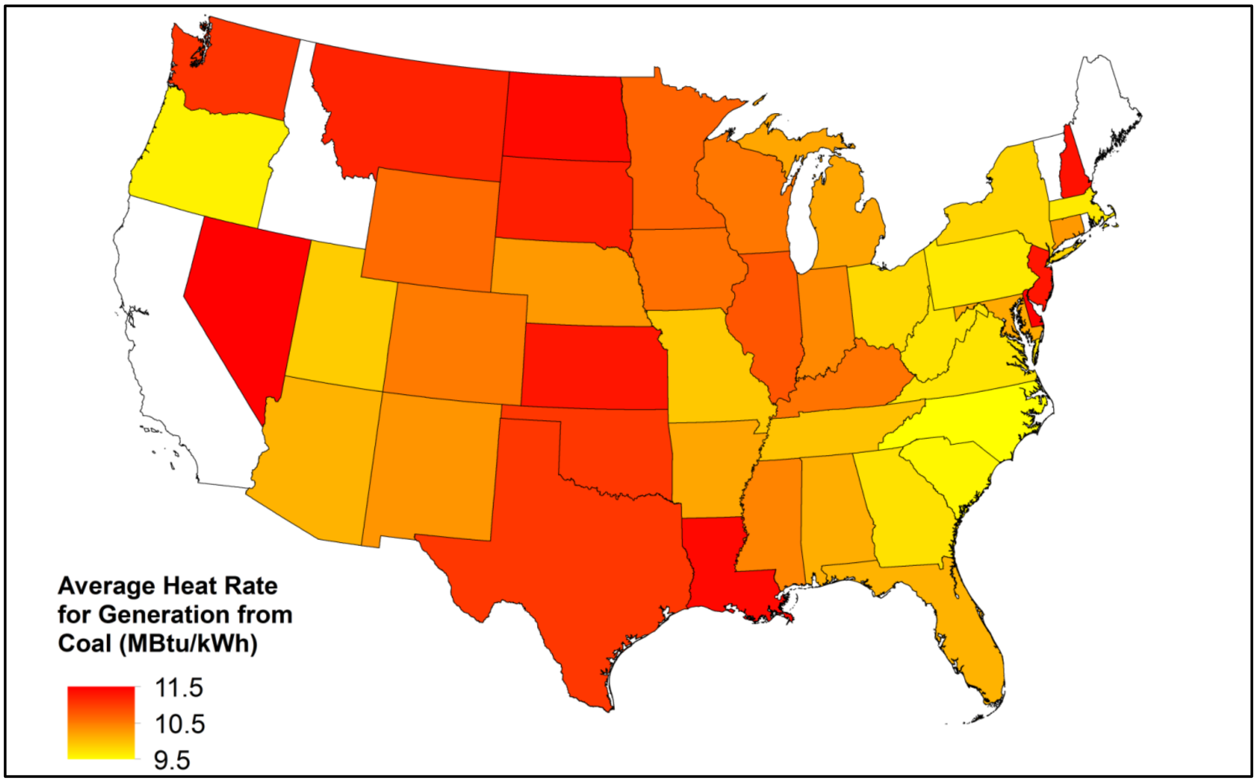

Figure 1-1. Average Heat Rate from Coal-Fired Units (Weighted to Generators Based on 2012 Electricity Production)

EIA and EPA regularly collect information about fuel usage, operations, and emissions at power plants, but modifications that are made to improve the net heat rate are not tracked on a national basis. Improvements for the boiler island, turbine island, flue gas system, air pollution controls, and water treatment system may all affect the net heat rate.

This report discusses one NEMS approach that would allow heat rate improvements (and the associated costs) to be incorporated expeditiously for present and future activities. Chapter 2 lists some resources that published observed heat rate improvements. Chapter 3 describes the processing of an EIA survey data set to determine which coal-fired units are likely already operating as efficiently as possible and which units have more potential for improvement. Chapter 4 shares analyses that indicate how the potential for improvement is related to other plant characteristics. Chapter 5 discusses the possible heat rate improvement measures, their effects, and their costs. Chapter 6 describes the resulting total heat rate improvements associated with the various ECP plant types within NEMS and the associated capital, operating, and maintenance costs. Chapter 7 presents some recommendations for future improvements to the estimates, primarily based on expected new information sources.

2 Literature Review

Some differences in heat rates may be attributed to coal type, moisture content, and boiler sizes, but best practices and technological improvements have also been made at some plants with the goals of decreasing heat rates and subsequently fuel costs. Many heat rate improvements (HRIs) have been made over the last several decades, and the National Energy Technology Laboratory (NETL) summarized the efficiency improvements for existing coal-fired power plants in 2008. In 2014, the U.S. EPA[2] reported these HRIs and the associated efficiencies (reproduced in Table 2-1).

Table 2-1. Existing Coal-Fired EGU Efficiency Improvements Reported for Actual Efficiency Improvement Projects[3]

Efficiency Improvement Technology	Description	Reported Efficiency Increase [a]
Combustion Control Optimization	Combustion controls adjust coal and air flow to optimize steam production for the steam turbine/generator set. However, combustion control for a coal-fired EGU is complex and impacts a number of important operating parameters including combustion efficiency, steam temperature, furnace slagging and fouling, and NO_x formation. The technologies include instruments that measure carbon levels in ash, coal flow rates, air flow rates, CO levels, oxygen levels, slag deposits, and burner metrics as well as advanced coal nozzles and plasma assisted coal combustion.	0.15 to 0.84%
Cooling System Heat Loss Recovery	Recover a portion of the heat loss from the warm cooling water exiting the steam condenser prior to its circulation through a cooling tower or discharge to a water body. The identified technologies include replacing the cooling tower fill (heat transfer surface) and tuning the cooling tower and condenser.	0.2 to 1%
Flue Gas Heat Recovery	Flue gas exit temperature from the air preheater can range from 250 to 350°F depending on the acid dew point temperature of the flue gas, which is dependent on the concentration of vapor phase sulfuric acid and moisture. For power plants equipped with wet FGD systems, the flue gas is further cooled to approximately 125°F as it is sprayed with the FGD reagent slurry. However, it may be possible to recover some of this lost energy in the flue gas to preheat boiler feedwater via use of a condensing heat exchanger.	0.3 to 1.5%
Low-rank Coal Drying	Subbituminous and lignite coals contain relatively large amounts of moisture (15 to 40%) compared to bituminous coal (less than 10%). A significant amount of the heat released during combustion of low-rank coals is used to evaporate this moisture, rather than generate steam for the turbine. As a result, boiler efficiency is typically lower for plants burning low-rank coal. The technologies include using waste heat from the flue gas and/or cooling water systems to dry low-rank coal prior to combustion.	0.1 to 1.7%

[2] U.S. Environmental Protection Agency, *GHG Abatement Measures*, Technical Support Document for *Carbon Pollution Guidelines for Existing Power Plants: Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources: Electric Utility Generating Units*, Docket ID No. EPA-HQ-OAR-2013-0602, June 2014. Downloaded from http://www.eenews.net/assets/2014/06/02/document_gw_04.pdf on December 1, 2014.

[3] *Ibid*.

Efficiency Improvement Technology	Description	Reported Efficiency Increase [a]
Sootblower Optimization	Sootblowers intermittently inject high velocity jets of steam or air to clean coal ash deposits from boiler tube surfaces in order to maintain adequate heat transfer. Proper control of the timing and intensity of individual sootblowers is important to maintain steam temperature and boiler efficiency. The identified technologies include intelligent or neural network sootblowing (i.e., sootblowing in response to real-time conditions in the boiler) and detonation sootblowing.	0.1 to 0.65%
Steam Turbine Design	There are recoverable energy losses that result from the mechanical design or physical condition of the steam turbine. For example, steam turbine manufacturers have improved the design of turbine blades and steam seals which can increase both efficiency and output (i.e., steam turbine dense pack technology).	0.84 to 2.6%

Source: U.S. Department of Energy, National Energy Technology Laboratory, *Reducing CO2 Emissions by Improving the Efficiency of the Existing Coal-fired Power Plant Fleet*, DOE/NETL-2008/1329 , Pittsburgh, PA. July 23, 2008. Available at: <http://www.netl.doe.gov/energy-analyses/pubs/CFPP%20Efficiency-FINAL.pdf>.

[a] Reported efficiency improvement metrics adjusted to common basis by conversion methodology assuming individual component efficiencies for a reference plant as follows: 87% boiler efficiency, 40% turbine efficiency, 98% generator efficiency, and 6% auxiliary load. Based on these assumptions, the reference power plant has an overall efficiency of 32% and a net heat rate of 10,600 Btu/kWh. As a result, if a particular efficiency improvement method was reported to achieve a 1% point increase in boiler efficiency, it would be converted to a 0.37 % point increase in overall efficiency. Likewise, a reported 100 Btu/kWh decrease in net heat rate would be converted to a 0.30% point increase in overall efficiency.

However, this report noted the following:

> "The EPA does not have sufficient site specific information to accurately estimate what percentage of the fleet has adopted various HRI methods, nor how effectively, and is not aware of any other investigator having sufficient information."

Despite this lack of detailed information, EPA's method included binning plants into 168 categories and forecasting possible HRIs based on the best 10% of the units.

The 2009 Sargent and Lundy report (S&L Report) quantifies the major retrofits that are not considered cost-prohibitive at existing coal-fired power plants. Activities that were considered cost-prohibitive included coal handling, coal ash handling, and feedwater preheating.[4] This literature review presents findings from the S&L Report (Table 2-2), but focuses on work that has been published since issuance of that report.

The sections below outline additional technologies that can be used to reduce heat rates, as well as studies that describe total possible HRIs. For example, EPRI's Production Cost Optimization project evaluated five units to find 3-5% HRIs through various means.[5] In addition, an EPA technical support document associated with the greenhouse gas emission control measures for power plants discusses possible efficiency gains. For studies that estimate costs associated with these technologies and groups of technologies, the costs are also presented in the final section.

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[4] Hansel, Peter, *Heat Rate Reductions and Carbon Emissions: A Policy Mechanism for Regulating Coal Plants under 111(d) of the Clean Air Act*, April 22, 2014. Downloaded on November 25, 2014, from http://dukespace.lib.duke.edu/dspace/bitstream/handle/10161/8508/Heat%20Rate%20Reductions%20and%20Carbon%20Emissions%20-%20Peter%20Hansel%20MP%20Final.pdf?sequence=1.

[5] Korellis, S., *Range and Applicability of Heat Rate Improvements*, Technical Update, Electric Power Research Institute Report Number 3002003457, April 2014.

Table 2-2. Maximum HRIs and Associated Costs Listed in the 2009 S&L Report

	Heat Rate Improvement (Btu/kWh)			Capital Cost (2008 $M)			Fixed O&M (2008 $K/yr)			Variable O&M (2008 $K/yr)		
	≤200 MW	≤500 MW	>500 MW	≤200 MW	≤500 MW	>500 MW	≤200 MW	≤500 MW	>500 MW	≤200 MW	≤500 MW	>500 MW
Boiler Island Improvements												
Installing economizer	100	100	100	3	5	8	50	100	150	0	0	0
Neural network	150	100	50	0.5	0.8	0.8	50	50	50	0	0	0
Intelligent sootblower	150	90	90	0.3	0.5	0.5	50	50	50	0	0	0
Limit air heater leakage	40	40	40	0.5	0.7	1.2	50	75	100	0	0	0
Lower air heater outlet temperature by controlling acid dew point	120	120	120	3.5	10	18	50	75	100	350	850	1500
Turbine Island Improvements												
Turbine overhaul	300	300	300	12	20	25	0	0	0	0	0	0
Condenser cleaning	70	70	70	0	0	0	30	60	80	0	0	0
Boiler feed pumps	50	50	50	0.35	0.6	0.8	0	0	0	0	0	0
Flue Gas System Improvements												
ID axial fan (and motor) upgrades	50	50	50	6.5	11	16	50	85	130	0	0	0
Variable-frequency drives	100	100	100	2	4	6	20	30	50	0	0	0
Variable-frequency drives and new centrifugal fans	150	150	150	6.5	11	16	25	38	60	0	0	0
Air Pollution Control Improvements												
Removal of Venturi throat	13	13	13	2.5	2.5	2.5	0	0	0	0	0	0
Turning vanes and perforated gas distribution plates at the inlet	2	2	2	0.25	0.25	0.25	0	0	0	0	0	0
Shutoff spray level	16	16	16	--	--	--	0	0	0	0	0	0
Variable-frequency drives	50	50	50	1	3	5	50	100	150	0	0	0
ESP modification	5	5	5	0.2	0.5	0.8	25	25	25	0	0	0
SCR modification	10	10	10	0.5	1	2	25	50	100	25	60	100
Water Treatment Improvements												
Cooling tower advanced packing upgrade	70	70	70	1.5	3	5	75	125	175	0	0	0

2.1 Heat Rate Improvement Technologies

The focus of this literature review is literature published after the S&L Report. Within this section, the literature review divides the technologies among the fuel supply, boiler island, turbine island, and other systems at the plant. One difficulty assessing the efficiency of various HRIs is that multiple improvement measures are undertaken during outages, so individual efficiencies cannot be determined from overall plant measurements.

2.1.1 Fuel Supply

The National Coal Council reports three alternatives for improving thermal efficiency:[6]

1) Coal switching (switch from subbituminous to bituminous fuel could increase thermal efficiency by 1.6%)
2) Coal drying (Great River Energy increased plant net generating thermal efficiency by 4% through lignite drying)
3) Coal processing (adding ammonium hydroxide increased the coal heating value from 7,859 to 11,363 Btu/lb when 24% moisture was removed).

An example comes from the Great River Energy's Coal Creek Station that combusts lignite in a mine-mouth operation. Since 2009, the 1180-MW plant has employed a new technology to compensate for off-design fuel quality.[7] The DryFining process dried and segregated lignite coal with waste heat energy in a low-temperature system, reducing the moisture content by 10% and removing up to 40% of the sulfur and mercury from the fuel. The flue gas was subsequently reduced by 6%, and the plant efficiency increased by 4%. The investigators recently reported that the average annual improvement in net heat rate for Unit 1 is 3.4% (since 2009) and for Unit 2 the net HRI is 5.8% (Unit 2 also benefitted from a steam turbine upgrade).[8]

2.1.2 Boiler Island

The National Coal Council[9] reported that the unit generating efficiency may be improved by 0.160.33% (lowering heat rate by 50-100 Btu/kWh) if failed boiler surfaces are replaced for a cost of $4-5M in a 500 MW plant. The report also mentions that upgraded economizers might lower the plant heat rate by 0.5-1.0%. The report also mentions that advanced boiler materials (including those using "nano-coatings") were in the experimental stage and could significantly increase the heat transfer because they minimize deposit accumulation.

[6] National Coal Council, *Reliable & Resilient: The Value of Our Existing Coal Fleet*, May 2014. Downloaded from http://www.nationalcoalcouncil.org/NEWS/NCCValueExistingCoalFleet.pdf. The National Coal Council is a Federal Advisory Committee to the U.S. Secretary of Energy.

[7] Great River Energy, *DryFining Fuel Enhancement Process*. Online fact sheet downloaded from http://www.greatriverenergy.com/makingelectricity/newprojects/dryfining_factsheet.pdf on November 25, 2014. Also Bullinger, C.W., M.A. Ness, N. Sarunac, E.K Levy, R.S. Weinstein, and D.R. James, *Method of enhancing the quality of high-moisture materials using system heat sources*, U.S. Patent 8,579,999 B2, November 12, 2013. Downloaded from http://www.google.com/patents/US8579999 on November 25, 2014.

[8] Sarunac, N. M. Ness, and C. Bullinger, "Improve Plant Efficiency and Reduce CO_2 Emissions When Firing High-Moisture Coals." *Power Magazine*, November 1, 2014. Downloaded from http://www.powermag.com/improve-plant-efficiency-and-reduce-co2-emissions-when-firing-high-moisture-coals/?printmode=1 on November 26, 2014.

[9] National Coal Council, *Reliable & Resilient: The Value of Our Existing Coal Fleet*, May 2014. Downloaded from http://www.nationalcoalcouncil.org/NEWS/NCCValueExistingCoalFleet.pdf. The National Coal Council is a Federal Advisory Committee to the U.S. Secretary of Energy.

In 2010 Breeding, Tandra, and Shah[10] presented case studies demonstrating how on-line cleaning systems could be operated automatically in order to optimize the removal of ash and slag deposits in boilers. One sootblowing system includes fifty retractable sootblowers, eight water cannons, and air heater cleaners. A second installation improved overall plant efficiency up to 1%, resulting in a high return on the investment.

Predictive models are used in a U.S. patent for a sootblowing control system in order to determine optimal sequences for sootblower and boiler performance.[11] The optimization algorithm chooses the boiler zone to be treated and the sootblower type that will achieve the best boiler performance based on current operating conditions.

A 2011 white paper by Labbe and Gordon[12] describes four power plant upgrades that contribute to higher efficiencies, lower emissions, greater fuel flexibility, higher availability, lower operating costs, and faster dispatch rates. Three of the four optimizations directly affect boiler operations: control systems, overfire air, and sootblowers. The sootblower optimization mixed a smart logic system that evaluates performance metrics, fouling conditions, and equipment status and programmable sequence blocks that implement the cleaning actions.

The National Coal Council report cites intelligent sootblowers as reducing gross heat rates in older boilers by 30-90 Btu/kWh. In cases where slagging and fouling had reduced efficiency, heat rate reductions were as high as 150 Btu/kWh where lignite or Powder River Basin coals were used, and improvements might be typically made up to 60 Btu/kWh. The cost for an intelligent sootblowing system is cited as $0.5M for a 500-MW plant.

Labbe and Gordon also described overfire air optimization as a process involving new damper drives to regulate secondary air introduction near each burner, coupled with a new distributed control system (DCS) for modulation. The system reduced NO_x emissions by 10% and also decreased the heat rate by improving the balance of oxygen distribution. Labbe and Gordon also described how upgrading the DCS controls on two boiler units resulted in heat rate improvements approaching 1%.

EPRI's Range and Applicability Report (2014) listed several additional measures for the boiler island not found in the S&L Report but did not report potential cost.[13] Those that would not overlap directly with the S&L Report findings include:

1) Automating boiler drains (to route to deaerators instead of condensers at reduced loads)
2) On-site fuel drying (resulting in significant decreases in required air flow)

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[10] Breeding, C., D. Tandra, and S. Shah, "Boiler Cleaning Using ISB (Intelligent Soot Blowing) System Integration: Recent Developments and Case Study," *Proceedings of the American Society of Mechanical Engineers 2010 Power Conference*, Chicago, Illinois, 2010.

[11] James, J.R., J. McDermott, S. Piche, F. Pickard, and N.J. Parikh, *Sootblowing optimization for improved boiler performance*, U.S. Patent 8,498,746 B2, July 30, 2013. Downloaded on November 25, 2014, from http://www.google.com/patents/US8498746.

[12] Labbe, D. and L. Gordon, *Continuous Performance Improvement in Power Generation: Optimization in Action*, Invensys Operations Management, March 2011. Downloaded on November 25, 2014, from http://iom.invensys.com/EN/pdfLibrary/WhitePaper_Invensys_ContinuousPerformanceImprovementInPowerGeneration_03-11.PDF.

[13] Korellis, S., *Range and Applicability of Heat Rate Improvements*, Technical Update, Report Number 3002003457, Electric Power Research Institute, April 2014.

3) Blowdown recovery tank
4) Air heater baskets

2.1.3 Turbine Island

An EPRI technical update report[14] examined how the heat rates changed at a coal-fired power plant when it was reduced from base-load performance to a load-following mode. The three-year study examined a plant that had previously operated at 650 MW (rarely below 400 MW) and later operated with a normal minimum operating load near 150 MW. When the heat rate curve from a near-continuous load-day was compared to that for a transient load-day (four different steady loads), the shape and magnitude matched each other. Another study[15] found that adding one startup-shutdown cycle caused the effective weekly heat rate to rise 0.62% for small subcritical coal-fired boilers, 0.44% for large subcritical coal-fired boilers and for supercritical boilers, and 0.20% in combined cycle plants.

Korellis[16] listed ten different cost-effective upgrades that might be introduced at coal-fired units to improve heat rate during cycling operations:

1) Sliding-pressure operation (2% decrease in heat rate during part load)
2) Variable-speed drives for main cycle and auxiliary equipment
3) Boiler draft system control schemes and operating philosophy
4) Automated pulverizer supervisory controls and variations with mill design
5) Optimum partial-load operation of air quality control systems
6) Feedwater heater drain system modifications for cycling
7) Cooling system optimization
8) Performance monitoring
9) Reducing warm-up flow for idle boiler feed pumps
10) Minimizing flow, pressure, and temperature oscillations during cycling operation

The National Coal Council report shared typical heat rate improvements and capital costs for steam turbine improvements:

1) 10 Btu/kWh for hydrogen purity ($0.25M)
2) 50 Btu/kWh for partial arc admission ($1M)
3) 4 Btu/kWh for control valves
4) 50 Btu/kWh for HP steam seal upgrade ($1M)
5) 95-135 Btu/kWh for HP steam path upgrade ($6M)

[14] Electric Power Research Institute, Product Abstract for *Cycling and Load-Following Effects on Heat Rate*, Product ID 1022061, July 18, 2011. Downloaded on November 25, 2014, from http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001022061.

[15] Kumar, N., P. Besuner, S. Lefton, D. Agan, and D. Hilleman, *Power Plant Cycling Costs*, Report Number NREL/SR-5500-55433, National Renewable Energy Laboratory, April 2012.

[16] Korellis, S., "Coal-Fired Power Plant Heat Rate Improvement Options, Part 1." *Power Magazine*, November 1, 2014. Downloaded on November 26, 2014, from http://www.powermag.com/coal-fired-power-plant-heat-rate-improvement-options-part-1/?printmode=1.

6) 20 Btu/kWh for IP steam seal upgrade ($1M)
7) 50-100 Btu/kWh for IP steam path upgrade ($5M)
8) 120 Btu/kWh for LP steam seal upgrade ($0.75M)
9) 65-225 Btu/kWh for LP steam path upgrade ($5M)

EPRI's Range and Applicability Report (2014) listed several additional measures for the turbine island not found in the S&L Report but did not report potential cost. Those that would not overlap directly with the S&L Report findings include:

1) Running with a single circulation pump under favorable temperatures
2) Condenser ball cleaning system
3) Re-tubing condensers
4) Water box vacuum priming system
5) Circulating water strainers
6) Circulating water turbine
7) Steam seal upgrade
8) Steam path upgrade
9) LP turbine last-stage buckets
10) Exhaust hood steam guide modification
11) Rewind generator
12) Increasing hydrogen purity
13) Partial-arc admission
14) Sliding pressure (a 2% HRI was realized at part load)

2.1.4 Other Improvements

Labbe and Gordon[17] described how a cooling tower advisory system was integrated into the NO_x and heat rate optimization system at a plant in such a manner that the pumps and fans would optimize the net electricity generation. An hourly savings of 1205 kW was reported for a single month.

EPRI's Range and Applicability Report (2014) listed several additional measures outside the boiler and turbine islands not found in the S&L Report but did not report potential cost. Those that would not overlap directly with the S&L Report findings include:

1) Replacement of first point heater (150 Btu/kWh)
2) Supplemental cooling towers
3) Deep lake water intake
4) Power supply upgrade for air pollution control equipment

[17] Labbe, D., and L. Gordon, *Continuous Performance Improvement in Power Generation: Optimization in Action*, Invensys Operations Management, March 2011. Downloaded on November 25, 2014, from: http://iom.invensys.com/EN/pdfLibrary/WhitePaper_Invensys_ContinuousPerformanceImprovementInPowerGeneration_03-11.PDF.

5) Upgrade air compressors
6) Plant lighting upgrade

The National Coal Council report[18] also cites some additional heat rate improvements:

1) Up to 150 Btu/kWh for advanced process instrumentation and controls ($0.5-0.75M)
2) Low temperature heat recovery (air heater performance, feedwater preheating, and supplemental low temperature gas-side heat recovery)
3) 15-150 Btu/kWh for variable frequency drives ($9-11M for a 500-MW plant)
4) Up to 70 Btu/kWh in summers for replacing or augmenting the cooling tower pack ($1.5-5M for a 500-MW plant)
5) 600-1200 Btu/kWh through a topping cycle addition (could be developed within 10 years)
6) 300 Btu/kWh through a bottoming cycle with an organic solvent would supplant use of water for cooling (currently only used in small industrial processes)

Some common recommendations among the five plants in EPRI's Range and Applicability Report also held potential for HRIs. These included:

1) Heat Rate Awareness training for operations staff (50 to 100 Btu/kWh)
2) Making heat rate information readily available to more plant personnel (50 to 150 Btu/kWh)
3) Improving utilization of Controllable Losses information by operations staff (75 to 100 Btu/kWh)
4) Initiating routine testing programs (75 to 200 Btu/kWh)

Hansel[19] wrote that most plants already have the most advanced water treatment systems, so no opportunities were available there for HRIs.

2.2 Total HRI Studies

In contrast to studies that examined individual measures, some studies also compared overall plant heat rates and efficiencies. Selected information from a 2010 NETL report[20] compares the average fleet efficiencies for different boiler segments against the 90th percentiles based on a weighting by generation (Table 2-3). Those differences (ranging from 1.8 to 4.2%) might represent a present-day level of possible HRIs that moves existing boilers toward higher performance levels.

[18] National Coal Council, *Reliable & Resilient: The Value of Our Existing Coal Fleet*, May 2014. Downloaded from http://www.nationalcoalcouncil.org/NEWS/NCCValueExistingCoalFleet.pdf. The National Coal Council is a Federal Advisory Committee to the U.S. Secretary of Energy.

[19] Hansel, Peter, *Heat Rate Reductions and Carbon Emissions: A Policy Mechanism for Regulating Coal Plants under 111(d) of the Clean Air Act*, April 22, 2014. Downloaded from http://dukespace.lib.duke.edu/dspace/bitstream/handle/10161/8508/Heat%20Rate%20Reductions%20and%20Carbon%20Emissions%20-%20Peter%20Hansel%20MP%20Final.pdf?sequence=1 on November 25, 2014.

[20] DiPietro, P. and K. Krulla, *Improving the Efficiency of Coal-Fired Power Plants for Near Term Greenhouse Gas Emissions Reductions*, DOE/NETL-2010/1411, National Energy Technology Laboratory, 2010. Downloaded on December 1, 2014, from http://netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/DOE-NETL-2010-1411-ImpEfficCFPPGHGRdctns-0410.pdf.

Table 2-3. 2010 NETL Assessment of Coal-Fired Power Plant Efficiencies

Segment Criteria			Sub-population Characteristics			Efficiency		
Unit Type	Coal Type	Size (MW)	Capacity (GW)	# Units	Generation (BkWh)	Average	90th Percentile	Difference
Low Pressure Subcritical (600-1600 psig)	Bit	0-200	10.3	127	44	29.6%	33.0%	3.4%
	Sub-bit		4.6	59	26	27.5%	29.8%	2.3%
	Other		0.6	7	2	27.4%	30.5%	3.1%
High Pressure Subcritical (1800-2600 psig)	Bit	0-200	21.6	134	112	32.1%	34.8%	2.7%
		200-500	33.4	103	189	32.8%	35.6%	2.8%
		500+	29.7	48	176	32.7%	35.0%	2.3%
	Sub-bit	0-200	7.2	47	42	30.7%	32.5%	1.8%
		200-500	31.2	97	191	31.4%	35.6%	4.2%
		500+	64.4	98	401	31.6%	33.8%	2.2%
	Other		11.1	28	72	31.7%	35.1%	3.4%
Supercritical (3334+ psig)	Bit		60.7	79	372	35.1%	37.3%	2.2%
	Sub-bit		15.0	20	90	35.2%	37.2%	2.0%
	Other		8.1	13	55	31.8%	34.9%	3.1%

2.3 Associated Costs

Although most NETL publications since 2009 deal with newer technologies that affect plant-wide heat rates (e.g., gasification and carbon capture), one subcontract report from NETL lists some costing estimates.[21] Cases 9 and 11 list a breakdown of many costs associated with subcritical and supercritical coal-fired plants without carbon capture.

[21] National Energy Technology Laboratory, *Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity*, DOE/NETL-2010/1397, last updated in 2013. Downloaded on November 17, 2014 from http://www.netl.doe.gov/File%20Library/Research/Energy%20Analysis/OE/BitBase_FinRep_Rev2a-3_20130919_1.pdf.

3 Statistical Assessment of Heat Rates in the Plant Database

The EIA-860 and EIA-923 surveys reveal a great deal about plant operations, as well as some specific information about generators and boilers. These surveys may also be supplemented by annual information collected by the U.S. Environmental Protection Agency (EPA). EIA uses the net generation data (gross generation minus parasitic load) and heat input information for fossil-fuel boilers to compute net annual heat rates for each generator over a five-year period. For the coal-fired units, the 2012 heat rates varied from 8759 to 25,000 Btu/kWh at 1027 generators for which a single boiler could be matched.[22]

This chapter describes an analysis of the heat rates for coal-fired boilers as part of an effort to understand how the EIA data might be used to identify units that could implement improvements in future years. This work may support EIA modeling efforts that aim to choose between installing unit improvements and retiring existing units. Other chapters consider the costs, but this chapter focuses on projecting the deviation of existing heat rates from heat rates at units of similar design.

3.1 Data Processing

The basis for this work is the AEO2014 Plant File Inputs (AEO2014 plant listing inputs.xls) that share data records from plants online in 2012 (15,993 records). Of these data, 1084 records applied to the coal-fired EFD plant types (CAV, CSC, and CSU)[23], and each record is associated with a particular generator. According to *Assumptions and Updates to the AEO 2014 Plant File*, the heat rates represent the net generation divided by the heat input to the associated boiler (over a five-year period). EIA uses a heat rate ceiling of 25,000 Btu/kWh in its calculations.

An EIA-860 file (EnviroAssocY2012.xlsx) provides crosswalks to match the generator IDs to individual boiler IDs. The file also provides crosswalks to tie boiler IDs to the cooling system IDs, FGD system IDs, and FGP collection system IDs.

The data were provided from multiple sources and matched based on plant and boiler ID codes:

- EIA-923 schedules (2012 data)
- EIA-860 surveys
- EPA eGRID 9th edition (2010 data)
- EPA Clean Air Markets Database (2012 data from ampd.epa.gov/ampd/)

Data were generally provided as plant level, boiler level, or generator level records, but some information was listed in multiple records for the plants (e.g., monthly mine fuel receipts). The composite database held more than 200 fields, but many of the parameters were not expected to correlate at all with heat rates (e.g., cooling water outlet distance from the shore) and were excluded from further consideration.

3.2 General Data Population Characteristics

Table 3-1 describes the numeric variables that were included in the study.

[22] As per EIA direction, 57 combined heat and power units were excluded from the analysis.

[23] These plant types represent three existing coal-fired technologies: CAV = New Advanced Coal; CSC = Coal Steam with Scrubber; and CSU = Coal Steam post-1965.

Table 3-1. Distribution of Numeric Parameters Associated with Coal-Fired Generators

Variable	Number of data points	Percentage of missing points	Average	Standard Deviation	Minimum	25th percentile	50th percentile	75th percentile	Maximum
Heatrate (Btu/kWh)	1027	0%	11,300	2,400	8,759	10,247	10,644	11,287	25,000
CAMD2012 heatrate (Btu/kWh)	858	16%	10,200	1,100	7,311	9,473	10,008	10,660	18,474
Summer Capacity (MW as listed in EPA CAMD2012)	1027	0%	294	250	1	100	200	476	1,300
Online Year	1027	0%	1970	14	1944	1958	1969	1979	2012
Variable O&M ($/MWh)	1027	0%	2.60	1.50	0.58	1.46	2.23	3.33	11
Annual Fixed O&M ($/KW)	1027	0%	47	18	7	33	44	60	98
Annual Capital Additions ($/KW)	1027	0%	18	31	0	4	11	21	330
Heat Input (MMBtu)	869	15%	19,000,000	18,000,000	1,251	4,525,293	12,519,851	32,227,304	95,309,144
Gross Load (MWh)	860	16%	2,000,000	1,900,000	0	444,604	1,229,583	3,357,001	10,039,827
Nameplate Capacity (MW)	1027	0%	350	290	4	114	253	578	1,426
Generator Summer Capacity (MW)	1027	0%	330	270	0	103	232	531	1,300
Generator Winter Capacity (MW)	1027	0%	330	270	0	103	235	543	1,300
Planned Retirement Year	203	80%	2015	2	2012	2014	2015	2015	2021
FGD In-service Year	491	52%	1999	13	1971	1985	2007	2010	2019
Pond Landfill Requirements (Acre-Foot per Year)	339	67%	160	270	0	19	77	200	2,714
Specs of Coal Ash	463	55%	12%	5%	0%	10%	10%	10%	40%
Specs of Coal Sulfur	463	55%	0%	1%	0%	0%	0%	0%	10%
FGD Trains Total	467	55%	2	2	1	1	1	3	12
FGD Trains 100%	454	56%	2	1	1	1	1	3	10
FGD Sulfur Removal Efficiency	475	54%	93%	10%	50%	90%	100%	100%	100%
Sulfur Emission Rate (lbs per hr)	473	54%	1500	1800	0	352	743	1,858	9,999
FGD Cost Structure ($K)	410	60%	130,000	200,000	21	27,982	62,224	177,084	1,445,626
FGD Disposal Cost ($K)	276	73%	14,000	26,000	1	1,776	5,663	14,475	223,438
FGD Other Cost ($K)	196	81%	45,000	152,000	10	470	13,700	34,500	1,938,000
FGD Cost Total ($)	460	55%	159,000	203,000	21	37,738	92,481	236,861	1,503,972
Quantity of FGD Sorbent	390	62%	64	68	0	13	39	98	353

Variable	Number of data points	Percentage of missing points	Average	Standard Deviation	Minimum	25th percentile	50th percentile	75th percentile	Maximum
FGD Electrical Consumption	389	62%	56,000	64,000	0	12,667	37,120	70,680	408,706
FGD Efficiency at Annual Operating Factor	409	60%	90	13	0	89	95	97	100
FGD Efficiency at 100%	337	67%	92	11	0	90	95	98	100
FGD Chem Cost	368	64%	2,400	3,600	0	448	1,303	2,842	27,633
FGD Labor Cost	368	64%	1,100	1,400	0	261	652	1,298	10,370
FGD Waste Cost	344	67%	680	1,100	0	23	289	786	8,327
FGD Maintenance Material Other	362	65%	1,200	1,600	0	350	751	1,594	17,880
Total O and M	375	63%	5,200	5,700	0	1,748	3,760	6,835	36,644
No FGD Control	73	93%	0	0	0	0	0	0	1
FGP Inservice Year	883	14%	1981	11	1949	1975	1979	1985	2012
FGP Installed Cost ($K)	873	15%	16.000	26,000	1	2,630	8,390	19,900	267,000
FGP Collection Efficiency	883	14%	99%	1%	80%	99%	100%	100%	100%
Emission Rate (lbs per hr)	883	14%	190	230	0	45	108	250	2,120
FGP Hours In Service	864	16%	5,700	2,600	0	3,998	6,793	7,757	8,760
Cooling System In-service Year	848	17%	1970	14	1924	1958	1970	1979	2012
Intake Rate at 100% (Cubic Feet per Second)	844	18%	450	670	1	27	212	535	4,711
Number of Federal Air Pollution Programs[24]	886	14%	6	2	1	5	6	7	8

[24] This variable is a straight count of the number of programs identified by the nominal parameter programs listed in Table 3-3.

Some additional numeric fields describing cooling systems were not included in the computations in order to reduce the analysis burden: Chlorine Inservice Year, Pond Inservice Year, Pond Volume (Acre Feet), Tower Inservice Year, Tower Water Rate (Cubic Feet per Second), Cooling System Power Requirement (MW), Cost Ponds (Thousand Dollars), Cost Towers (Thousand Dollars), and Cost Chlorine Equipment (Thousand Dollars).

The correlations among the numeric values were compared, and those with correlation coefficients greater than 0.6 are presented in Table 3-2. Table 3-2 clearly points to redundancies when the heat inputs, gross loads, and capacities are used.

Table 3-2. Numeric Parameter Pairs with Correlation Coefficients with Absolute Values Greater than 0.60

Parameter 1	Parameter 2	Correlation Coefficient
Heat Rate (Btu/kWh)	Variable O&M ($/MWh)	0.63
Summer Capacity (MW from the EPA CAMD2012 database)	Variable O&M ($/MWh)	-0.61
	Heat Input (MMBtu)	0.77
	Gross Load (MWh)	0.77
	Nameplate Capacity (MW)	0.89
	Generator Summer Capacity (MW)	0.90
	Generator Winter Capacity (MW)	0.90
Online Year	Heat Input (MMBtu)	0.62
	Gross Load (MWh)	0.61
	Cooling System Inservice Year	0.95
Variable O&M ($/MWh)	Annual Fixed O&M ($/kW)	0.67
	Heat Input (MMBtu)	-0.66
	Gross Load (MWh)	-0.66
	Nameplate Capacity (MW)	-0.68
	Generator Summer Capacity (MW)	-0.67
	Generator Winter Capacity (MW)	-0.67
Heat Input (MMBtu)	Gross Load (MWh) Nameplate Capacity (MW) Generator Summer Capacity (MW) Generator Winter Capacity (MW)	1.00 0.89 0.90 0.90
Gross Load (MWh)	Nameplate Capacity (MW)	0.90
	Generator Summer Capacity (MW)	0.90
	Generator Winter Capacity (MW)	0.90
Nameplate Capacity (MW)	Generator Summer Capacity (MW)	1.00
	Generator Winter Capacity (MW)	1.00
Generator Summer Capacity (MW)	Generator Winter Capacity (MW)	1.00
Planned Retirement Year	FGD Cost Structure ($K)	-0.66
	FGD Disposal Cost ($K)	-0.64
FGD Trains Total	FGD Trains at 100%	0.97
FGD Cost Structure ($K)	FGD Cost Total ($)	0.96
FGD Efficiency at Annual Operating Factor	FGD Efficiency at 100%	0.68
FGD Chemical Cost	FGD Total O&M	0.87
FGD Waste Cost	FGD Total O&M	0.61
FGD Maintenance Material Other	FGD Total O&M	0.63

In addition to the numeric parameters, Table 3-3 lists the nominal and logical parameters that were considered as generator/boiler/plant characteristics that might affect heat rate. Table 3-3 also shows some consolidated variables that were evaluated in cases where entries could be grouped.

Table 3-3. Nominal and Logical Characteristics Considered in this Study

Variable	Number of Blanks	Populated Entries
NEMS EFD Plant Type	0	CAV, CSC, CSU
NEMS ECP Plant Type[25]	0	B1, B3, B5, B7, C1, C4, C7, CX, H1, H4, H7, IG
Programs	141	Combination of the entries CAIRNOX, CAIROS, CAIRSO2, RGGI, TRNOX, TRNOXOS, TRSO2G1, and ARP
Fuel Type (Primary)	141	Coal, Coal, Pipeline Natural Gas
Operating Status	141	Operating, Operating (Started 01/24/2012)
NOx Control Status	66	CN, CO, NA, OP, OS, OZ, RE, SB, SC, TS
Low NOx Process 1	66	AA, CF, FU, H20, LA, LN, NA, OT, OV, SN, SR
Low NOx Process 2	390	AA, BF, CF, FU, LA, LN, OT, OV, SN, SR
Low NOx Process 3	785	AA, FU, LA, LN, NH3, OT, OV, SN, SR
Mercury Emission Control	66	Y, N
Prime Mover	0	CA, CT, ST
GenStatus	0	OA, OP, OS, RE, SB
Multiple Fuels	0	Y, N
Turbines	1,016	1
Cogenerator	0	Y, N
Sector Name	0	Electric Utility, IPP Non-CHP
Topping or Bottoming	991	B, T
Duct Burners	304	N
Planned Modifications	33	Y, N
Planned Uprate Year	1,019	2013, 2014, 2016, 2017
Planned Derates Year	1,014	2013, 2014, 2015, 2016, 2017
Planned New Prime Mover	1,026	ST
Planned Repower Year	1,018	2013, 2014, 2015, 2016, 2017
Other Modifications Year	1,004	2013, 2014, 2015, 2018
Solid Fuel Gasification System	89	Y, N
Pulverized Coal Technology	112	Y, N
Fluidized Bed Technology	974	Y, N
Subcritical Technology	348	Y, N
Supercritical Technology	876	Y, N
Ultrasupercritical Technology	1,023	Y, N
Carbon Capture Technology	1,024	Y, N
FGD Status	536	CN, CO, OP, OS, PL, RE, SB, SC
FGD Type 1	541	BR, CD, DP, OT, PA, SD, SP, TR, VE
FGD Type 2	986	PA, SP, TR, VE
FGD Type 3	1,026	VE
FGD Type 4	1,027	none
Sorbent Type 1	554	AF, DB, DL, LA, LF, LI, LS, OT, SA, SB, SC, SL
Sorbent Type 2	987	DB, DL, LI, MO, SC, SF
Sorbent Type 3	1,026	DB

[25] ECP types defined on page vii.

Variable	Number of Blanks	Populated Entries
Sorbent Type 4	1,027	none
FGDByproductRecovery	554	Y, N
Sludge Pond Lined	555	Y, N, NA
Flue Gas Bypass FGD	554	Y, N
FGP Status	144	OP, OS, SB, SC
FGPCollectorType1	144	BP, BR, BS, EC, EH, EK, EW, MC, OT, WS
FGPCollectorType2	889	BP, BR, EC, EK, EW, MC, OT, WS
FGPCollectorType3	1,011	EK, MC, SC, WS
No FGP Control	972	., 0, 1
Cooling Status	179	OP, OS, SC
Cooling Type 1	179	DC, HRF, OC, ON, OT, RC, RF, RI, RN
Cooling Type 2	972	HT, OC, ON, OT, RC, RF, RI, RN
Cooling Type 3	1,022	RI
Cooling Type 4	1,027	none
Tower Type 1	658	MD, MW, NW, WD
Percent Dry Cooling	998	0%, 100%
Unit Type	141	Bubbling fluidized bed boiler, Cell burner boiler, Circulating fluidized bed boiler, Cyclone boiler, Dry bottom turbo-fired boiler, Dry bottom vertically-fired boiler, Dry bottom wall-fired boiler, Dry bottom wall-fired boiler (Started Jan 24, 2012), Tangentially-fired, Wet bottom turbo-fired boiler, Wet bottom wall-fired boiler
Firing Type	136	CELL, CYCLONE, DRY FRONT/WALL, DRY OPPOS/WALL, DRY STOKER, DRY TANGENTIAL, DRY TURBO, DRY VERTICAL, DRY WALL, FLUIDIZED, TANGENTIAL, WET TURBO, WET WALL
Fuel Type	103	BIT, LIG, SUB, WC
Firing Class (consolidation of Firing Type variable)	136	Bottom-fired, Dry Wall-fired, Tangential-fired, Wet-bottom
Low NOx Summary 1 and Low NOx Summary2 (consolidation of Low NOx Process variables)	66 390	Combustor, Injection, Recirculation, Reduction, Other
FGP Collector Summary1 (consolidation of FGPCollectorType1)	144	Baghouse, Cyclone, ESP, WetScrubber, Other

3.3 Influence of Nameplate Capacity on Heat Rate

Leidos conducted a preliminary investigation of plotted heat rates versus some of the parameters listed in Table 3-1 and Table 3-3; the selected parameters were chosen primarily with regard to the distributions found in the data set and the fractions of missing data. Relationships were easier to identify and more linear when the variables were compared to the inverse heat rate, a measure of unit efficiency. However, the influences of most individual variables still appeared small against the inverse heat rates that varied from 40 to 114 kWh/MMBtu.

Therefore, the preliminary investigation included application of the M5P algorithm[26] to develop a piecewise linear regression model. A piecewise approach would allow subsets of the inverse heat rates to be evaluated separately against the various parameters, and the algorithm would identify those parameters with the most influence on the inverse heat rates. Using a leave-one-out approach for evaluating the model performance, the Weka Explorer software executed the M5P algorithm to predict inverse heat rate with a correlation coefficient of 0.83 and a relative absolute error of just 54%. Roughly thirty parameters were used in the four piecewise linear models that were divided as shown in Figure 3-1. The numbers in parentheses represent the number of records followed by the relative absolute errors for the data subset. Those in the largest group (627 records) had nameplate capacities greater than 181 MW and a relative absolute error of only 32%; the predictive ability was much lower for those with nameplate capacities less than 106 MW.

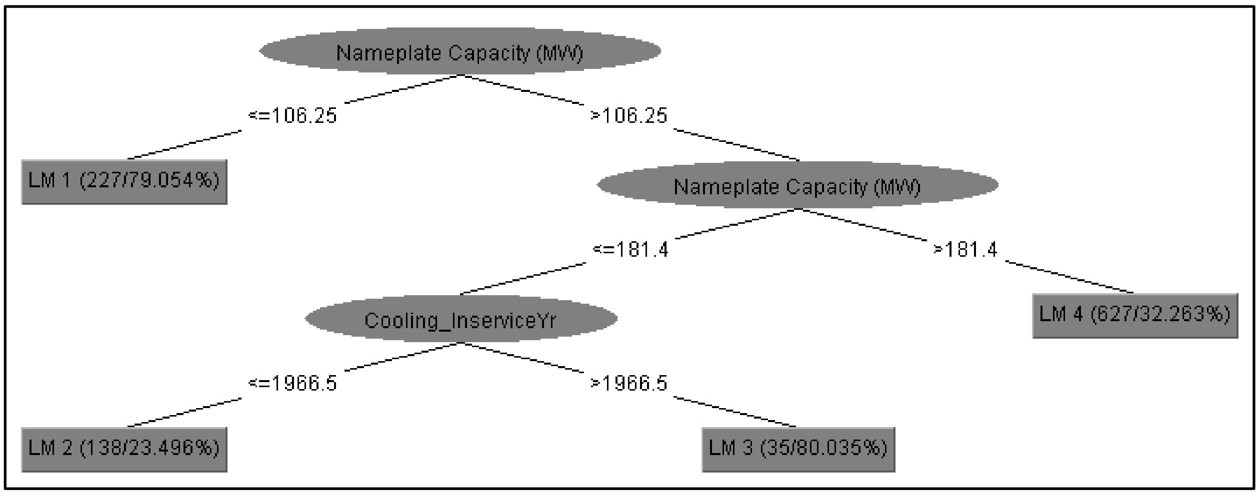

Figure 3-1. Preliminary Decision Tree for Describing Inverse Heat Rates of Coal-Fired Generators

The decision tree suggested that different linear dependences would be evident if the predicted inverse heat rates were plotted relative to the nameplate capacity (Figure 3-2). Figure 3-2 illustrates that the inverse heat rates were highly dependent on nameplate capacity at low nameplate capacities and less so as the nameplate capacity increased.[27] Figure 3-2 also illustrates the best linear fits for the data.

More efficient plants are found for the generators with higher nameplate capacities, but this finding is not very useful for studies into finding ways to increase plant efficiencies. A transformation to mask the dependence of inverse heat rates on nameplate capacity might reveal the influences of various equipment types on the plant efficiencies.

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[26] The M5P (or M5') algorithm represents a 1997 improvement of Quinlan's original M5 algorithm (1992). It builds piecewise linear regression models of numeric data, but may use nominal, ordinal, and logical parameters within the model tree and within the regression equations.

[27] Such behavior may have indicated a logarithmic dependence on nameplate capacity, but logarithmic evaluations did not fit the data well.

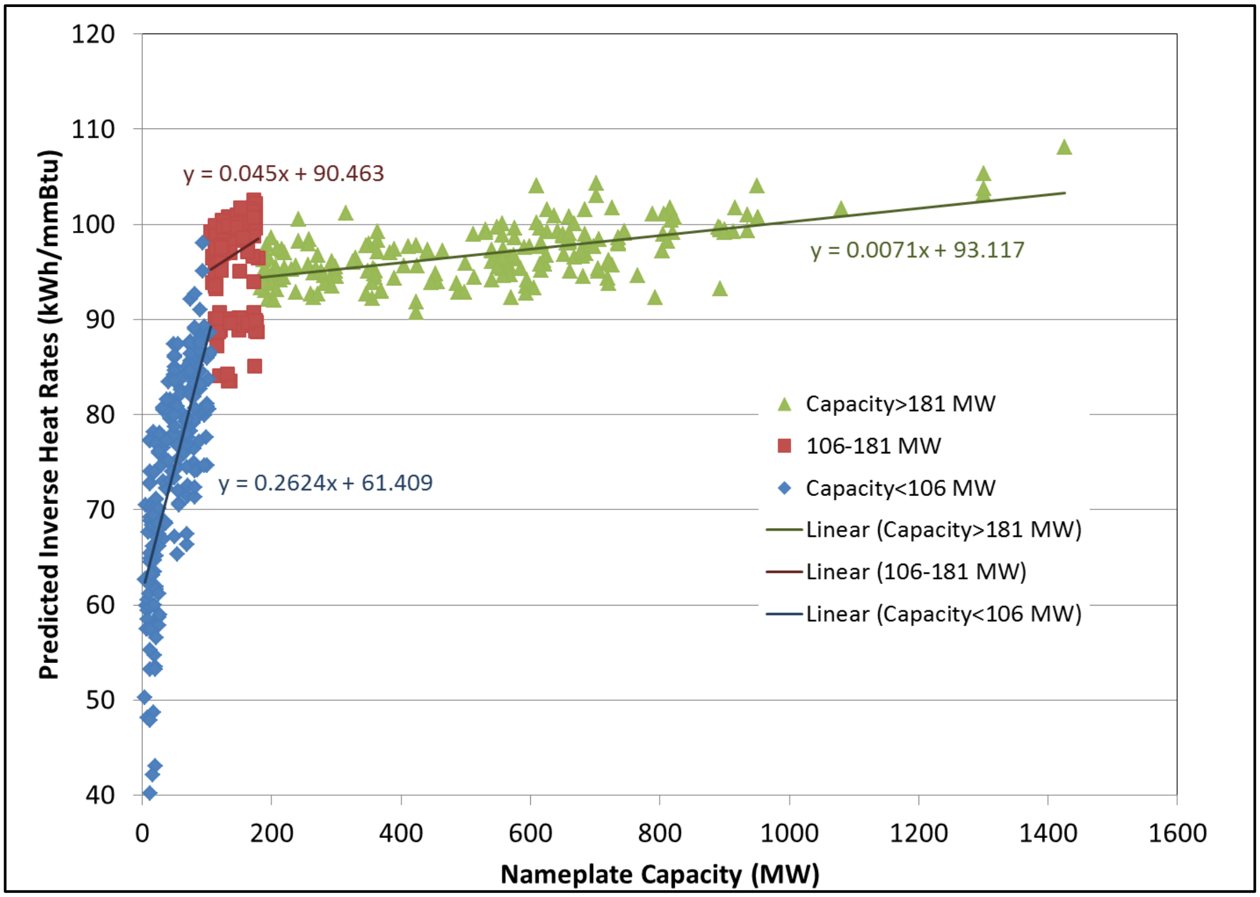

Figure 3-2. Preliminary Relationship between Nameplate Capacity and Predicted Inverse Heat Rates

3.4 Slope Function Analysis

The three linear fits shown in Figure 3-2 suggest that the inverse heat rate data may be transformed to a variable referred to as the dimensionless slope function:

$$\text{Slope function} = \begin{cases} \dfrac{\text{inverse heat rate}}{0.262 \times \text{NPC} + 61.4} & \text{where NPC} \leq 106\text{ MW} \\ \dfrac{\text{inverse heat rate}}{0.045 \times \text{NPC} + 90.5} & \text{where NPC} \geq 106\text{ MW} \quad \text{and NPC} < 181\text{ MW} \\ \dfrac{\text{inverse heat rate}}{0.0071 \times \text{NPC} + 93.1} & \text{where NPC} > 181\text{ MW} \end{cases}$$

Where, NPC represents the nameplate capacity. The numerators are surrogates for actual efficiencies, and the denominators represent the average efficiency for generators of similar sizes. The Slope Function is a dimensionless parameter. Records with slope functions greater than one represent generators that perform better than units of similar size, and those with slope functions less than one underperform. Figure 3-3 illustrates the distribution of the Slope Function parameter.

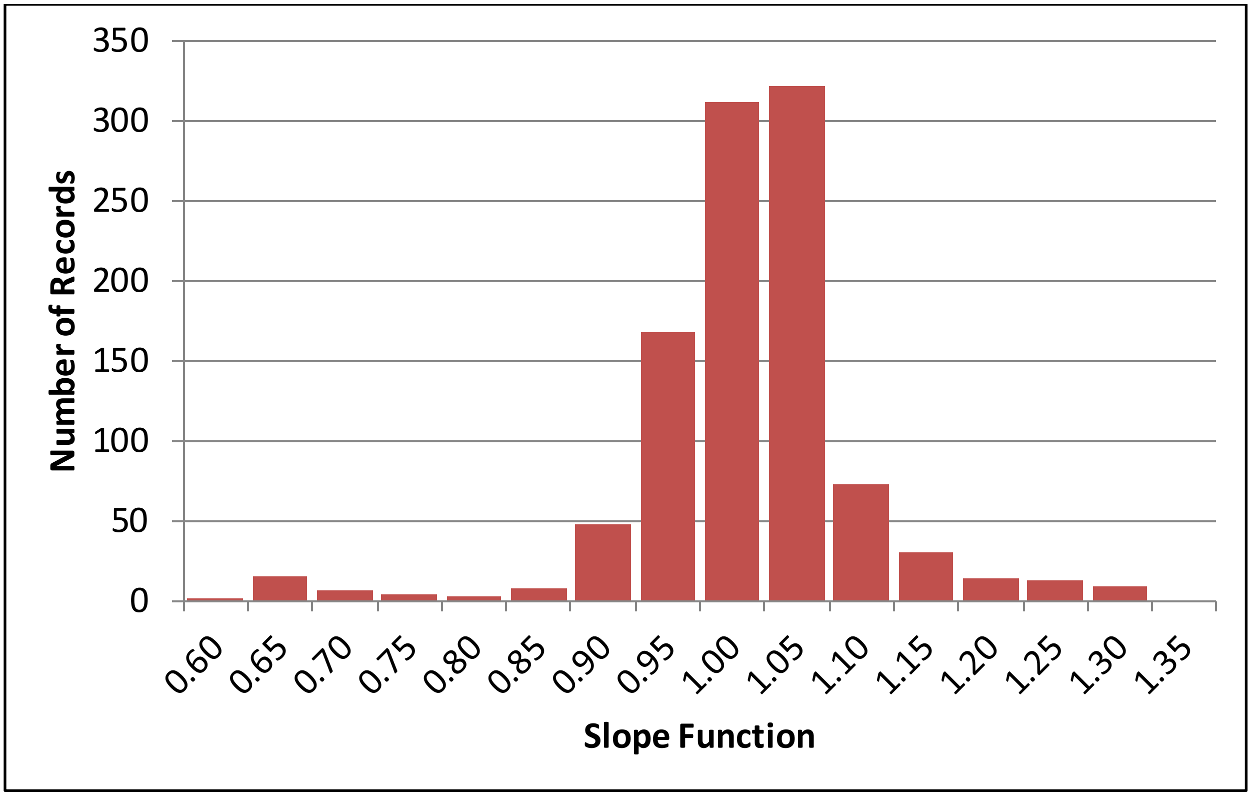

Figure 3-3. Histogram Showing the Distribution for the Slope Function Transformation

The M5P algorithm could generate models for Slope Function that had correlation coefficients as high as 0.5, but no single parameter strongly influenced the Slope Function parameter. Some further data cleaning was deemed necessary to be sure that variables were being treated properly.

An attribute evaluation determines the parameters that the target parameter is most heavily dependent on but are independent of one another. Four runs were made using the Weka *AttributeEvaluator* on the preliminary data sets to determine which variables most influence the Slope Function variable and are independent of other variables. The CfsSubsetEval algorithm selectively chooses the parameter sets that are highly correlated with the various classifications but have low intercorrelation, but the Wrapper[M5Rules] algorithm also uses cross validation to estimate the accuracy of the M5Rules algorithm with each subset of parameters.[28] The results yielded the following list of variables with at least an occurrence in one run (Table 3-4):

[28] The CfsSubsetEval and Wrapper[M5Rules] evaluators were paired with two different methods to search for a good subset of the data attributes: *BestFirst* and *GreedyStepwise*. The *BestFirst* method allows backtracking in the search when the subsetting stops improving, but the *GreedyStepwise* method stops the search when inclusion of the next attribute would decrease the evaluation matrix.

Table 3-4. Results from the *AttributeEvaluator* Showing Those Variables That Most Influence the Slope Function Variable and Are Independent of Other Variables

Parameter	CfSSubsetEval	Wrapper[M5Rules]
NEMS EFD Plant Type	•	•
Primary fuel classification (Bituminous, sub-bituminous, lignite, or waste coal)		•
Annual Capital Additions ($/kW)		•
Variable O&M ($/MWh)	•	
Nameplate Capacity (MW)		•
Low NO_x Process 2	•	
Mercury Emission Control (Y or N)	•	•
Generator status (operating, out of service, retired, etc.)	•	
Planned Retirement Year (2012 through 2021)	•	•
Solid Fuel Gasification System (Y or N)	•	
Subcritical Technology (Y or N)	•	
FGD Type 1	•	
FGP Status	•	
FGPCollectorType1	•	
Cooling Status	•	
Number of Federal Air Pollution Programs (0 to 8 and may act as a geographic surrogate)	•	

Some of these parameters that were deemed significant by the *AttributeEvaluator* did not seem to have enough records to be considered influential in the model development. For example, the Planned Retirement Year parameter is missing in 80% of the records, but the model had been replacing that missing data by the mode value of 2015. Therefore, the missing data were recoded for Planned Retirement Year to reflect a condition that no retirement date was yet planned.

The *AttributeEvaluator* was again run to determine the dependences of Slope Function on the revised variables with three trials (BestFirst+CfsSubsetEval, GreedyStepwise+CfsSubsetEval, and GreedyStepwise+ Wrapper[M5Rules]); the fourth case did not converge. The results yielded the following list with at least an occurrence in one run:

- NEMS EFD Plant Type
- Primary fuel classification (Bituminous, sub-bituminous, lignite, or waste coal)
- Annual Capital Additions ($/KW)
- Variable O&M ($/MWh)
- Nameplate Capacity (MW)
- Low NOx Process Summary 2
- Mercury Emission Control (Y or N)
- Generator status (operating, out of service, retired, etc.)
- Solid Fuel Gasification System (Y or N)
- Pulverized Coal Technology (Y or N)
- Subcritical Technology (Y or N)

- FGD Status
- FGD Type 1
- FGP Status
- FGPCollectorType Summary 1
- Cooling Status
- Number of Federal Air Pollution Programs (0 to 8 and may act as a geographic surrogate)

Using only these variables, a "*leave-one-out-approach*" was again used with the M5P algorithm to predict Slope Function, and the minimum number of records for a decision tree leaf was varied from 4 to 40. The error summaries were similar with correlation coefficients ranging from 0.50 to 0.53.

However, there was still a question about reported data that may be influenced by neighboring equipment. For example, two generators at the PPL Montour plant use Boiler 1 with nameplate capacities of 17.2 and 805.5 MW. The Slope Function value for the smaller generator is 1.6 (not shown in Figure 3-3) because it operates 60% more effectively than similarly sized generators. All data with slope functions more than 3 standard deviations from the average (less than 0.70 or greater than 1.26) were filtered and the model rerun. The data fits did not improve, illustrating that removal of outliers did not improve the model performance.

In the Attribute Selector, the one scheme that operated with the M5P subsetting approach (GreedyStepwise+ Wrapper[M5Rules]) had yielded the following selection of variables to describe the Slope Function:

- NEMS EFD Plant Type
- Primary fuel classification (Bituminous, sub-bituminous, lignite, or waste coal)
- Nameplate Capacity (MW)
- Pulverized Coal Technology (Y or N)
- Subcritical Technology (Y or N)
- FGD Status (Cancelled, New under construction, Operating, Out of service, Planned, Retired, Standby, or Cold Standby)
- FGPCollectorType Summary 1 (Baghouse, Cyclone, ESP, WetScrubber, or Other)

These seven variables were used with the M5P classifier algorithm to yield a seven-rule model that is dependent on this smaller number of parameters and yields a correlation coefficient of 0.49. This is only a mild improvement to the model that had been based only on nameplate capacity, but the model points to physical plant data that might influence heat rates.

Figure 3-4 illustrates the decision tree and the seven linear regression models that can be used to fit the Slope Function. For example, the two rules in the lower left of the figure show that the slope function increases by 0.07 or 0.09 if bituminous fuel is used (instead of lignite). The full models included additional parameters, but only those shown in the figure altered the tenths or hundredths place on the calculated Slope Function.

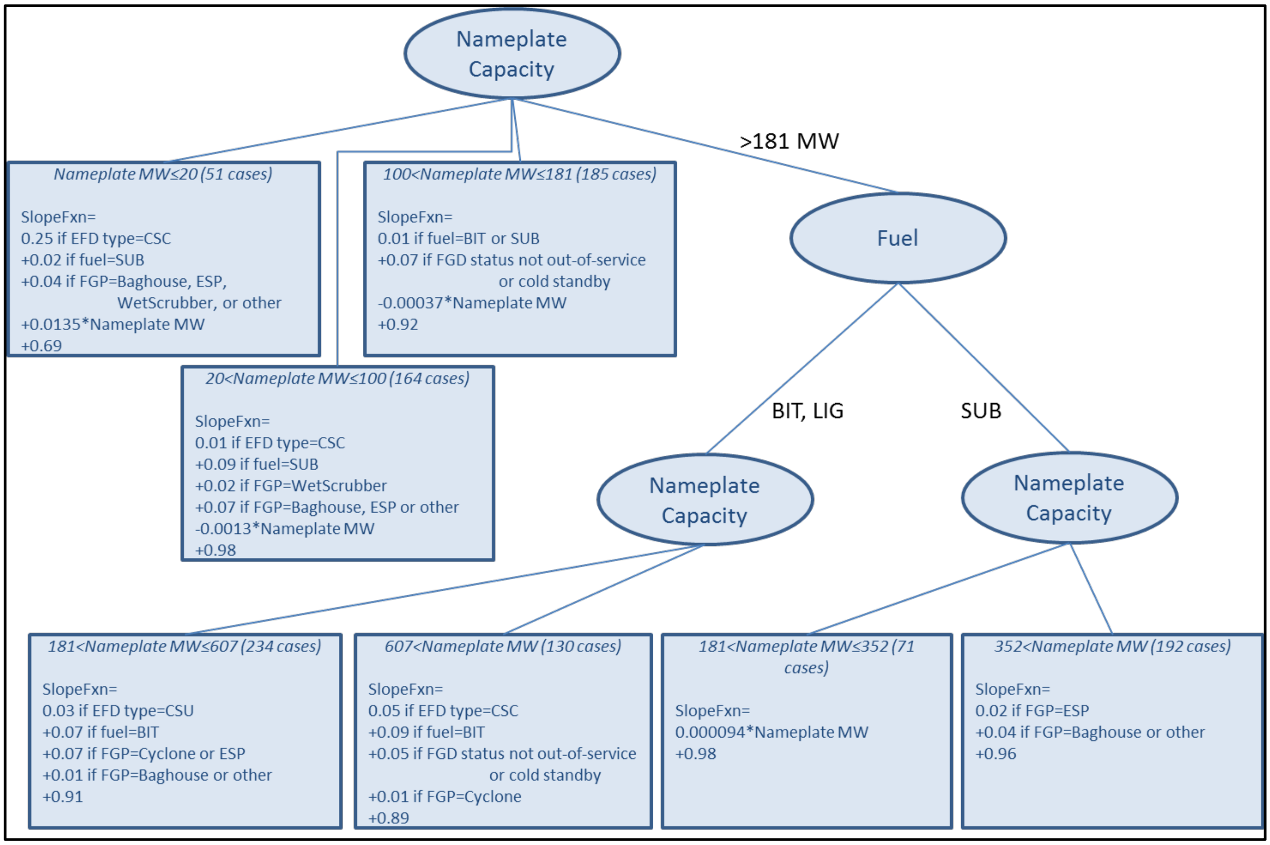

Figure 3-4. Decision Tree to Describe the Slope Function Using the M5P Piecewise Linear Regression Model

3.5 Model Predictions of Heat Rate

In the previous sections, the Slope Function was defined as a ratio of the inverse heat rate (kWh/mmBtu) to a linear function of the nameplate capacity. Therefore, the predicted heat rates may be computed by the expression:

$$\text{Heat rate}\left(\frac{\text{Btu}}{\text{kWh}}\right)=\begin{cases}\dfrac{10^6}{(0.262\times \text{NPC}+61.4)(\text{Slope function})} & \text{where NPC}\le 106\text{ MW}\\[2ex] \dfrac{10^6}{(0.045\times \text{NPC}+90.5)(\text{Slope function})} & \text{where NPC}\ge 106\text{ MW and NPC}<181\text{ MW}\\[2ex] \dfrac{10^6}{(0.0071\times \text{NPC}+93.1)(\text{Slope function})} & \text{where NPC}>181\text{ MW}\end{cases}$$

Where, the Slope Function is found in Figure 3-4 on each of the seven leaves of the decision tree. To ensure that the spectrum of data points is still easily visible, Figure 3-5 presents the inverse of the reported heat rates versus the predicted data points. The best linear fit has an r^2 correlation coefficient of 0.624 with a slope of 0.987, and the red dashed lines show slopes corresponding to a 50% confidence interval. Generators to the left of the lines have lower efficiencies than similar units and represent the generators with the greatest likelihood that the operations can be improved.

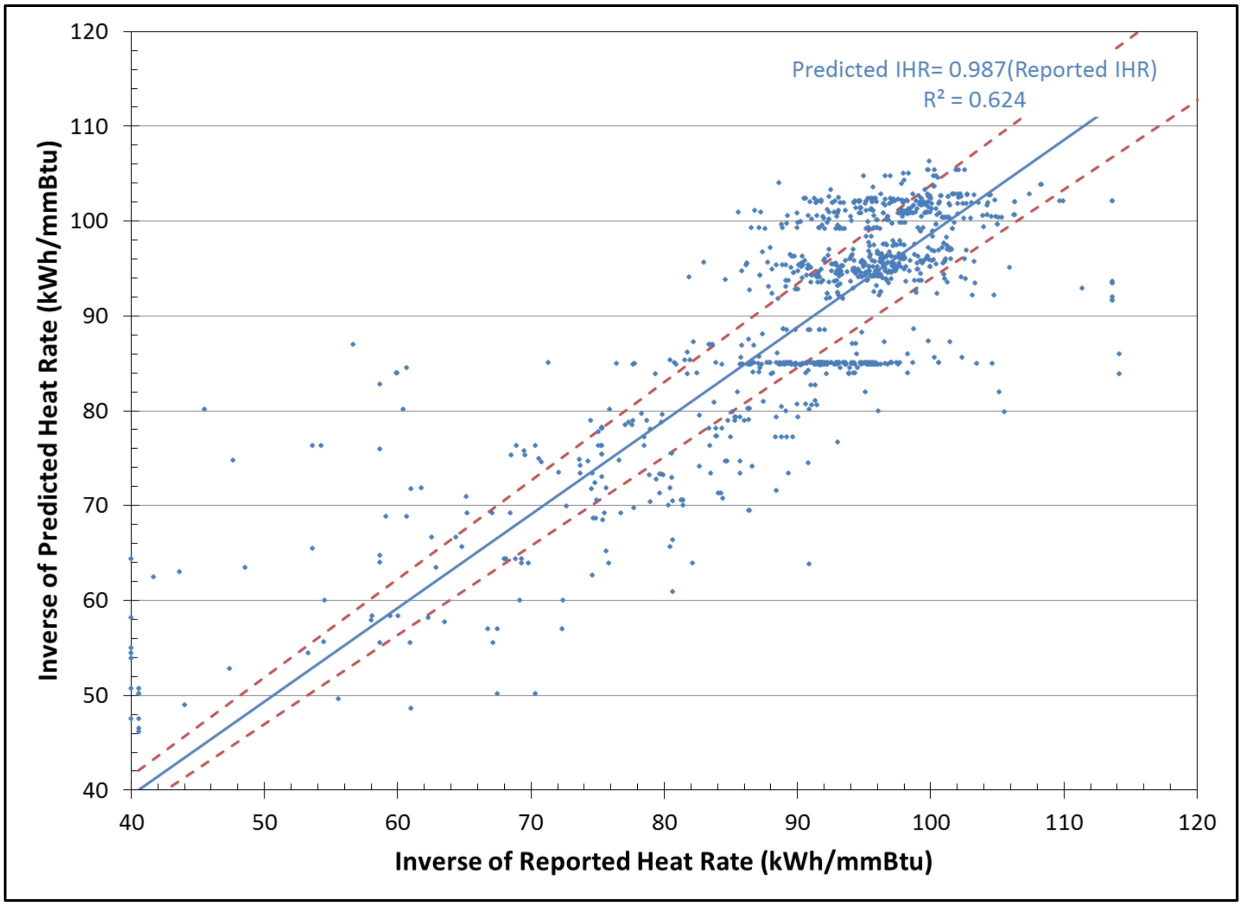

Figure 3-5. Comparison of Reported and Predicted Inverse Heat Rates for All Generators

3.6 Generator Units that Most Likely Can Improve Heat Rates

The generator units in Figure 3-5 can be categorized as follows: Q4) fall to the left of the three lines (least efficient compared to predicted values); Q3) fall to the right of the first red line and to the left of the blue line (third quartile); Q2) fall to the right of the blue line and to the left of the second red line (second quartile); and Q1) fall to the right of all three lines (most efficient compared to the predicted values). The predicted values are already dependent on the unit sizes, fuel types, and installed control devices.

Figure 3-6 presents the fractions of occurrences in each of these quartiles for the different leaves in the decision tree. The figure illustrates that Quartile 1 (those generators with the lowest reported heat rates (highest efficiencies) compared to the predicted heat rates) represents the majority of the generators with nameplate capacities under 181 MW. Generators with nameplate capacities under 181 MW also represent 86% of the Quartile 1 generators, suggesting that the smallest generators have the least room for improvements.

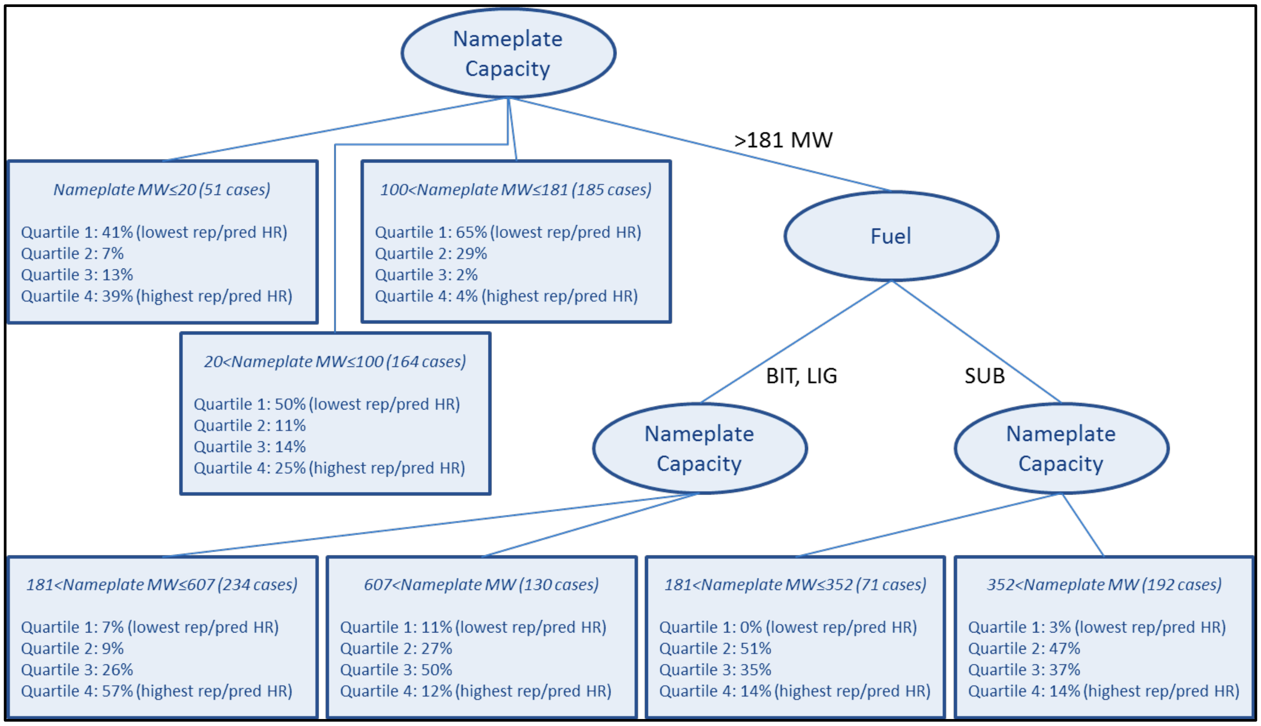

Figure 3-6. Quartiles Comparing Reported Heat Rates to Predicted Heat Rates

The worst data (Quartile 4) shows reported heat rates that are higher than the predicted heat rates. The majority of the Quartile 4 data is represented by the decision tree leaf in Figure 3-6 for generators with nameplate capacities between 181 and 607 MW that are associated with bituminous coal or lignite firing. This statistical observation suggests that finding further heat rate improvements at those plants (with nameplate capacities between 181 and 607 MW that are associated with bituminous coal or lignite firing) would be easiest.

In this statistical manner, with the assumption that the least costly measures have already been implemented, Figure 3-6 suggests that the most costly HRIs (on a per-MWh basis) in future years would be expected at the plants with nameplate capacities less than 181 MW. The least costly heat rate improvements that could be made in future years would be at generators with nameplate capacities between 181 and 607 MW that are associated with bituminous coal or lignite firing. The two leaves in the lower right corner (sub-bituminous coal with nameplate capacities over 181 MW) would offer interim costs in future years because their data lie primarily in Quartiles 2 and 3.

4 Interpretation of Quartile Data

The previous chapter describes how the quartile information was generated, and this chapter compares the measurements and configurations associated with the quartiles. The quartile designations were based on how well the reported heat rates aligned with the predicted heat rates from similar units. When the reported heat rate/predicted heat rate was less than 0.94, the data appear in Quartile 1 (best performance relative to similar units). When the reported heat rate/predicted heat rate was greater than 1.04, the data appear in Quartile 4 (worst performance relative to similar units). Figure 4-1 shows the counts across the quartiles for the different ratios. The full data set can be fit by a normal distribution curve, but the data from the individual quartiles cannot.

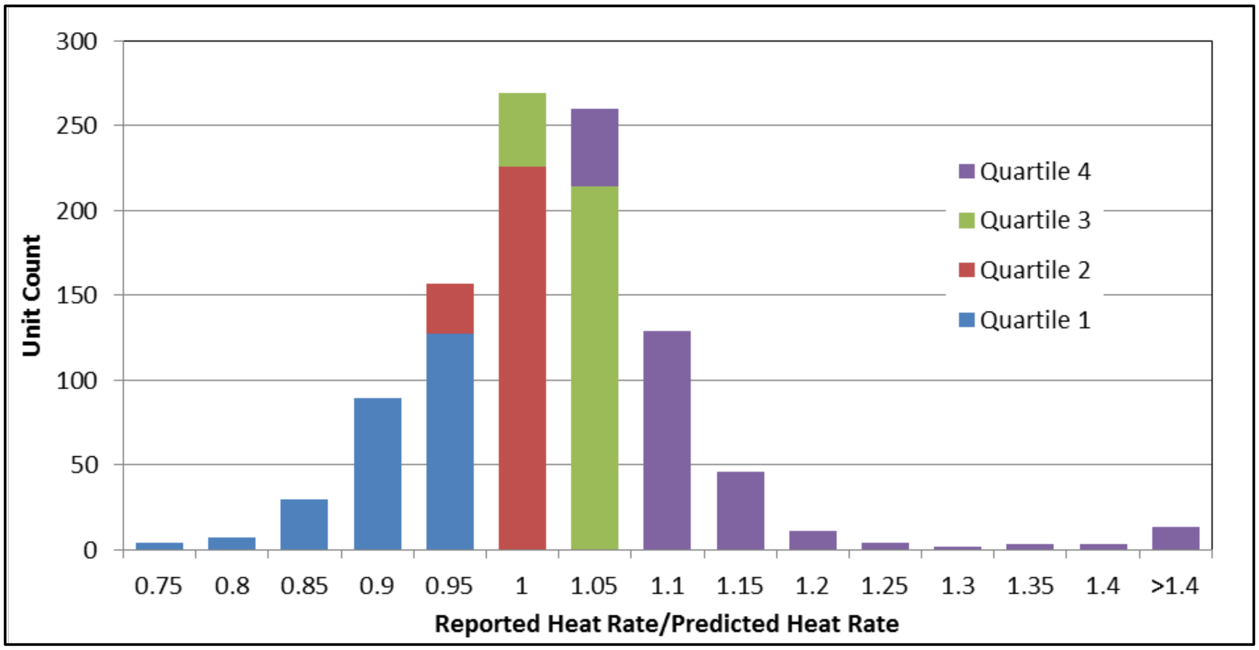

Figure 4-1. Distribution of Units across the Quartiles for Reported Heat Rate/Predicted Heat Rate Ratio

The means and standard deviations for the numeric parameters are shown in Table 4-1 for the four quartiles. Note that the standard deviations only give a sense of the data variability, but do not imply a normal distribution of the data within any of these quartile subsets. In particular, Quartiles 1 and 4 often represent a single tail of a data set.

Of particular note in Table 4-1 is that the average EIA-reported heat rates are higher than those reported in the EPA CAMD data set for all four quartiles. The EIA-reported heat rates are a composite from five years of data,[29] but the EPA CAMD data set represents just 2012. Nationally the year 2012 had more cooling degree days than any other year from 2006 through

[29] Email correspondence from Eric Krall of EIA on November 7, 2014.

Table 4-1. Distributions of Numeric Parameters among the Quartiles

	Quartile 1 (best)	Quartile 2	Quartile 3	Quartile 4
Measured Parameters				
Heat Rate (Btu/kWh)	11,200 ±1,400	10,700±1,100	10,800±1,400	12,600±3,800
CAMD 2012 Heat Rate (Btu/kWh)	10,400±1,200	9,900±900	10,000±1,100	10,300±1,200
Online Year	1964±16	1972±15	1974±12	1970±12
Variable O&M Cost ($/MWh)	3.5±1.5	2.0±1.0	2.0±1.2	2.8±1.6
Annual Fixed O&M Cost ($/kW)	55 ±19	42±16	43±17	48±18
Annual Capital Additions ($/kW)	16±31	19±37	17±20	20±34
Heat Input (billion Btu)	5,500 ±7,400	24,000± 18,000	28,000± 19,000	17,000±14,000
Gross Load (GW-h)	550±790	2,500± 2,000	2,900± 2,000	1,700±1,500
Nameplate Capacity (MW)	150 ±170	430±290	510±290	330 ±250
FGD In Service Year	1981±12	1983±12	1982±11	1980±10
FGD Cost Total ($K)	130,000±140,000	160,000±130,000	170,000±250,000	160,000±220,000
FGD Total O&M Cost ($K)	4,100±3,700	4,200±3,300	5,700±7,400	5,800±5,400
FGP In Service Year	1981±12	1983±12	1982±10	1980±10
FGP Installed Cost ($K)	8,200 ±15,600	18,000 ±21,000	26,000±39,000	13,000±15,000
FGP Emission Rate (pounds per hour)	99 ±180	180±200	250±240	210±260
FGP Hours In Service	4,100 ±3,000	6,600±2,100	6,400±2,300	5,400±2,500
Cooling System In ServiceYear	1963±16	1973±15	1974 ±12	1970 ±11
Intake Rate at 100% (cubic feet per second)	520±720	480±610	370±700	440±660
Number of Federal Air Quality Programs	4.5±3.0	4.9±2.6	4.8±2.6	4.9±2.8
Computational Parameters				
NPC term in "Slope Function Analysis"	88±12	95±6	95±8	91±11
Slope Function (reported)	1.04±0.10	0.99±0.05	0.98±0.04	0.92±0.11
Slope Function (predicted)	0.93±0.07	0.97±0.05	1.00±0.05	1.01±0.07
Predicted Heat Rate (Btu/kWh)	12,600±1,800	11,000±1,200	10,700±1,400	11,000±2,500
Number of Missing Data Reports Used for Predictions	1.2±0.8	0.7±0.7	0.5±0.7	0.7±0.8
Reported Heat Rate/Predicted Heat Rate	0.89±0.04	0.97±0.01	1.01±0.01	1.11±0.11
Inverse Heat Rate Reported (kWh/MMBtu)	91±10	95±8	94±9	84±16
Inverse Heat Rate Predicted (kWh/MMBtu)	81±10	92±8	95±9	92±14

2013,[30] so the EPA CAMD rates may reflect that units were operated closer to capacity in 2012 than in some other years.

[30] National Weather Service Climate Prediction Center, *Degree Days Statistics*. Downloaded on November 11, 2014, from http://www.cpc.ncep.noaa.gov/products/analysis_monitoring/cdus/degree_days/.

Among the measured numeric parameters in Table 4-1, the four quartile means only show a consistent trend for a single parameter, FGD [flue gas desulfurization] Total O&M Cost. The means show a significant step (from $4.2M to $5.7M) when moving from Quartile 2 to 3, but the standard deviations are on the same order of magnitude as the means (indicating significant uncertainty). When the FGD Total O&M Cost was normalized for nameplate capacity or for heat input, the same trend toward rising costs with increasing quartiles was not observed. Only 367 records were populated and are reflected in this comparison (36 from Quartile 1, 92 from Quartile 2, 135 from Quartile 3, and 104 from Quartile 4), so more information about the other plants could help investigators understand the importance that this parameter might have on plant efficiency.

The subsections below discuss some observations about the distribution of parameters among the quartiles, including cases where the single parameters did not place the data in alternate quartiles (i.e., affect relative performance). A previous study[31] found that relationships between single parameters (e.g., subcritical versus supercritical boilers) were often confounded by other competing factors. For example, almost all the highly efficient supercritical boilers were built between 1967 and 1980, affecting the heat rates for units built around that time but with high operational costs.

4.1 Subcritical Versus Supercritical Boilers

Only 17 records were labeled as “N” for subcritical, and 560 others were labeled as “Y.” This wide disparity in record numbers gives at least one explanation why the models did not use this parameter in developing their descriptions.

Staudt and Macedonia cite subcritical boilers as having higher heat rates than supercritical ones, but the examination of reported net heat rates showed no difference between supercritical and subcritical boilers. Staudt and Macedonia speculate that the older age of operating supercritical boilers might mean that more up-to-date technologies could replace the older ones at these plants. However, they did not investigate which equipment had been updated. This speculated opportunity was not evident in the Leidos data analysis: eleven of the seventeen supercritical units fell into Quartiles 1 and 2.

4.2 States

Of the states with at least ten generator records in the database, Table 4-2 shows which had a majority of records in any given quartile. These state rankings are deceptive in that one might think that the heat rates for New York are better than those in Maryland. However, Figure 4-2 shows that the mean of the New York heat rates for the seven Quartile 1 generators are actually higher than those for the means for Quartile 4 generators in Maryland.

Table 4-2. States Whose Generators Mostly Fall into a Single Quartile

Quartile 1 (best)	Quartile 2	Quartile 3	Quartile 4 (worst)
New York (7/13)	Wyoming (13/24)	Arkansas (8/13) Oklahoma (5/10) West Virginia (14/28)	Maryland (10/13)

[31] Staudt, J.E. and J. Macedonia, “Evaluation of Heat Rates of Coal Fired Electric Power Boilers,” Power Plant Pollutant Control “Mega” Symposium, Baltimore, Maryland, August 2014.

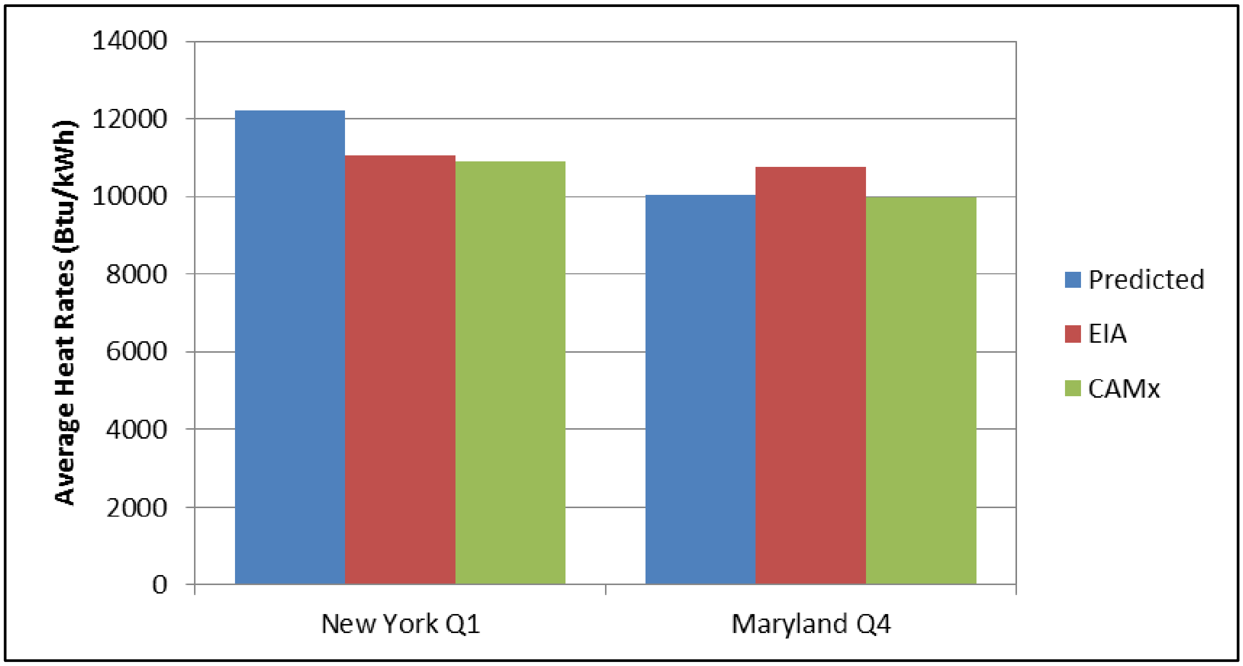

Figure 4-2. Comparisons of Heat Rates for Select Data Subsets by State and Quartile

Maryland's generators may have had higher 2012 heat rates calculated by EIA during the implementation of Maryland's Healthy Air Act when new control devices began operation at these particular plants (2009-2013).[32] The CAMD rates, based on just 2012, align more closely with the predicted rates in Maryland.

4.3 ECP Plant Types

With regard to plant types,[33] Table 4-3 describes the disposition of the different classifications among the quartiles. Figure 4-3, Figure 4-4, and Figure 4-5 show how the various controls appear in the four quartiles. More than 70% of the units in Quartile 1 did not have FGD controls (Figure 4-3), more than 60% of the units in Quartile 1 did not have SCR controls (Figure 4-5), but particulate controls were included on almost every Quartile 1 unit (Figure 4-4).

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[32] The Maryland Healthy Air Act, Maryland Department of the Environment. Downloaded from http://www.mde.md.gov/programs/Air/ProgramsHome/Pages/air/md_haa.aspx on November 11, 2014.

[33] ECP types defined on page vii.

Table 4-3. Distribution of ECP Plant Types among Quartiles

Particulate Control	Baghouse				Cold-Side ESP				Other/None			Integrated Gasification
Other Controls	**No FGD**	**Wet FGD, no SCR**	**Wet FGD, SCR**	**Dry FGD**	**No FGD**	**Wet FGD, no SCR**	**Wet FGD, SCR**	**Dry FGD**	**No FGD**	**Wet FGD, no SCR**	**Wet FGD, SCR**	
Quartile 1 (best efficiency relative to prediction)	32	13	5	27	148	15	11	1	1	1	--	3
Quartile 2	15	24	6	25	110	27	36	1	6	6	--	--
Quartile 3	18	16	11	21	69	32	71	6	4	6	3	--
Quartile 4 (worst efficiency relative to prediction)	20	15	6	9	99	39	51	7	10	--	1	--
Grand Total	**85**	**68**	**28**	**82**	**426**	**113**	**169**	**15**	**21**	**13**	**4**	**3**

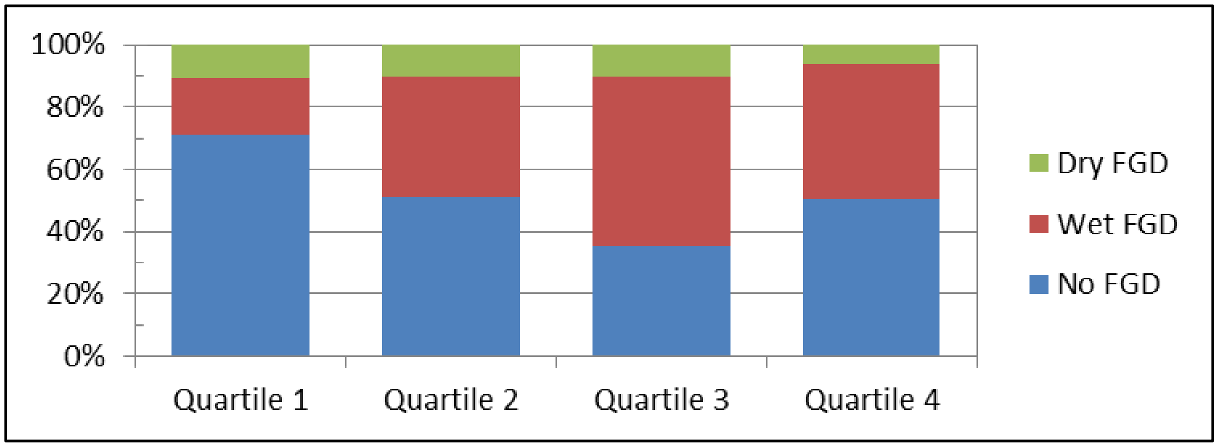


Figure 4-3. Distribution of FGD Type among the Quartiles

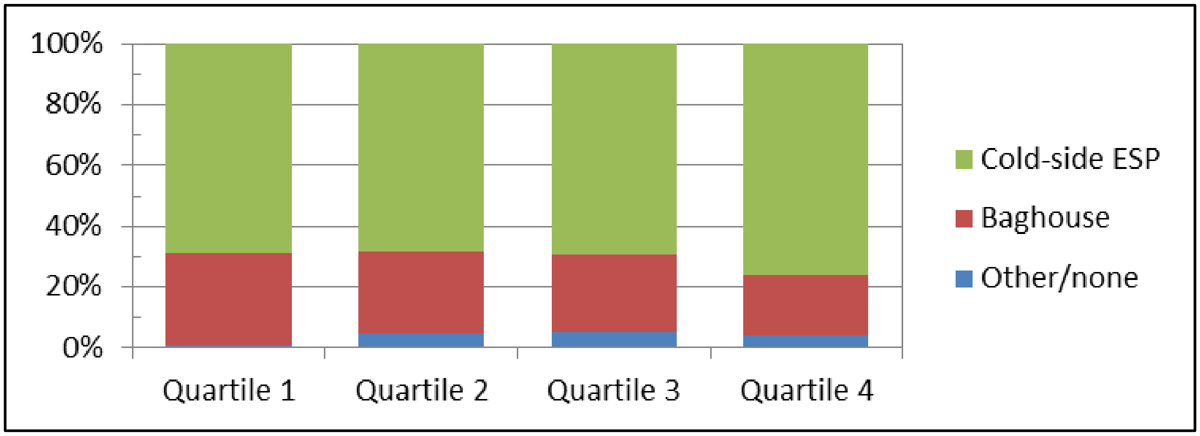


Figure 4-4. Distribution of Particulate Control Types among the Quartiles

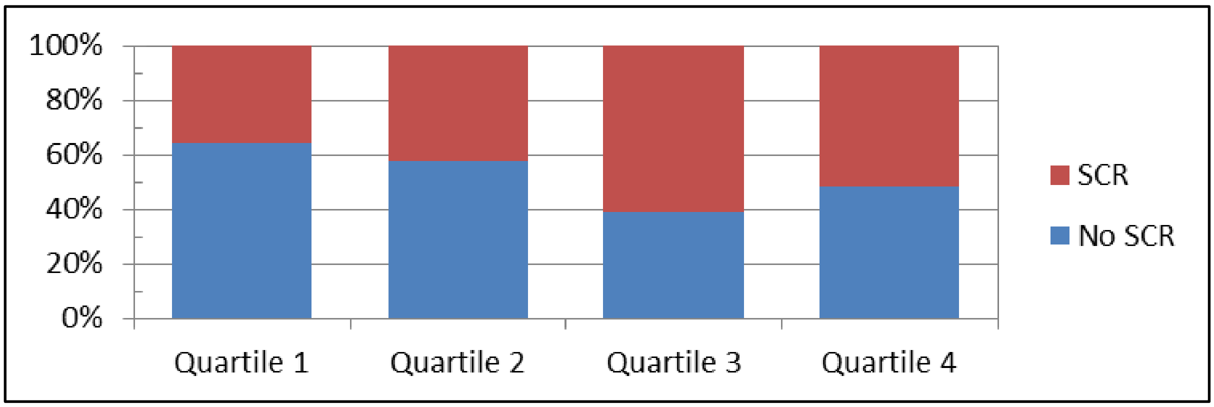


Figure 4-5. Distribution among the Quartiles Based on Selective Catalytic Reduction (SCR) Usage

4.4 Heat Rates

Staudt and Macedonia reported that low-capacity boilers had much higher heat rates. They explained that this would be partly due to the fact that low pressure steam cycles are likely more common in smaller boilers. Figure 4-6 shows the distribution of CAMD 2012 heat rates among the generator units, but no obvious differences are noted in the distribution for the four quartiles.

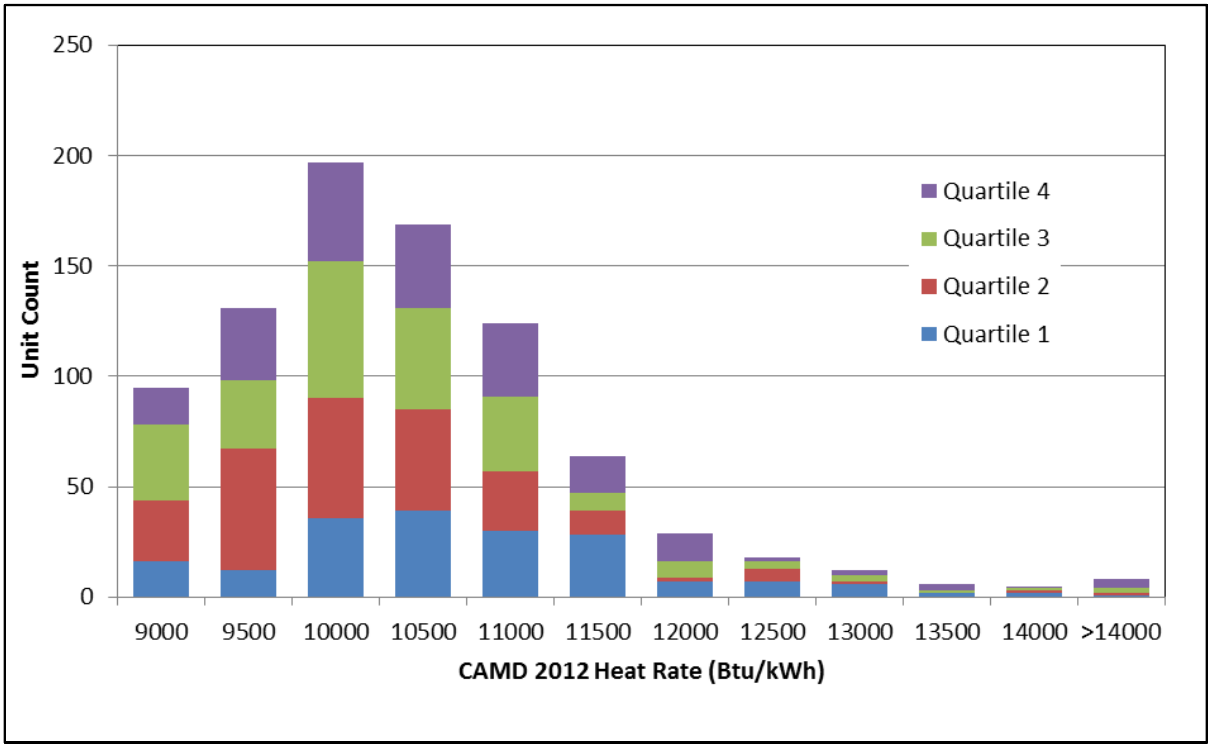


Figure 4-6. Distribution of CAMD 2012 Heat Rates among Quartiles

The distribution of EIA-reported heat rates are shown in Figure 4-7, but they show somewhat different trends. Only Quartiles 1 and 2 have heat rates less than 10,000 Btu/kWh. Quartile 4 generally is highly represented at the higher heat rates. Because the quartile distinctions are based on heat rates, these trends were not unexpected.

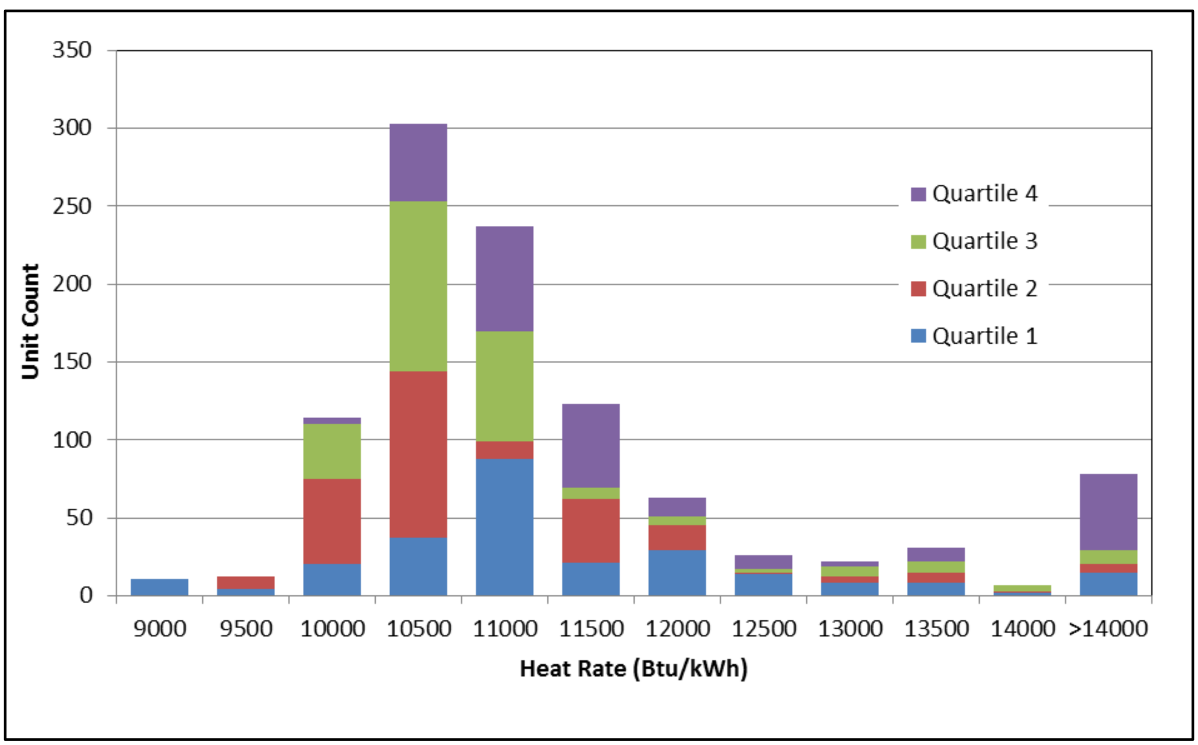


Figure 4-7. Distribution of EIA-Reported Heat Rates among the Quartiles

4.5 Online Year

Figure 4-8 shows the number of units in each quartile based on the online year. The most efficient units (Quartile 1 in blue) generally fall into the older units built before 1970, but this finding may not be intuitive. However, the older units are generally the smaller units and will be compared to other smaller units with the ones that are still operating representing only those with economical designs. The older units may also have fallen into environmental programs that grandfathered their high pollutant emission rates until after more efficient control technologies were developed.

Units going online between 1970 and 1985 do not generally fall into the most efficient quartile, indicating that they may currently be the units best suited to HRIs. The history associated with these units (e.g., replacements and upgrades) might provide reasons why units of this vintage do not perform as well as units going online in other years. Staudt and Macedonia reported little effect from the online year.

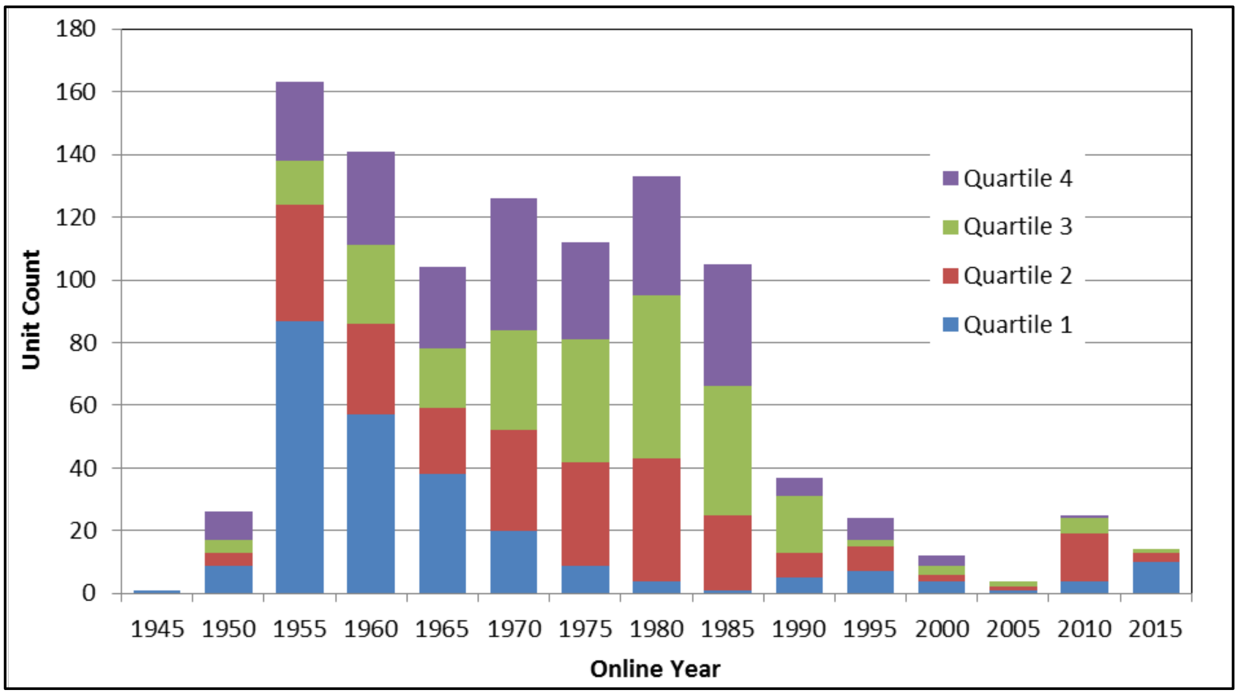


Figure 4-8. Distribution of Quartiles Based on Online Year

4.6 Planned Retirement Year

Only 203 records listed planned retirement years, and the years ranged from 2012 to 2021. Figure 4-9 displays the number of units from each quartile against the planned retirement years. A considerable number of the planned retirements fell into Quartile 1, and this is likely because they represent the earliest online years. Figure 4-10 supports this supposition with its display of the online years for only the units with planned retirement years. Note in Figure 4-10 that the majority of retiring units going online after 1965 fall into Quartile 4 (the worst performing units).

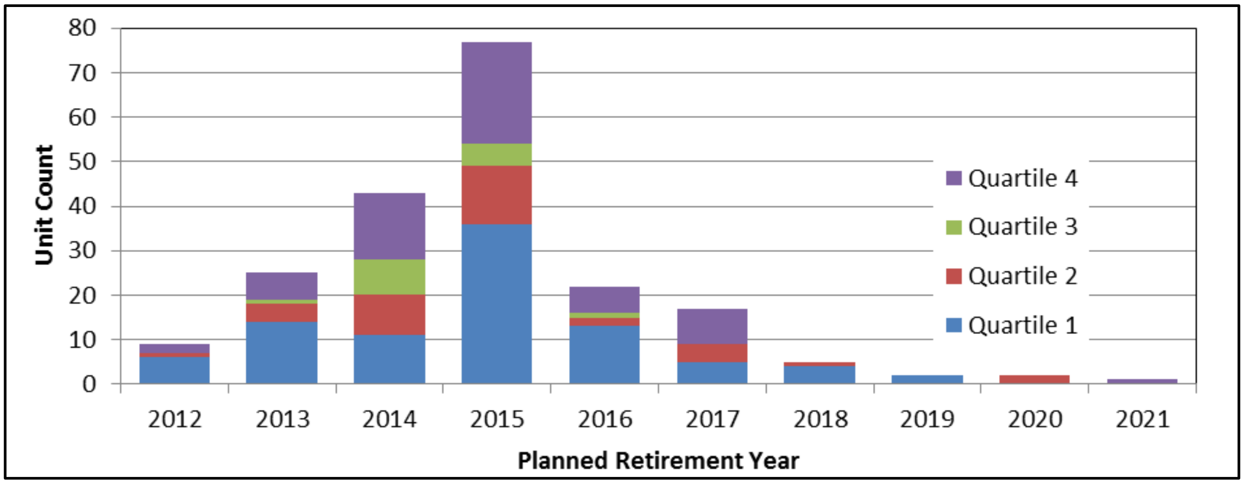


Figure 4-9. Distribution of Quartiles for Units Listing Planned Retirement Years

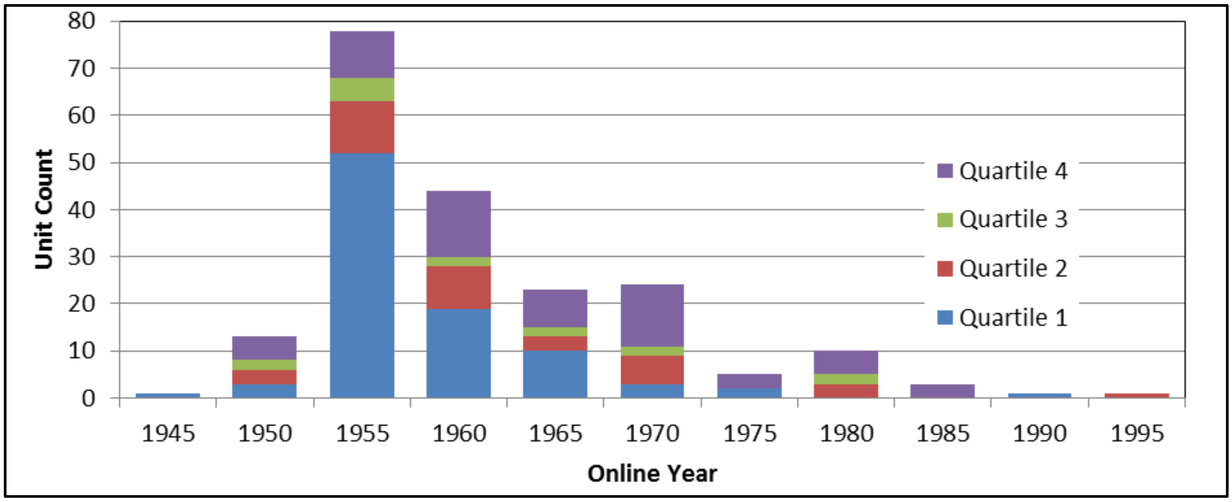


Figure 4-10. Distribution of Quartiles among Online Years for Units Listing Planned Retirement Years

4.7 Variable O&M Costs

The AEO 2014 includes the Variable O&M costs that range from $0.57/MWh to $6.54/MWh for coal-fired units. Variable O&M costs are a key input for calculation of levelized costs, and the reported AEO 2014 values include fuel costs. Figure 4-11 shows the distribution of Variable O&M costs among the quartiles, and Figure 4-12 shows the distribution only for the larger units (over 100 MW). The differences between Figure 4-11 and Figure 4-12 appear in the bars to the right of $2.5/MWh because smaller units do not have the lower operational unit costs. The Variable O&M costs tend to be highest for the best performing units (Quartile 1), and this likely reflects the fact that the best performing units will be economical even when the fuel costs are high.

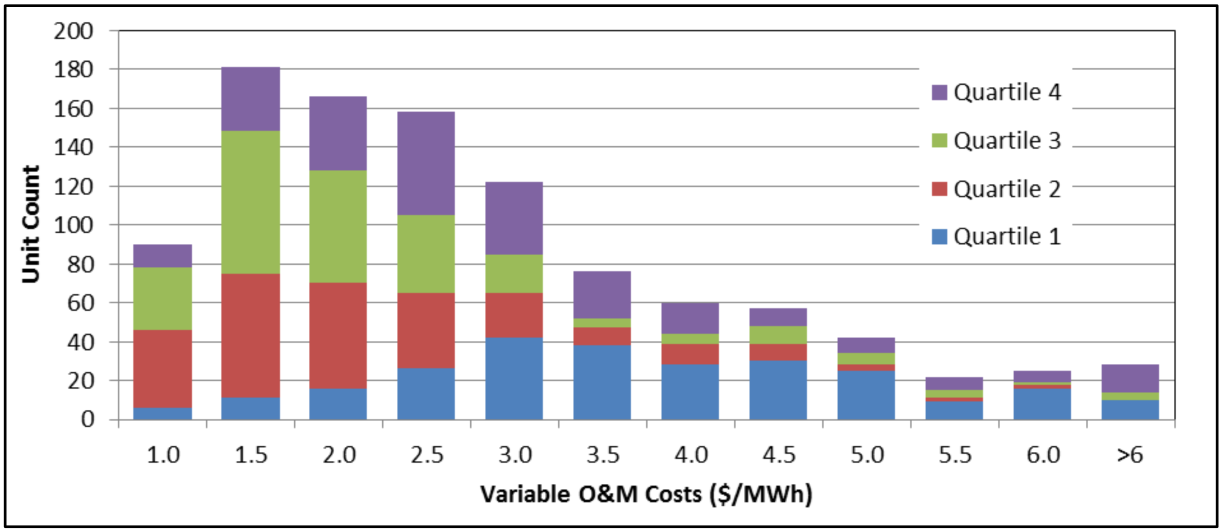


Figure 4-11. Distribution of Quartiles Based on Variable O&M Costs (Including Fuel Costs)

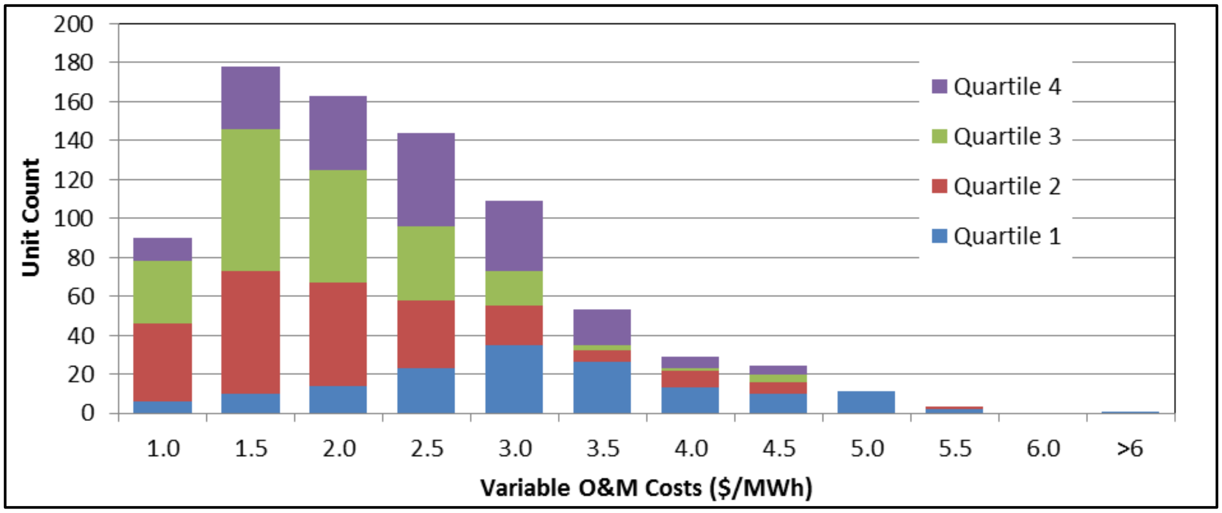


Figure 4-12. Distribution of Quartiles Based on Variable O&M Costs (Including Fuel Costs) for Units with Nameplate Capacities Over 100 MW

The Variable O&M cost distributions for Quartile 4 (worst performing units) are higher than those for Quartiles 2 and 3. This tendency toward higher Variable O&M costs may reflect that more fuel (and thus more fuel cost) is incurred in Quartile 4 units to generate the same amount of energy.

4.8 Fuel Choice

Ninety percent of the records had primary fuels listed as bituminous, sub-bituminous, lignite, or waste coal. Table 4-4 presents the numbers of units as they were distributed among the quartiles based on the primary fuel usage. Upon examination of the first five rows of this table, the bituminous coal units appear more frequently in Quartiles 1 and 4, but the sub-bituminous units dominate Quartiles 2 and 3.

Table 4-4. Number of Generator Units in Quartiles Based on Primary Fuel Usage

	Quartile 1 (best)	Quartile 2	Quartile 3	Quartile 4
All Units				
Bituminous	146	70	124	167
Sub-bituminous	55	160	108	60
Lignite	1	8	11	8
Waste Coal	4	--	1	1
Not reported	51	18	13	21
Units with Nameplate Capacities Less than or Equal to 100 MW				
Bituminous	54	7	11	23
Sub-bituminous	24	8	12	20
Lignite	1	2	--	--
Waste Coal	4	--	1	1
Not reported	23	6	6	19
Units with Nameplate Capacities Greater than 100 MW but Less than 181 MW				
Bituminous	81	20	--	26
Sub-bituminous	26	26	--	4
Lignite	--	2	--	--
Waste Coal	--	--	--	--
Not reported	8	3	2	2
Units with Nameplate Capacities Greater than 181 MW				
Bituminous	11	43	111	142
Sub-bituminous	5	126	96	36
Lignite	--	4	11	8
Waste Coal	--	--	--	--
Not reported	20	9	5	--

Data are also presented in Table 4-4 used different cut points based on nameplate capacities. These cut points represent the decision nodes in the piecewise linear regression models described in the last chapter. In the group of units with nameplate capacities less than or equal to 100 MW, all fuel types are more likely to appear in Quartiles 1 and 4 than in the center quartiles. This finding is a reflection of the high variability in EIA heat rates for the smaller units.

The piecewise model for the units with nameplate capacities greater than 100 MW but less than 181 MW shows a bias toward Quartiles 1 and 2, but all fuels are biased toward these quartiles. This result was anticipated because the model for this node has the same correction for both bituminous and sub-bituminous fuel.

For units with nameplate capacities greater than 181 MW, two rules apply for bituminous and lignite fuels and two other rules for sub-bituminous fuel. The rules for sub-bituminous coal again favor Quartiles 2 and 3, but the rules for bituminous and lignite fuels tend to put more units in Quartiles 3 and 4. The computed Slope Function is greater than 1.00 at 81% of the bituminous/lignite units in the largest size category, so the bias toward low performance might be explained by the model bias rather than actual plant performance.

4.9 Total FGD Cost

Staudt and Macedonia reported that the FGD-controlled units generally were more efficient than unscrubbed units, but not by much. When a dry scrubber was added to the unit (comparing against historical data), the heat rates did increase. However, Staudt and Macedonia did not determine a directional correlation for the addition of wet scrubbers.

The data in this study represent only single snapshots in time of a unit's heat rates and not the effect of adding new units. The parameter called FGD Cost Total ranged from $21,000 to $1.5 billion in the EIA-923 forms for 2012. Fifty-six records showed a total FGD cost exceeding $325M (81% to structure, 4% to disposal, and 15% to other costs).

Figure 4-13 depicts how the Total FGD Cost parameter is distributed among the quartiles for the 460 units. The total FGD cost for the majority of the units is less than $100M, and all four quartiles have their largest counts in the first two bins. Therefore, the total FGD cost did not appear correlated to the unit performance.

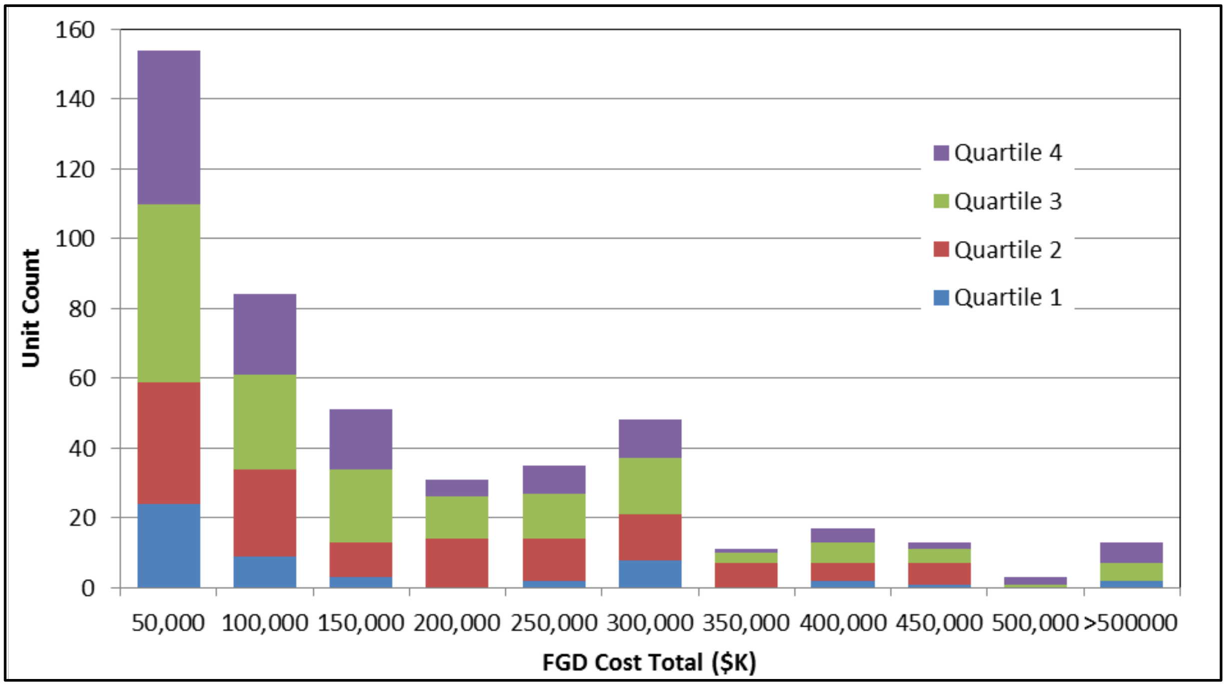


Figure 4-13. Distribution of Total FGD Cost (Thousands of Dollars) among Quartiles

4.10 FGP Collector Classification and Hours in Service

FGP collectors were reported for 883 units in ten different categories (3 baghouse types, 4 ESP types, 2 cyclones, wet scrubber, and other type), but the FGP categories were compiled into five types in Figure 4-14. Figure 4-14 shows that most FGP collectors fall into the ESP categories and that ESP systems are more often associated with Quartile 4 than the other quartiles. Eighty-eight percent of the Quartile 4 records with FGP collectors use ESPs, but the percentages are only near 70% (± 3%) for the other three quartiles.

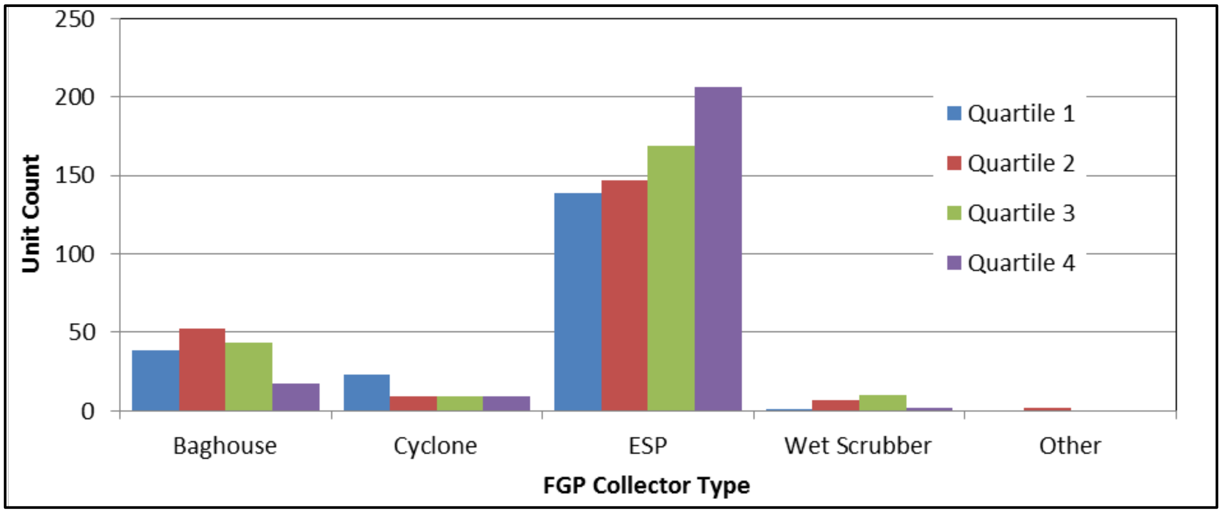


Figure 4-14. Distribution of Quartiles among FGP Collector Types

This finding indicates that the FGP collector type might be associated with the unit performance (this parameter does appear in five of the seven slope function models) or at least correlate with another parameter that shows similar patterns. Figure 4-15 shows the distribution of FGP collector types based on the online year for the generator unit. The figure clearly indicates that the ESP technology was installed on a majority of the units that went online before 1990, but baghouse technologies are more common in newer units. Figure 4-8 showed few Quartile 4 units that went online after 1990, so the lack of ESPs in newer units may indicate why Figure 4-14 indicated a tendency of ESPs toward Quartile 4.

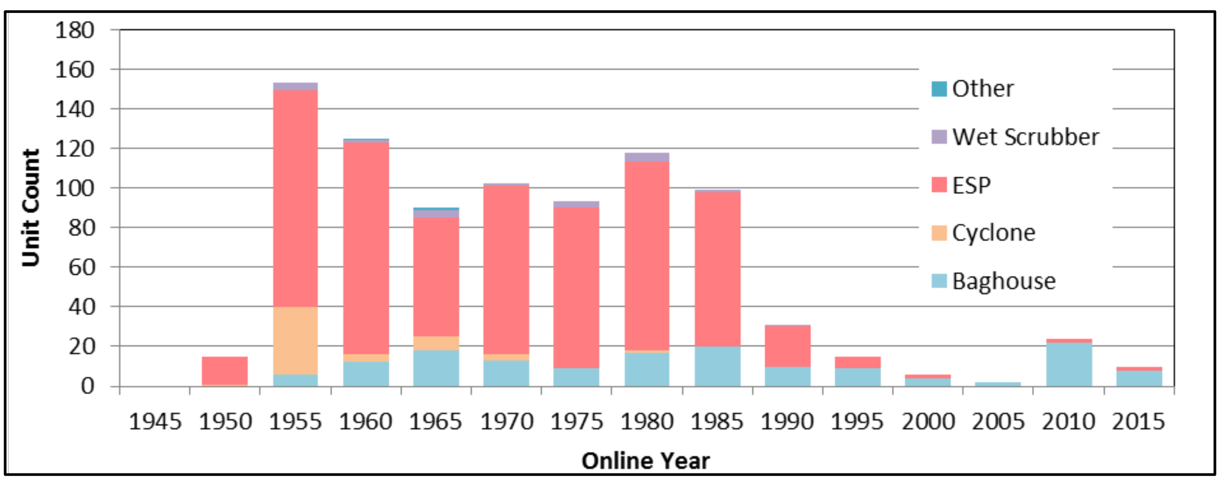


Figure 4-15. Distribution of FGP Collector Types with Online Year

Table 4-1 showed that the average numbers of FGP service hours in 2012 were lower for Quartile 1 and Quartile 4 than the other two quartiles, indicating that these units are less likely to produce base load electricity. Figure 4-16 shows that the distribution of FGP service hours for the four quartiles as fractional counts. This display clearly shows that Quartile 1 units are more likely to operate FGP controls less than 4000 hours a year than greater that, but the shorter operational hours appear less frequently in the other three quartiles.

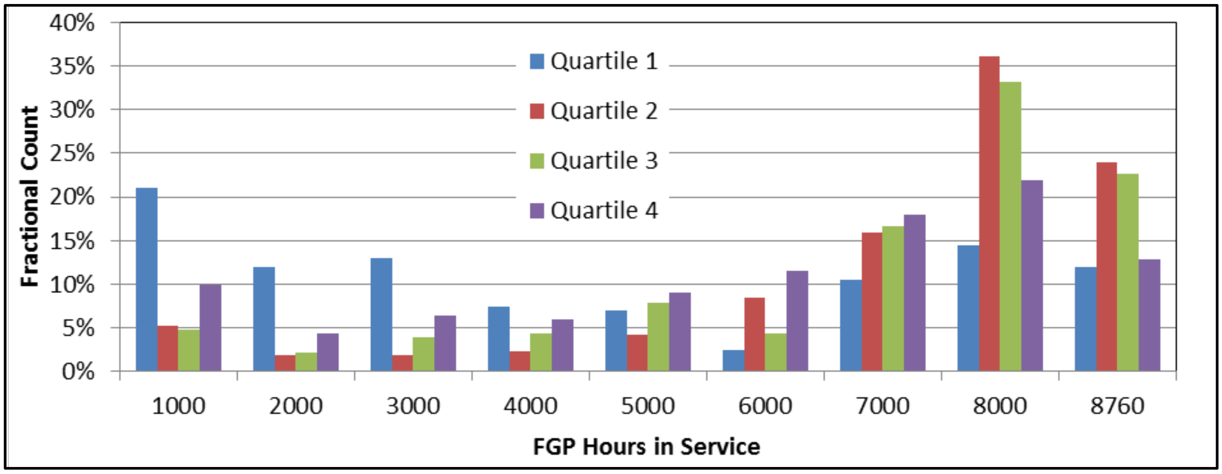


Figure 4-16. Fractional Distribution of FGP Service Hours among Quartiles

4.11 Cooling System Type and In-Service Year

The primary cooling system types were grouped for this analysis:

- Once through systems without pond or canal (427 units with code=ON)
- Cooling ponds or canals (81 units with code=OC or RC)[34]
- Cooling towers (329 units with code=HRF, RF, RI, or RN)[35]
- Other/unknown (3 DC units, 2 OT units, and 185 blank)[36]

Figure 4-17 shows the fractional distributions of the quartiles within each cooling system type. The unknown units are more often represented by Quartiles 1 and 4 because reported rates vary more significantly from predicted rates when information is missing. Quartile 1 represents the largest fraction for the "*Once Through without Pond*" type, and Quartile 3 is the largest fraction for the units with cooling towers. The reason for these observations is likely connected to the in-service years.

[34] OC = Once through with cooling pond(s) or canal(s); RC = Recirculating with cooling pond(s) or canal(s).

[35] HRF = Hybrid: recirculating with forced draft cooling tower(s) with dry cooling; RF = Recirculating with forced draft cooling tower(s); RI = Recirculating with induced draft cooling tower(s); RF = Recirculating with natural draft cooling tower(s).

[36] DC = Dry (air) cooling system; OT = Other.

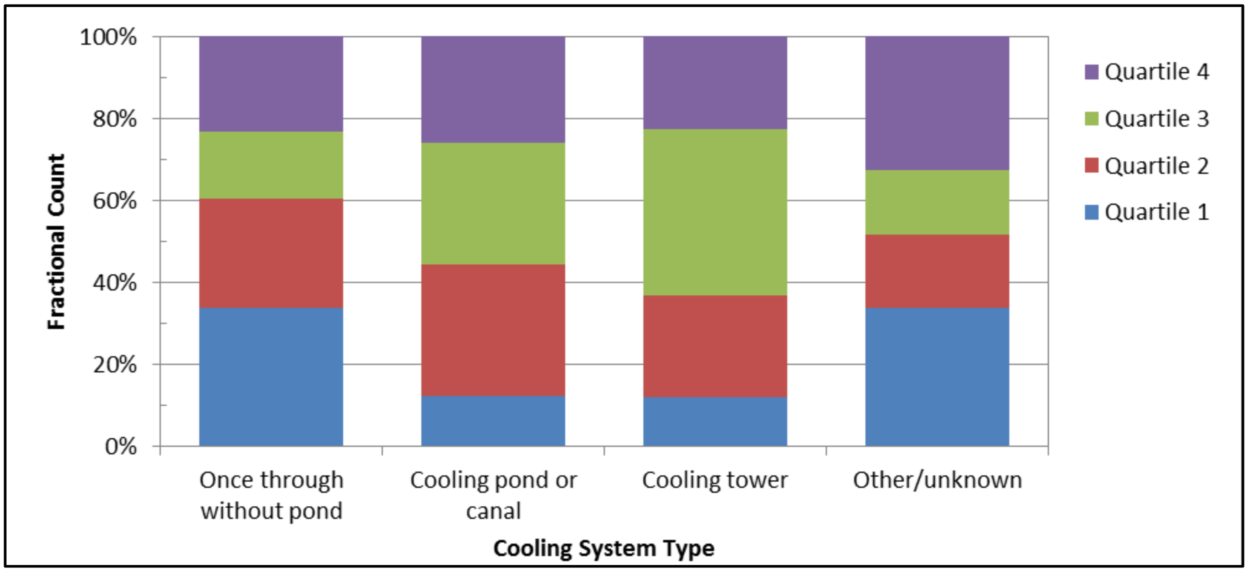


Figure 4-17. Fractional Distribution of the Quartiles within Cooling System Types

Figure 4-18 shows the distribution of the three major cooling system types based on the in-service year. It clearly indicates that the oldest units were predominantly once through systems without ponds, and the newest units are predominantly those with cooling towers. As mentioned in previous subsections, Quartile 1 units are generally more common in older systems, and the largest fraction of Quartile 3 units appear around 1980 in Figure 4-18. These observations tend to explain the frequencies observed in Figure 4-17.

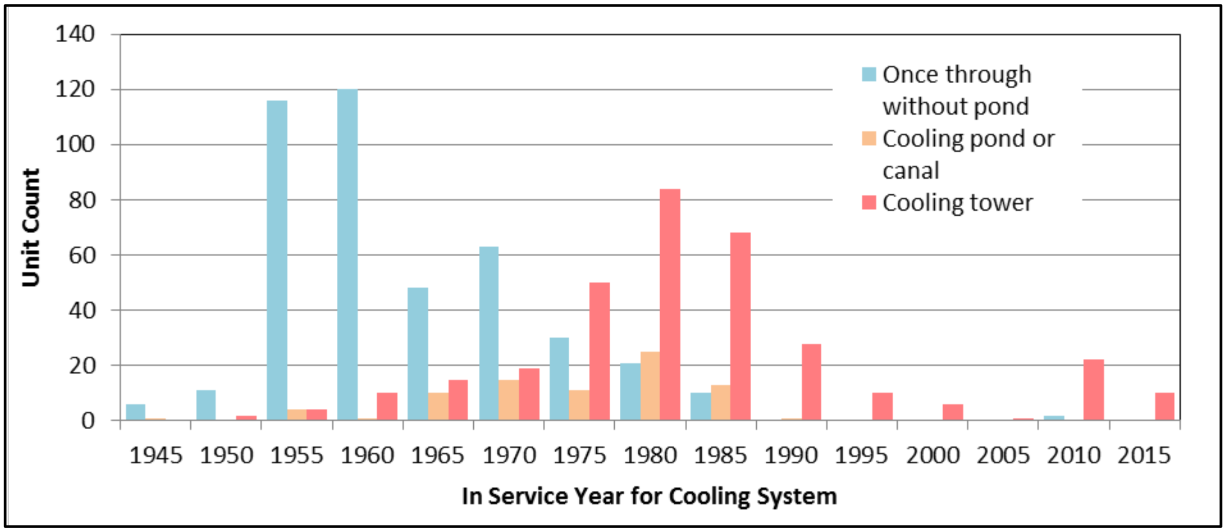


Figure 4-18. Distribution of Cooling System Types among In-Service Years for Cooling Systems

4.12 Number of Federal Air Market Programs Affecting Emissions

The EPA CAMD data set also covers statutory or regulatory based options for tracking and reducing air pollution emissions. Annual information for environmental controls at the generator level is available from the EPA Air Markets Program Data (AMPD) database for facility attributes. The AMPD data contain also information on annual and ozone (May-September) season programs at the generating unit level. The market-based regulatory programs aim to improve air quality through coordinated emission reductions.

The annual programs include:

- Acid Rain Program (ARP),
- Clean Air Interstate Rule (CAIR) NO_x Program,
- Cross-State Air Pollution Rule (CSAPR) annual NO_x (TRNOx), Phase I (TRSO2G1) and phase II (TRSO2G2) SO_2 Programs, and
- Regional Greenhouse Gas Initiative (RGGI)

The ozone season programs include:

- CSAPR ozone season NO_x Program (TRNOxOS),
- CAIR ozone season NO_x Program (CAIROS),
- NO_x SIP Call Program (SIP NOx), and
- NO_x Budget Program (NBP).

Finally, the database indicates when a unit is subject to New Hampshire's NO_x program (NHNOx). None of these eleven program phases began implementation before 1995, and more than 90% of the generator units in the database pre-date the announcements of these programs. Therefore, comparing the heat rate predictions against each of these programs would not be expected to yield significant results. However, some of these programs are implemented at the statewide level (based on unit size), so an accounting of the programs may serve as a surrogate for describing regional behavior. Table 4-5 shows the state names based on the number of market programs coal-fired units there are subject to. In rows with multiple bullets, the table shows that 24 states have some units that are subject to no air market programs and other units subject to 1 to 8 programs.

Table 4-5. Number of Air Market Programs Affecting Generators by State

State	Number of Programs						
	0	1	3	5	6	7	8
Alabama						•	
Arkansas	•		•				
Arizona	•	•					
Colorado	•	•					
Connecticut			•				
Delaware	•			•			
Florida	•			•			
Georgia	•				•		
Iowa	•				•		

State	Number of Programs						
	0	1	3	5	6	7	8
Illinois	●					●	
Indiana	●					●	
Kansas			●				
Kentucky						●	
Louisiana				●			
Massachusetts			●				
Maryland							●
Michigan	●				●		
Minnesota	●		●				
Missouri	●				●		
Mississippi	●			●			
Montana	●	●					
North Carolina	●					●	
North Dakota	●	●					
Nebraska	●		●				
New Hampshire			●				
New Jersey						●	
New Mexico		●					
Nevada	●	●					
New York	●						●
Ohio	●					●	
Oklahoma		●					
Oregon		●					
Pennsylvania	●					●	
South Carolina	●					●	
South Dakota	●	●					
Tennessee						●	
Texas	●				●		
Utah	●	●					
Virginia	●					●	
Washington		●					
Wisconsin	●				●		
West Virginia	●					●	
Wyoming	●	●					

Figure 4-19 shows the quartile distributions based on the number of Federal air market programs. It does not indicate that fewer or more Federal air market programs lean toward particular quartiles. However, Figure 4-20 does show that the generators associated with the highest heat rates are generally affected by no programs, and those with the lowest heat rates (less than 10,500 Btu/kWh) are more likely to be affected by 6 or 7 programs.

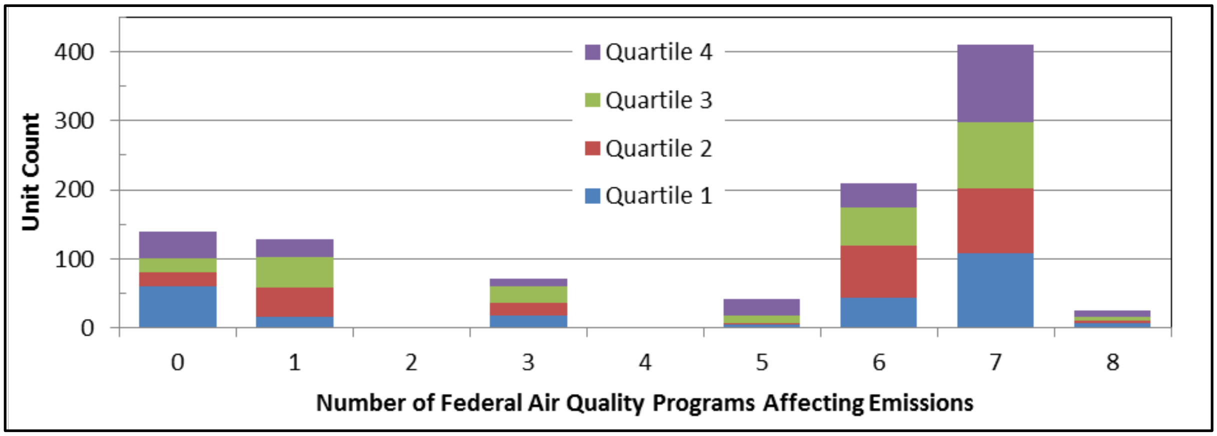


Figure 4-19. Distribution of Quartiles Based on Number of Federal Air Market Programs

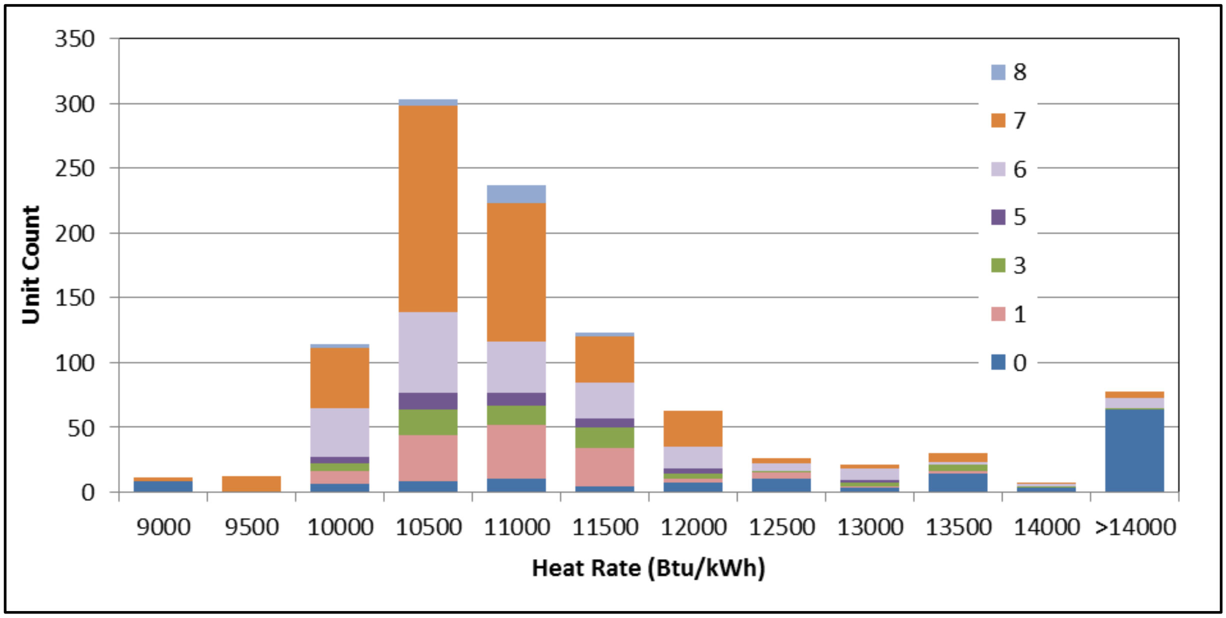


Figure 4-20. Distribution of Heat Rates Based on Number of Federal Air Market Programs

5 Evaluation of Potential HRIs and Associated Costs

5.1 Heat Rate Improvement Options and Valuation

Chapter 2 described a variety of the available published reports discussing heat rate improvements at coal-fired power plants and their associated costs. It illustrated that a wide range of improvements was possible at a wide range of capital and operating costs. This chapter presents the Leidos analysis of what fraction of the units could have the measures applied, the anticipated HRIs, and the anticipated costs (in 2014 dollars).

The improvements are considered in five different plant areas: *boiler island, turbine island, flue gas system, air pollution controls, and water treatment system*. Some previous reports considered regular outage maintenance activities (e.g., replacement of first point heater) as HRIs, but this chapter focuses on non-routine retrofit measures that reflect a change in design or operations.

Considerable overlap exists between the different HRI activities, and many activities cited in the literature might be considered subsets of other activities. To avoid double-counting future potential HRIs in the coal-fired fleet, some subcategories were eliminated. Also eliminated were those measures typically performed as maintenance activities during scheduled outages; these activities restore heat rate but are not considered to actually improve plant performance.

The existing literature also stresses that the HRIs should not be considered additive. The potential efficiency gained by one boiler island HRI should not necessarily be added to another boiler island HRI or HRIs elsewhere at the plant without a full heat rate evaluation. Such an evaluation should also include consideration of the expected unit capacity factor and the expected load changes.

In addition, some activities require significant capital investment and are likely to trigger the New Source Review (NSR) provisions of the Clean Air Act. Installation of additional control systems under the NSR would often negate the HRIs, so special conditions were assigned such that previously uncontrolled systems could not gain HRIs from certain measures that involved high capital cost investments.

Some technologies were also identified as existing only in the R&D or pilot phase at this point. Literature works and patents indicate that some degree of success is being made in these areas, but often readers would find it difficult to classify the HRIs in these pilot studies as maxima or minima. The public literature on these studies generally does not cite costs, so full cost evaluations would be necessary for EIA to establish ranges on the capital, operating, and maintenance costs across all potential plants. The recommendations for these cost evaluations are listed in Chapter 7.

As discussed in Chapter 3, many HRI activities are already underway at coal-fired plants because improved heat rates are associated with fuel cost savings. Therefore, it is assumed that units falling into Quartile 1 had most likely already made improvements and that Quartile 4 units were the least likely to have made improvements. Expert Leidos-based experience was used to judge how commonly practiced the various HRI activities had been deployed through 2014:

- **Novel** – still available for Quartiles 1, 2, 3, and 4
- **Uncommon today** – available for Quartiles 2, 3, and 4
- **50/50 today** – available for Quartiles 3 and 4

- **In most units today** – available for Quartile 4
- **Maybe in 10 years** – available for Quartiles 1, 2, and 3 (assuming that Quartile 4 units would make other improvements before investing in the newer technologies)

Initially 56 HRI activities were under consideration, but the criteria listed in the preceding paragraphs reduced the list to just the 29 measures shown in Table 5-1. Table 5-1 presents the highest HRIs and maximum capital costs, and Table 5-2 presents the minima. Both of these tables include *special conditions* and *notes* columns that identify the source and/or assumptions associated with the HRI valuations and capital costs.

The approach used to *generally* assess the range of HRI potential for the large numbers of coal-fired units of varied types and existing condition is as follows:

- Detailed assessment of individual units or sample cases was not possible within the scope of this project, requiring a much more general approach based on literature data and engineering experience and judgment associated with decades of coal-fired plant upgrade projects. *Note that site-specific equipment review and related cost appraisals are the most appropriate methods for assessing all required equipment, material, and installation and operating labor for unique projects.*
- The 2009 S&L Report results were used as the reference values for those HRI options covered in this report. Leidos engineering staff considered the maximum and minimum HRI values established in the report and used engineering experience and judgment and other available internal and literature data (as discussed in Section 2 of this report) to determine if updates were deemed appropriate. For all HRIs, Leidos staff either decided on more conservative HRI values or accepted the S&L Report values.
- Other HRI options not included in the S&L Report were assessed based on Leidos experience, engineering judgment, and internal and literature data sources as available.
- Literature sources reviewed are presented in Section 2. Key sources used were:
    - Coal-Fired Power Plant Heat Rate Reductions, Prepared by Sargent & Lundy for Perrin Quarles Associates, Inc., under U.S.EPA Contract No. EP-W-07-064, January 22, 2009.
        - Study of various methods to reduce the heat rate of existing U.S. coal-fired power plants in a range of sizes − 200 MW, 500 MW, and 900 MW (see Section 2.1)
        - Cost basis – Vendor quotes
        - Cost Year basis – 2008 (mid-year assumed)
    - Reliable & Resilient / The Value of Our Existing Coal Fleet - An Assessment of Measures to Improve Reliability & Efficiency While Reducing Emissions, National Coal Council study at the request of the U.S. Department of Energy, May 2014.
        - Study identifies various methods to reduce the heat rate of existing U.S. coal-fired power plants for plants of various sizes (see Section 2.1)
        - Cost basis – Various literature and regulatory sources
        - Cost Year basis – various

- ASME Energy Forum, Power Plant Efficiency: Saving Fuel, Officiated by Licata Energy and Environmental Consulting, September 25, 2014.
  - Presenting organizations were: Anthony Licata (Cycling Ops./Air Heaters /Emissions Controls); Burns & McDonnell (Impact of New Source Review); Siemens Energy (Turbine Island); Robert Sommerlad (Combustion/ Boiler Island / Neural Networks & Intelligent Sootblowing)
- EPRI Range and Applicability of Heat Rate Improvements Technical Update. April 2014. Electric Power Research Institute Report Number 3002003457.
  - Summarizes methodologies and tools for assessing and implementing measures for improving heat rate in coal-fired power plants. In addition, the report attempts to better bracket the range of achievable improvements possible for an existing coal-fired power plant.
  - No cost data included

5.2 Heat Rate Improvement Cost Estimation

Tables 5-1 and 5-2, respectively, present the maximum and minimum estimates for the total capital investment (order of magnitude) associated with HRI equipment modifications. Table 5-3 presents a comparable list of the associated fixed and variable O&M costs associated with each HRI.

Costs for the HRI options included in the S&L report (vendor quotes) were accepted for use in this study, but were escalated to November 2014 dollars (from mid-year 2008) using the RS Means Construction Facilities Cost Data - 28th annual edition Historical Cost Indexes.

- Historical Cost Index for 2008 = 180.4
- Historical Cost Index Estimated for November 2014 = 198.2
- Calculated escalation from 2008 to November 2014 = 10%

The same composite construction cost escalation index has been used for both capital costs and fixed and variable O&M because the S&L Report did not break out the cost split between materials, labor, and equipment.

Readers should think of these numbers and the upgrade choice in NEMS as the heat rate evaluation findings that are conducted at a plant prior to a planned outage. A utility may conduct/contract a heat rate evaluation prior to an outage, and the results will tell them the expected HRI and potential cost. Sometimes no cost-prohibitive solutions will be identified, so the HRI and cost would both be zero.

If many of these evaluations are done across a broad selection within one ECP type, the average HRI times the total number of generators will represent the *total potential fuel savings* (TPFS), and the average cost times the total number of generators will represent the *total costs* (TC). The same TPFS and TC will result if the average non-zero HRI is multiplied by the total number of generators (with non-zero HRIs) and the average non-zero cost is multiplied by the total number of generators (with non-zero HRIs). The ratio of TC to TPFS will also be the same and represents a national average improvement. Therefore, no distortion is observed in the data as long as the TPFS and TC are both divided by the same number of generators (equal denominators for TPFS/units and TC/units).

Table 5-1. Maximum Estimates For Heat Rate Improvements and Capital Costs

	Affected Quartiles				Special Condition	Heat Rate Improvement (Btu/kWh)			Capital Cost (2014 millions of dollars)			Notes
	Q1	Q2	Q3	Q4		<=200 MW	<=500 MW	>500 MW	<=200 MW	<=500 MW	>500 MW	
Boiler Island												
Redesign and replace economizer				●	limited applicability, very site-specific	60	40	20	3.3	5.5	8.8	**HRI Reference:** ASME Energy Forum Sept 2014. Larger opportunity for economizer based efficiency improvement on smaller, older units which demonstrated higher heat rate. HRI based on engineering judgment for reasonable gains based on 24°F reduction in exit gas temperature for <200 MW; 16°F <500 MW; 10°F >500 MW. **Cost Reference:** S&L Report
Fuel Delivery System (FDS) Upgrades			●	●		84	84	84	7	12	15	**HRI Reference:** ASME Energy Forum Sept 2014. HRI from boiler efficiency gain from reduced excess air, plus auxiliary power reduction. **Cost Reference:** Leidos Estimate
Neural network		●	●	●		50	30	30	0.55	0.83	0.83	**HRI Reference:** Engineering judgment based on project experience, information in S&L Report **Cost Reference:** S&L Report
Intelligent sootblower			●	●		70	70	70	0.33	0.55	0.55	**HRI Reference:** EPRI Report April 2014 **Cost Reference:** S&L Report
Digital controls				●		0	0	0	2.2	3.80	4.40	For FDS, neural network, intelligent sootblower, performance monitoring (including feedwater heater monitoring), routine testing **Cost Reference:** S&L Report
Limit air heater leakage				●		8	5	5	0.55	0.77	1.32	**HRI Reference:** Engineering judgment based on fan power usage reduction. **Cost Reference:** S&L Report
Nano-coatings in boilers					future only							

	Affected Quartiles				Special Condition	Heat Rate Improvement (Btu/kWh)			Capital Cost (2014 millions of dollars)			Notes
	Q1	Q2	Q3	Q4		<=200 MW	<=500 MW	>500 MW	<=200 MW	<=500 MW	>500 MW	
Blowdown recovery tank				•		1	1	1	0.1	0.1	0.1	**HRI Reference:** Engineering judgment based on project experience **Cost Reference:** Leidos Estimate
Coal switching				•	future only; switching from low sulfur to higher sulfur coal unlikely/problematic							
Coal drying	•	•	•	•	future only; currently limited to mine mouth application							
Coal processing (additives)					future only							
Air heater baskets			•	•		5	5	5	0.23	0.39	0.45	**HRI Reference:** Engineering judgment based on project experience **Cost Reference:** Leidos Estimate
Lower air heater outlet temperature by controlling acid dew point		•	•	•	No FGD. This is a very site-specific issue, difficult to estimate across a wide range.	5	5	5	3.85	11	19.8	**HRI Reference:** Engineering judgment based on project experience; see special condition note. **Cost Reference:** S&L Report
Turbine Island												
Blade path upgrade			•	•	No NSR triggered	200	300	300	13.2	22	27.5	**HRI Reference:** values based on S&L report. Blade path upgrade for <200MW steam turbine units discounted because these units are in a population class with lower pressure cycles and have smaller opportunity for heat rate improvement. **Cost Reference:** S&L Report

	Affected Quartiles				Special Condition	Heat Rate Improvement (Btu/kWh)			Capital Cost (2014 millions of dollars)			Notes
	Q1	Q2	Q3	Q4		<=200 MW	<=500 MW	>500 MW	<=200 MW	<=500 MW	>500 MW	
Turbine overhaul (not including blade path upgrade)				●	part of normal maintenance	0	0	0	0	0	0	Steam turbine performance degrades over time, increasing heat rate. Maintenance is done on 7 to 10 year cycles to regain lost heat rate, but does not provide a net gain.
Condenser cleaning				●	Part of normal maintenance	0	0	0	0	0	0	Part of normal maintenance – does not result in net HRI
Boiler feed pumps				●		50	50	50	0.39	0.66	0.88	**HRI Reference:** S&L Report **Cost Reference:** S&L Report
Variable-speed drives for main cycle and auxiliary equipment			●	●		50	50	50	4	6	8	**HRI Reference:** Engineering judgment based on project experience **Cost Reference:** Leidos Estimate
Cooling system optimization			●	●		50	50	50	0.2	0.35	0.5	**HRI Reference:** Engineering judgment based on review of various sources (S&L, EPRI) **Cost Reference:** Leidos Estimate
Exhaust hood steam guide modification	●	●	●	●		2	2	2	0.3	0.3	0.3	**HRI Reference:** Engineering judgment based on project experience **Cost Reference:** Leidos Estimate
Rewind generator				●		30	40	40	4	5.5	7	**HRI Reference:** Engineering judgment based on project experience **Cost Reference:** Leidos Estimate
Topping cycle addition		●	●	●	future only							
Bottoming cycle with organic solvent		●	●	●	future only							
Flue Gas System												
ID Axial Fan (and motor) upgrades		●	●	●		80	80	80	7.7	12.1	17.6	**HRI Reference:** Engineering judgment based on project experience and information in S&L report **Cost Reference:** S&L Report

	Affected Quartiles				Special Condition	Heat Rate Improvement (Btu/kWh)			Capital Cost (2014 millions of dollars)			Notes
	Q1	Q2	Q3	Q4		<=200 MW	<=500 MW	>500 MW	<=200 MW	<=500 MW	>500 MW	
Variable-Frequency Drives			•	•		70	70	70	2.2	4.4	6.6	**HRI Reference:** Engineering judgment based on project experience and information in S&L report **Cost Reference:** S&L Report
Variable-Frequency Drives and new centrifugal fans			•	•		150	150	150	7.15	12.1	17.6	**HRI Reference:** S&L Report **Cost Reference:** S&L Report
Air Pollution Control												
Removal of Venturi throat				•		13	13	13	2.75	2.75	2.75	**HRI Reference:** S&L Report **Cost Reference:** S&L Report
Turning vanes and perforated gas distribution plates at the inlet				•		2	2	2	0.275	0.275	0.275	**HRI Reference:** S&L Report **Cost Reference:** S&L Report
Shutoff spray level				•		16	16	16	0	0	0	**HRI Reference:** S&L Report **Cost Reference:** S&L Report
Variable-Frequency Drives				•		50	50	50	1.1	3.3	5.5	**HRI Reference:** S&L Report **Cost Reference:** S&L Report
ESP Modification			•	•		5	5	5	0.22	0.55	0.88	**HRI Reference:** S&L Report **Cost Reference:** S&L Report
SCR Modification				•		10	10	10	0.55	1.1	2.2	**HRI Reference:** S&L Report **Cost Reference:** S&L Report
Water Treatment												
Cooling Tower Advanced Packing Upgrade			•	•		70	70	70	1.65	3.3	5.5	**HRI Reference:** S&L Report **Cost Reference:** S&L Report

	Affected Quartiles				Special Condition	Heat Rate Improvement (Btu/kWh)			Capital Cost (2014 millions of dollars)			Notes
	Q1	Q2	Q3	Q4		<=200 MW	<=500 MW	>500 MW	<=200 MW	<=500 MW	>500 MW	
Supplemental cooling tower		●	●	●	This is a very site-specific issue, difficult to estimate across a wide range.	10	10	10	2	3	4	**HRI Reference:** Engineering judgment based on project experience **Cost Reference:** Leidos Estimate
Other												
HR awareness training, make HR information available				●	Requires upgraded control system	150	150	150				**HRI Reference:** EPRI Report April 2014 **Cost Reference:** Leidos Estimate
Initiating routine testing programs				●		200	200	200	0.1	0.1	0.1	**HRI Reference:** EPRI Report April 2014 **Cost Reference:** Leidos Estimate
Feedwater Heater Monitoring				●	Requires upgraded control system	60	60	60				**HRI Reference:** EPRI Report April 2014 **Cost Reference:** Leidos Estimate

Table 5-2. Minimum Estimates for Heat Rate Improvements and Capital Costs

	Affected Quartiles				Special Condition	Heat Rate Improvement (Btu/kWh)			Capital Cost (2014 $M)			Notes
	Q1	Q2	Q3	Q4		<=200 MW	<=500 MW	>500 MW	<=200 MW	<=500 MW	>500 MW	
Boiler Island												
Redesign and replace economizer				●	limited applicability, very site-specific	20	20	10	2.5	3.5	5	**HRI Reference:** ASME Energy Forum Sept 2014. Larger opportunity for economizer based efficiency improvement on smaller, older units which demonstrated higher heat rate. HRI based on engineering judgment for reasonable gains based on 24°F reduction in exit gas temperature for <200 MW; 16°F <500 MW; 10°F >500 MW. **Cost Reference:** Leidos Estimate
Fuel Delivery System (FDS) Upgrades			●	●		30	30	30	3.5	6	7.5	**HRI Reference:** ASME Energy Forum Sept 2014. HRI from boiler efficiency gain from reduced excess air, plus auxiliary power reduction. **Cost Reference:** Leidos Estimate
Neural network		●	●	●		10	10	10	0.55	0.83	0.83	**HRI Reference:** Engineering judgment based on project experience, information in S&L Report **Cost Reference:** S&L Report
Intelligent sootblower			●	●		20	20	20	0.33	0.55	0.55	**HRI Reference:** EPRI Report April 2014 **Cost Reference:** S&L Report
Digital controls				●		0	0	0	2.2	3.80	4.40	For FDS, neural network, intelligent sootblower, performance monitoring (including feedwater heater monitoring), routine testing **Cost Reference:** Leidos Estimate
Limit air heater leakage				●		8	5	5	0.55	0.77	1.32	**HRI Reference:** Engineering judgment based on fan power usage reduction. **Cost Reference:** S&L Report
Nano-coatings in boilers					future only							
Blowdown recovery tank				●		1	1	1	0.1	0.1	0.1	**HRI Reference:** Engineering judgment based on project experience **Cost Reference:** Leidos Estimate

	Affected Quartiles				Special Condition	Heat Rate Improvement (Btu/kWh)			Capital Cost (2014 $M)			Notes
	Q1	Q2	Q3	Q4		<=200 MW	<=500 MW	>500 MW	<=200 MW	<=500 MW	>500 MW	
Coal switching				•	future only; switching from low sulfur to higher sulfur coal unlikely/problematic							
Coal drying	•	•	•	•	future only; currently limited to mine mouth application							
Coal processing (additives)					future only							
Air heater baskets			•	•		5	5	5	0.23	0.39	0.45	**HRI Reference:** Engineering judgment based on project experience **Cost Reference:** Leidos Estimate
Lower air heater outlet temperature by controlling acid dew point		•	•	•	No FGD. This is a very site specific issue, difficult to estimate across a wide range.	5	5	5	3.85	11	19.8	**HRI Reference:** Engineering judgment based on project experience; see special condition note. **Cost Reference:** S&L Report
Turbine Island												
Blade path upgrade			•	•	No NSR triggered	100	150	150	6	11	14	**HRI Reference:** values based on S&L report. Blade path upgrade for <200MW steam turbine units discounted because these units are in a population class with lower pressure cycles and have smaller opportunity for heat rate improvement. **Cost Reference:** S&L Report
Turbine overhaul (not including blade path upgrade)				•	part of normal maintenance	0	0	0	0	0	0	Steam turbine performance degrades over time, increasing heat rate. Maintenance is done on 7 to 10 year cycles to regain lost heat rate, but does not provide a net gain.

	Affected Quartiles				Special Condition	Heat Rate Improvement (Btu/kWh)			Capital Cost (2014 $M)			Notes
	Q1	Q2	Q3	Q4		<=200 MW	<=500 MW	>500 MW	<=200 MW	<=500 MW	>500 MW	
Condenser cleaning				●		0	0	0	0	0	0	Part of normal maintenance – does not result in net HRI
Boiler feed pumps				●		20	20	20	0.3	0.5	0.8	**HRI Reference:** Engineering judgment, S&L Report **Cost Reference:** S&L Report
Variable-speed drives for main cycle and auxiliary equipment			●	●		20	20	20	2	3	4	**HRI Reference:** Engineering judgment based on project experience **Cost Reference:** Leidos Estimate
Cooling system optimization			●	●		25	25	25	0.15	0.3	0.4	**HRI Reference:** Engineering judgment based on review of various sources (S&L, EPRI) **Cost Reference:** Leidos Estimate
Exhaust hood steam guide modification	●	●	●	●		2	2	2	0.3	0.3	0.3	**HRI Reference:** Engineering judgment based on project experience **Cost Reference:** Leidos Estimate
Rewind generator				●		30	40	40	4	5.5	7	**HRI Reference:** Engineering judgment based on project experience **Cost Reference:** Leidos Estimate
Topping cycle addition		●	●	●	future only							
Bottoming cycle with organic solvent		●	●	●	future only							
Flue Gas System												
ID Axial Fan (and motor) upgrades		●	●	●		10	10	10	5	10	12	**HRI Reference:** S&L Report **Cost Reference:** S&L Report
Variable-Frequency Drives			●	●		30	30	30	2	4	6	**HRI Reference:** Engineering judgment based on project experience and information in S&L report **Cost Reference:** S&L Report
Variable-Frequency Drives and new centrifugal fans			●	●		60	60	60	5	8	14	**HRI Reference:** Engineering judgment based on project experience and information in S&L report **Cost Reference:** Leidos Estimate
Air Pollution Control												
Removal of Venturi throat				●		7	7	7	1.4	1.4	1.4	**HRI Reference:** S&L Report **Cost Reference:** S&L Report

	Affected Quartiles				Special Condition	Heat Rate Improvement (Btu/kWh)			Capital Cost (2014 $M)			Notes
	Q1	Q2	Q3	Q4		<=200 MW	<=500 MW	>500 MW	<=200 MW	<=500 MW	>500 MW	
Turning vanes and perforated gas distribution plates at the inlet				•		1	1	1	0.275	0.275	0.275	**HRI Reference:** S&L Report **Cost Reference:** S&L Report
Shutoff spray level				•		0	0	0	0	0	0	**HRI Reference:** S&L Report **Cost Reference:** S&L Report
Variable-Frequency Drives				•		20	20	20	1.1	3.3	5.5	**HRI Reference:** S&L Report **Cost Reference:** S&L Report
ESP Modification			•	•		2	2	2	0.22	0.55	0.88	**HRI Reference:** S&L Report **Cost Reference:** S&L Report
SCR Modification				•		5	5	5	0.55	1.1	2.2	**HRI Reference:** S&L Report **Cost Reference:** S&L Report
Water Treatment												
Cooling Tower Advanced Packing Upgrade			•	•		0	0	0	1.65	3.3	5.5	**HRI Reference:** S&L Report **Cost Reference:** S&L Report
Supplemental cooling tower		•	•	•	This is a very site specific issue, difficult to estimate across a wide range.	10	10	10	2	3	4	**HRI Reference:** Engineering judgment based on project experience **Cost Reference:** Leidos Estimate
Other												
HR awareness training, make HR information available				•	requires upgraded control system	50	50	50				**HRI Reference:** EPRI Report April 2014 **Cost Reference:** Leidos Estimate
Initiating routine testing programs				•		75	75	75	0.1	0.1	0.1	**HRI Reference:** EPRI Report April 2014 **Cost Reference:** Leidos Estimate
Feedwater Heater Monitoring				•	requires upgraded control system	30	30	30				**HRI Reference:** EPRI Report April 2014 **Cost Reference:** Leidos Estimate

Table 5-3. Fixed and Variable O&M Cost Estimates for Heat Rate Improvements

	Affected Quartiles				Special Condition	Fixed O&M Costs (2014 $/yr)			Variable O&M Costs (2014 $M)			Notes
	Q1	Q2	Q3	Q4		<=200 MW	<=500 MW	>500 MW	<=200 MW	<=500 MW	>500 MW	
Boiler Island												
Redesign and replace economizer				•	limited applicability, very site-specific	55,000	110,000	165,000	0	0	0	**Cost Reference:** S&L Report
Fuel Delivery System (FDS) Upgrades			•	•								**Cost Reference:** ASME Energy Forum Sept 2014.
Neural network		•	•	•		55,000	55,000	55,000	0	0	0	**Cost Reference:** S&L Report
Intelligent sootblower			•	•		55,000	55,000	55,000	0	0	0	**Cost Reference:** S&L Report
Digital controls				•		100,000	100,000	100,000	0	0	0	**Cost Reference:** Leidos Estimate
Limit air heater leakage				•		55,000	82,500	110,000	0	0	0	**Cost Reference:** S&L Report
Nano-coatings in boilers					future only							
Blowdown recovery tank				•		0	0	0	0	0	0	**Cost Reference:** Leidos Estimate
Coal switching				•	future only; switching from low sulfur to higher sulfur coal unlikely/problematic							
Coal drying	•	•	•	•	future only; currently limited to mine mouth application							
Coal processing (additives)					future only							
Air heater baskets			•	•		20,000	30,000	40,000	0	0	0	**Cost Reference:** Leidos Estimate

	Affected Quartiles				Special Condition	Fixed O&M Costs (2014 $/yr)			Variable O&M Costs (2014 $M)			Notes
	Q1	Q2	Q3	Q4		<=200 MW	<=500 MW	>500 MW	<=200 MW	<=500 MW	>500 MW	
Lower air heater outlet temperature by controlling acid dew point		●	●	●	No FGD. This is a very site specific issue, difficult to estimate across a wide range.	55,000	82,500	110,000	385,000	935,000	1,650,000	**Cost Reference:** S&L Report
Turbine Island												
Blade path upgrade			●	●	No NSR triggered	0	0	0	0	0	0	**Cost Reference:** S&L Report
Turbine overhaul (not including blade path upgrade)				●	part of normal maintenance	0	0	0	0	0	0	**Cost Reference:** S&L Report
Condenser cleaning				●		0	0	0	0	0	0	Part of normal maintenance – does not result in net HRI
Boiler feed pumps				●		0	0	0	0	0	0	**Cost Reference:** S&L Report
Variable-speed drives for main cycle and auxiliary equipment			●	●		55,000	110,000	165,000	0	0	0	**Cost Reference:** Leidos Estimate
Cooling system optimization			●	●		55,000	110,000	165,000	0	0	0	**Cost Reference:** Leidos Estimate
Exhaust hood steam guide modification	●	●	●	●		10000	10000	10000	0	0	0	**Cost Reference:** Leidos Estimate
Rewind generator				●		10000	10000	10000	0	0	0	**Cost Reference:** Leidos Estimate
Topping cycle addition		●	●	●	future only							
Bottoming cycle with organic solvent		●	●	●	future only							
Flue Gas System												
ID Axial Fan (and motor) upgrades		●	●	●		55,000	93,500	143,000	0	0	0	**Cost Reference:** S&L Report
Variable-Frequency Drives			●	●		22,000	33,000	55,000	0	0	0	**Cost Reference:** S&L Report

	Affected Quartiles				Special Condition	Fixed O&M Costs (2014 $/yr)			Variable O&M Costs (2014 $M)			Notes
	Q1	Q2	Q3	Q4		<=200 MW	<=500 MW	>500 MW	<=200 MW	<=500 MW	>500 MW	
Variable-Frequency Drives and new centrifugal fans			●	●		27,500	41,800	66,000	0	0	0	**Cost Reference:** S&L Report
Air Pollution Control												
Removal of Venturi throat				●		0	0	0	0	0	0	**Cost Reference:** S&L Report
Turning vanes and perforated gas distribution plates at the inlet				●		0	0	0	0	0	0	**Cost Reference:** S&L Report
Shutoff spray level				●		0	0	0	0	0	0	**Cost Reference:** S&L Report
Variable-Frequency Drives				●		55,000	110,000	165,000	0	0	0	**Cost Reference:** S&L Report
ESP Modification			●	●		27,500	27,500	27,500	0	0	0	**Cost Reference:** S&L Report
SCR Modification				●		27,500	55,000	110,000	27,500	66,000	110,000	**Cost Reference:** S&L Report
Water Treatment												
Cooling Tower Advanced Packing Upgrade			●	●		82,500	137,500	192,500	0	0	0	**Cost Reference:** S&L Report
Supplemental cooling tower		●	●	●	This is a very site specific issue, difficult to estimate across a wide range.	82,500	137,500	192,500	0	0	0	**Cost Reference:** S&L Report
Other												
HR awareness training, make HR information available				●	requires upgraded control system	100,000	100,000	100,000				**Cost Reference:** Leidos Estimate
Initiating routine testing programs				●		100,000	100,000	100,000	-	-	-	**Cost Reference:** Leidos Estimate
Feedwater Heater Monitoring				●	requires upgraded control system							**Cost Reference:** Leidos Estimate

6 Applying Potential Heat Rate Improvements to the Entire Database

This chapter presents the results from applying the HRIs to the population of generators in the data set. The first section shares the HRIs associated with generators of different vintages, nameplate capacity, and ECP type. The second section describes the range of HRIs across the entire data set, and the third section describes the associated range in costs. The final section details some additional considerations that are warranted when working with this data set.

6.1 HRI Potentials as They Relate to Select Input Parameters

Although the data set contains many parameters, this analysis focused on differentiating the HRI potentials associated with major design considerations: online year, nameplate capacity, and ECP type.[37]

6.1.1 Online Year

Initially the online year parameter was a likely candidate for assessing potential HRIs, but operations that were later upgraded and regulatory concerns significantly affect the potential HRIs. Figure 6-1 shows the HRI potentials assigned to different units based on the online years. Units going online after 1990 generally offered the smallest HRI potentials in Figure 6-1; 70% of those units fell into Quartiles 1 and 2, so fewer HRI measures were attached to them.

Those going online in the 1970s and 1980s received earliest air pollution control technologies and have not necessarily been upgraded in their lifetimes. They also include the supercritical units, so their heat rates were competitive with other upgraded units for forty years which could explain why those units have not been retired.

6.1.2 Nameplate Capacity

A second likely candidate parameter for describing HRI potentials was the nameplate capacity. Figure 6-2 presents histograms showing how the number of potential HRIs is influenced by the nameplate capacity. The lowest bars on each graph show that some units of every size category have limited potential for HRI, but the highest two bars on each graph indicate that every generator size category has some units with high potential for HRI.

If the composition of the first bar in the graphs is compared to the joint composition in the last two bars, units with nameplate capacities under 100 MW or over 500 MW are represented similarly. However, a higher fraction of units with nameplate capacities between 200 and 500 MW have significant HRI potentials, and a lower fraction of units with nameplate capacities between 100 and 200 MW have significant HRI potentials.

[37] ECP types defined on page vii.

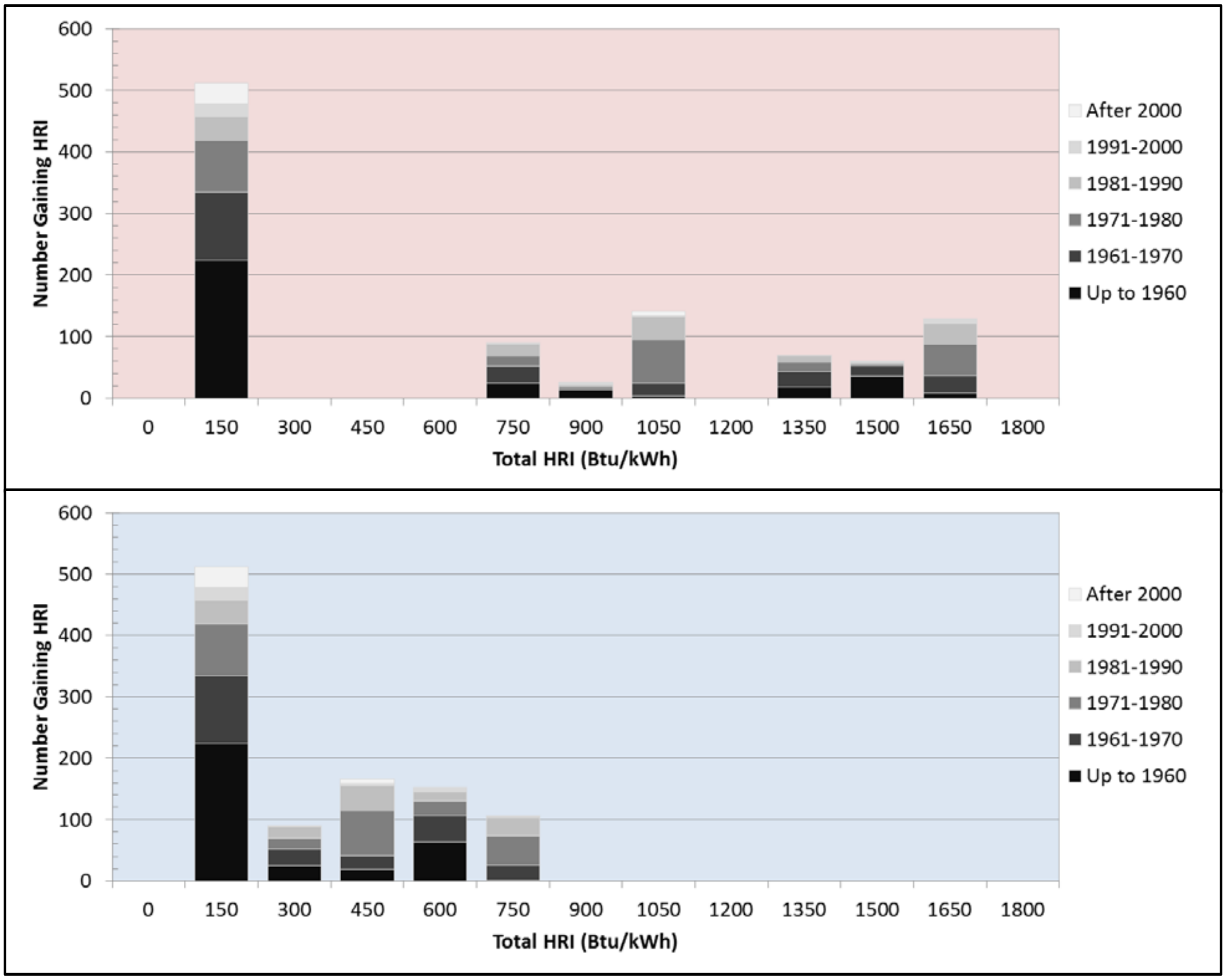


Figure 6-1. Distribution of Units with Particular HRI Potentials by Online Year (Top Representing Maxima and Bottom Representing Minima)

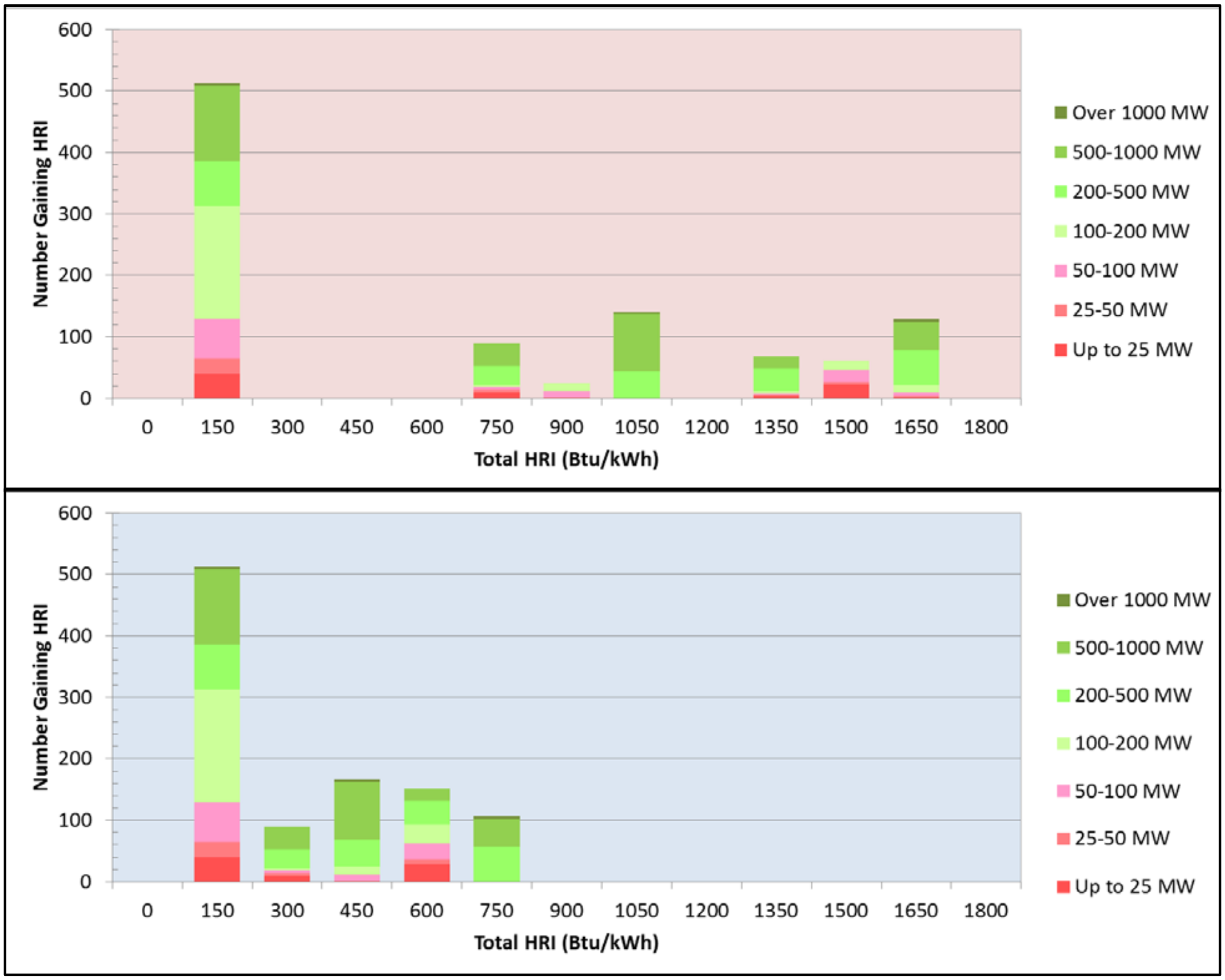


Figure 6-2. Distribution of Units with Particular HRI Potentials by Nameplate Capacity (Top Representing Maxima and Bottom Representing Minima)

6.1.3 ECP Type

Figure 6-3 illustrates how the distributions are affected by ECP type, but no trends are directly obvious from this pair of graphs. Half of the B- and C-type units (baghouse and cold-side ESP) had the maximum HRI potentials below 150 Btu/kWh, but only one third of the H-type units (Figure 6-3). Nearly 60% of the unscrubbed units (B1, C1, and H1) and dry scrubbed units (B7 and CX) had only maximum HRI potentials below 150 Btu/kWh, but only 36% of wet scrubbed units (B3, B5, C4, C7, H4, and H7) had maximum HRI potentials below 150 Btu/kWh. Only 29% of the units with SCR (B5, C7, and H7) had maximum HRI potentials below 150 Btu/kWh. From these analyses, the controls at the units with the most HRI potential are likely to be characterized by a combination of these three factors:

- wet scrubbers
- no baghouses or cold-side ESP
- SCR

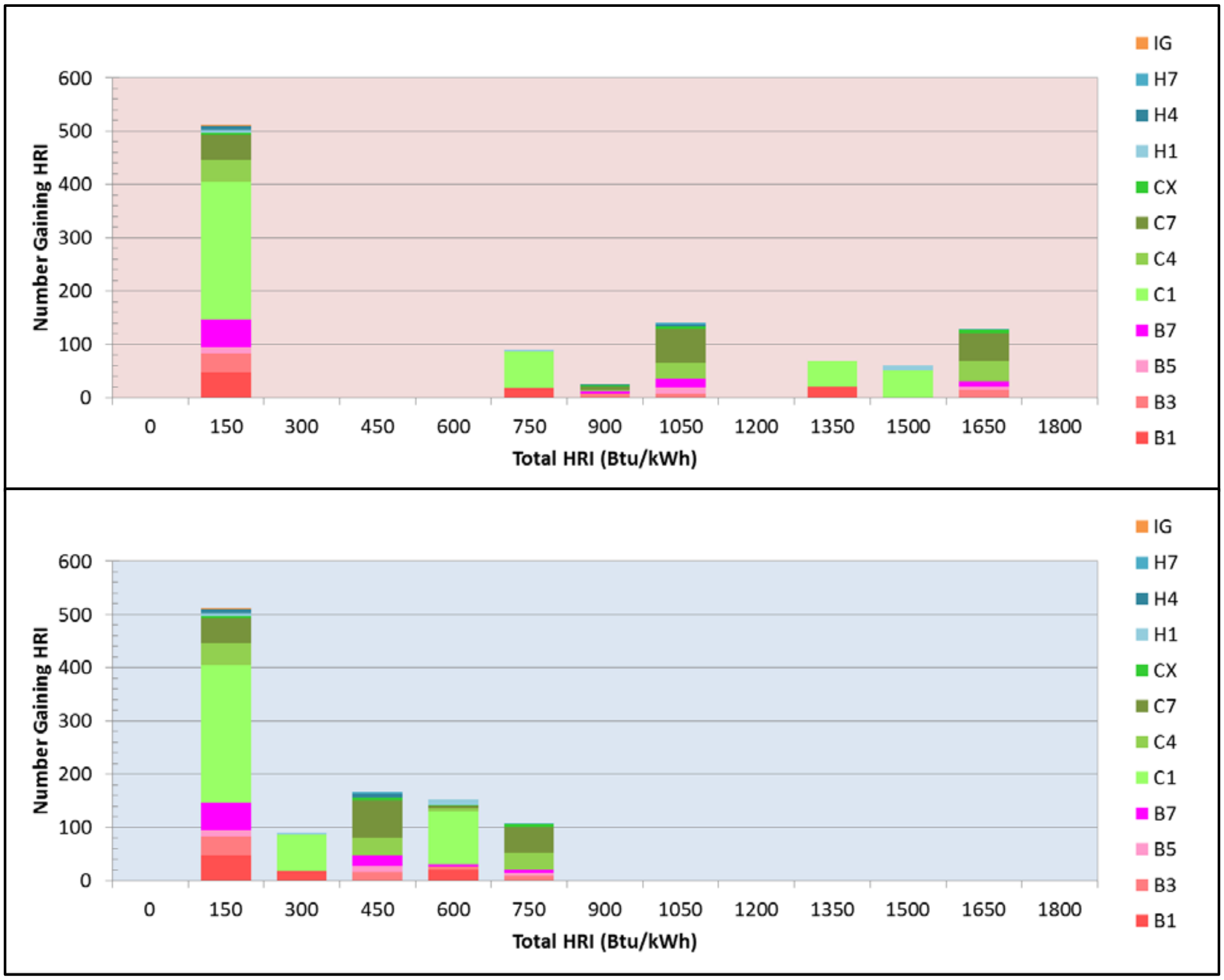


Figure 6-3. Distribution of Units with Particular HRI Potentials by ECP Type (Top Representing Maxima and Bottom Representing Minima)

Although they do not affect the statistics above significantly, the four H7 units meet this description and all had HRI potentials of 976 or 1590 Btu/kWh. The online years for the H7 units ranged from 1965 to 1977. Table 6-1 shows the ranges in HRI potentials, the average new heat rates if those were applied, and the percentage that may be gained from the HRI potential. Aside from the three IG units, the average HRI potentials range from 160-460 Btu/kWh for C1 units to 440-1130 for H7 units. The average new heat rates for the H7 units even approach those for the IG units if all of the HRIs are employed.

Table 6-1. Calculated HRI Potentials by ECP Type

ECP Code[38]	Count of Total Units	Average HRI Potential (Btu/kWh)	Average New Heat Rate (Btu/kWh)	Percent HRI Potential	Average Capital Cost ($M)	Average Fixed O&M Cost ($K/yr)	Average Variable O&M Cost ($K/yr)
B1	85	170 - 480	11,400 - 11,700	1.4% - 4.0%	32 – 40	630	640
B3	68	230 - 610	10,700 - 11,100	2.0% - 5.4%	30 – 42	590	-
B5	28	290 - 750	9,600 - 10,000	2.8% - 7.3%	45 - 64	830	19
B7	82	170 - 460	10,400 - 10,700	1.6% - 4.2%	24 – 34	450	5
C1	426	160 - 460	11,200 - 11,500	1.4% - 3.9%	29 - 35	590	58
C4	113	330 - 850	9,900 - 10,400	3.1% - 7.9%	46 – 66	900	-
C7	169	360 - 920	9,400 - 9,900	3.5% - 9.0%	56 - 79	1,100	26
CX	15	440 - 1100	10,500 - 11,200	3.7% - 9.7%	60 – 86	1,200	-
H1	21	290 - 810	15,900 - 16,400	1.7% - 4.9%	35 - 44	800	650
H4	13	210 - 560	10,500 - 10,900	1.9% - 5.1%	33 – 48	590	-
H7	4	440 - 1100	9,200 - 9,900	4.2% -11%	77 - 110	1,400	28
IG	3	2 - 2	9,200 - 9,200	0.02% - 0.02%	0.30 - 0.30	10	-
Total Set	1027	230 - 620	10,700 - 11,100	2.1% - 5.5%	36 - 49	710	320

Table 6-1 shows that the minimal percentage in HRI potential is 1.4% (ignoring the three IG units). Overall the percentage improvements for the units in the data set average 2.1% using the minimum HRI values and 5.5% using the maximum HRIs. The cost data from Table 6-1 will be discussed in Section 6.3.

Figure 6-4 also illustrates the range in HRI potentials for the various ECP types within NEMS. Aside from the IG units, the B1, B7, and C1 units have the least average HRI potential and the smallest range. The CX and H7 units have the highest HRI potentials but have a much greater range (indicating the associated uncertainty).

[38] ECP types defined on page vii.

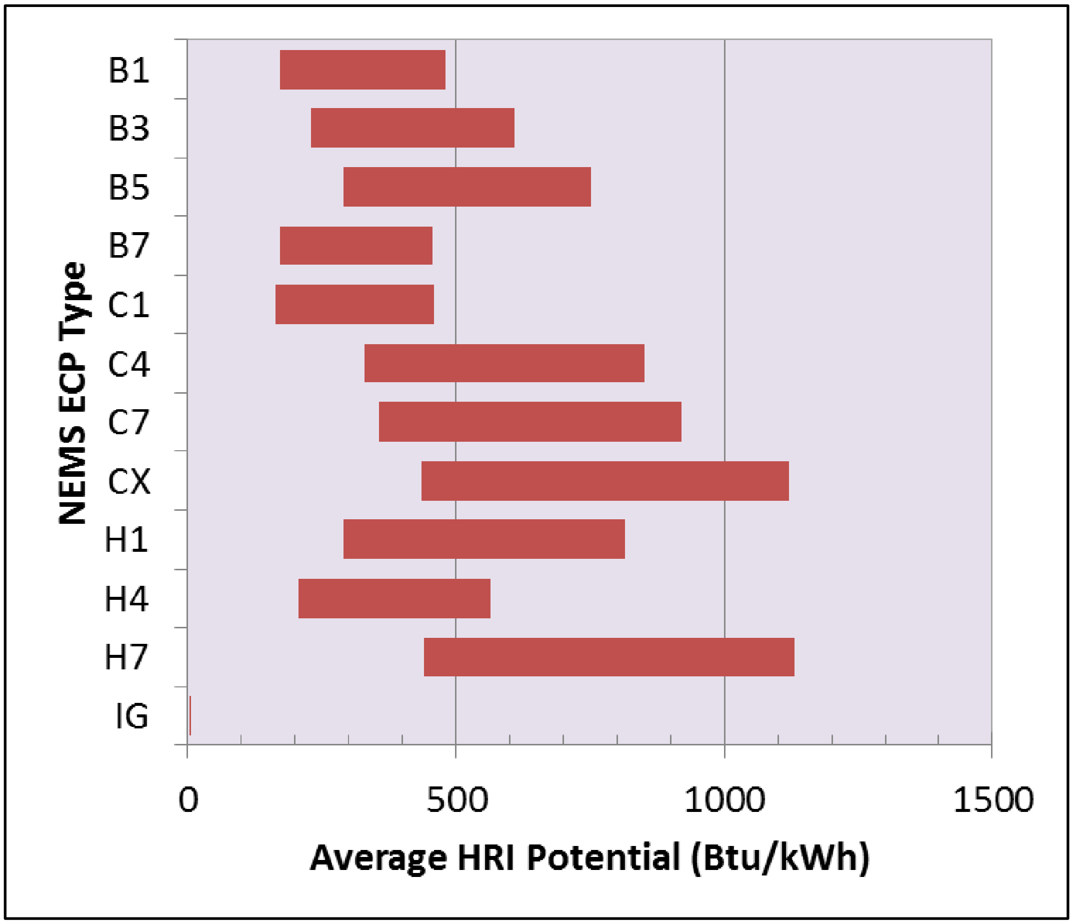


Figure 6-4. Average HRI Potentials for NEMS ECP Types (Left Side of Bar Represents Minimum HRIs and Right Side Maximum HRIs)

Figure 6-5 presents the average new heat rate that might be associated with the average unit in each ECP type. The left sides of the bars represent the average heat rates if the maximum HRI potentials are realized with every improvement, and the right sides of the bars represent the resultant heat rates when only the minimum HRIs are achieved. The plot shows that B5, C7, H7 and some C4 units might have heat rates under 10,000 Btu/kWh if the improvements are made.

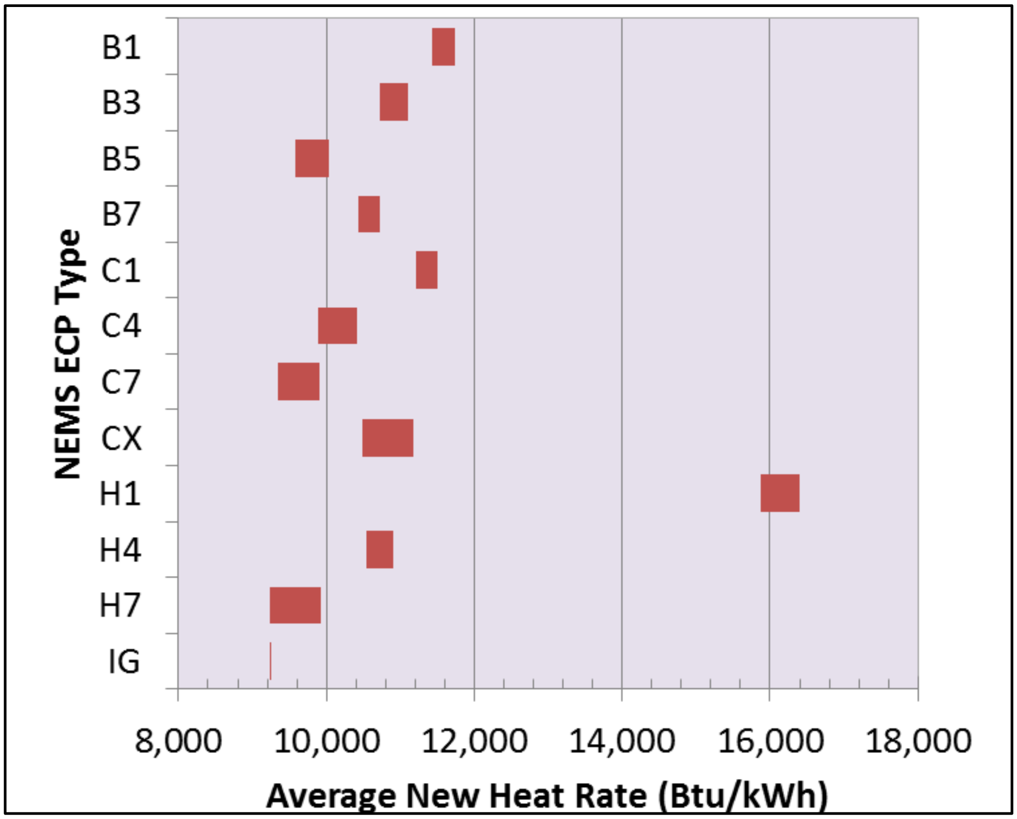


Figure 6-5. Average New Heat Rates by NEMS ECP Type

In Figure 6-5, the H1 units would continue to average high heat rates (near 16,000 Btu/kWh) even if the improvements described in Chapter 5 were all undertaken because EIA's base heat rate median and average for these 21 units are 16,000 and 16,700 Btu/kWh.

6.2 HRI for the Total Data Set

The upper graph in Figure 6-6 shows the range of total HRI potentials for all units in the data set. The blue curve represents the fraction of units that have minimum HRI potentials less than the indicated value and the red curve those with maximum HRI potentials. For example, 75% of the units have minimum HRI potentials less than 490 Btu/kWh and maximum HRI potentials under 1290 Btu/kWh with all measures employed.

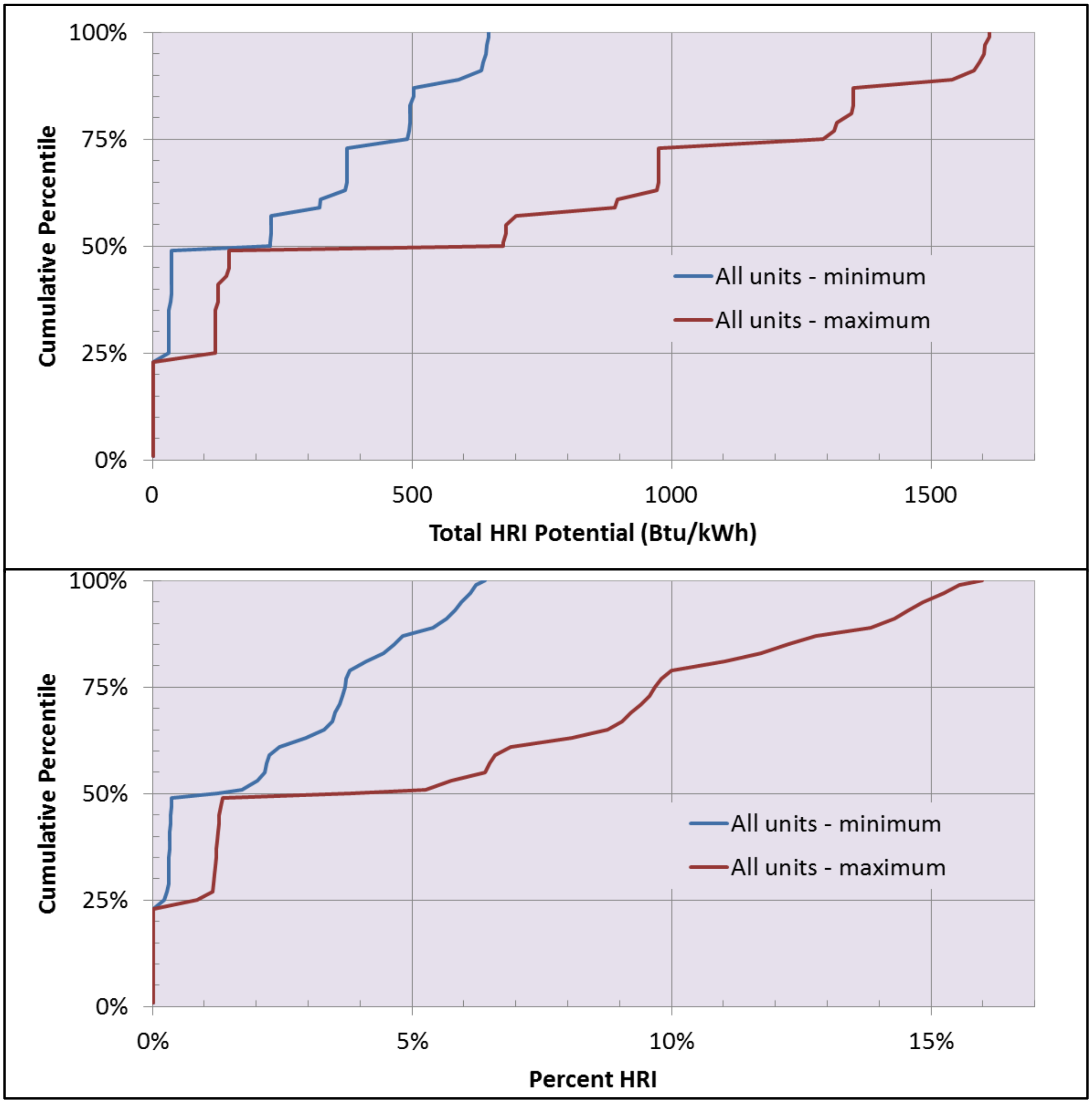


Figure 6-6. Fractions of Units with Lower Total HRI Potentials and Lower Percent HRIs

The lower graph in Figure 6-6 presents information in terms of the percent HRI potentials. The percentages above 15% in this graph represent mostly C7 units that went online between 1970 and 1982. The lower graph has a similar shape to the upper one but is smoothed out because each computed HRI potential is divided by the reported heat rate for individual units.

Table 6-2 also presents the HRI potentials in tabular form for selected benchmarks corresponding to the horizontal lines in Figure 6-6.

Table 6-2. Cumulative Percentiles for the HRI Data Sets

	HRI Potential (Btu/kWh)	Percent HRI Potential	Capital Costs ($ million)	O&M Costs ($ million per year)
25th percentile	32 - 120	0.22 - 0.87%	7.9 - 9.9	0.2
50th percentile	230 - 680	1.3 - 3.8%	29 - 41	0.5
75th percentile	490 – 1,300	3.7 - 9.7%	70 - 95	1.6
Maximum	650 – 1,600	6.4 - 16%	100 - 140	2.1
Average	230 - 620	2.0 - 5.5%	36 - 49	1.0

6.3 Associated Costs

Table 6-1 and Table 6-2 also included total cost information about the HRIs, listed by ECP type and by percentile, respectively. Aside from the IG units, Table 6-1 shows that capital costs were smallest for the 87 B7 units ($24-34 million) and highest for the four H7 units ($77-112 million). The total O&M costs were highest for the 21 H1 units ($1.45 million/year) and lowest for the B7 units ($0.46 million/year). Overall, the average capital costs were estimated between $36 and $49 million, the fixed O&M costs at $0.7 million per year and the variable O&M costs at $0.3 million per year.

Table 6-2 lists the capital and total O&M costs based on percentiles. Those values are displayed graphically in Figure 6-7. If the costs were similar between the 25th and 75th percentiles, then one might conclude that a reasonable approximation for the costs would be a median value. However, the capital costs vary from $7.9 to $95 million between the 25th and 75th percentiles and the O&M costs vary from $0.2 and $1.6 million per year. Therefore, the median values ($35 million and $0.5 million per year) are not good representations of the middle 50% of the data.

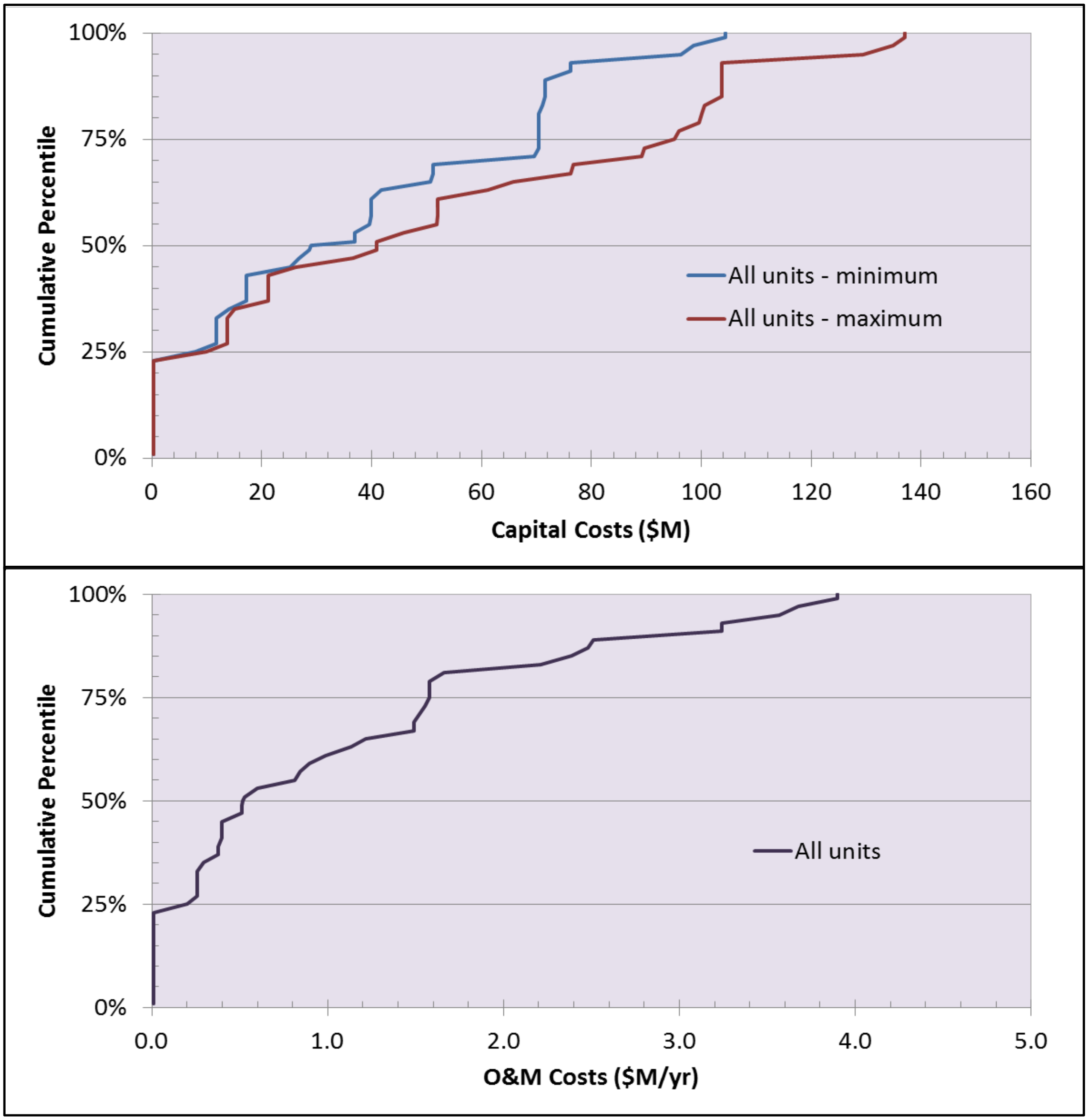
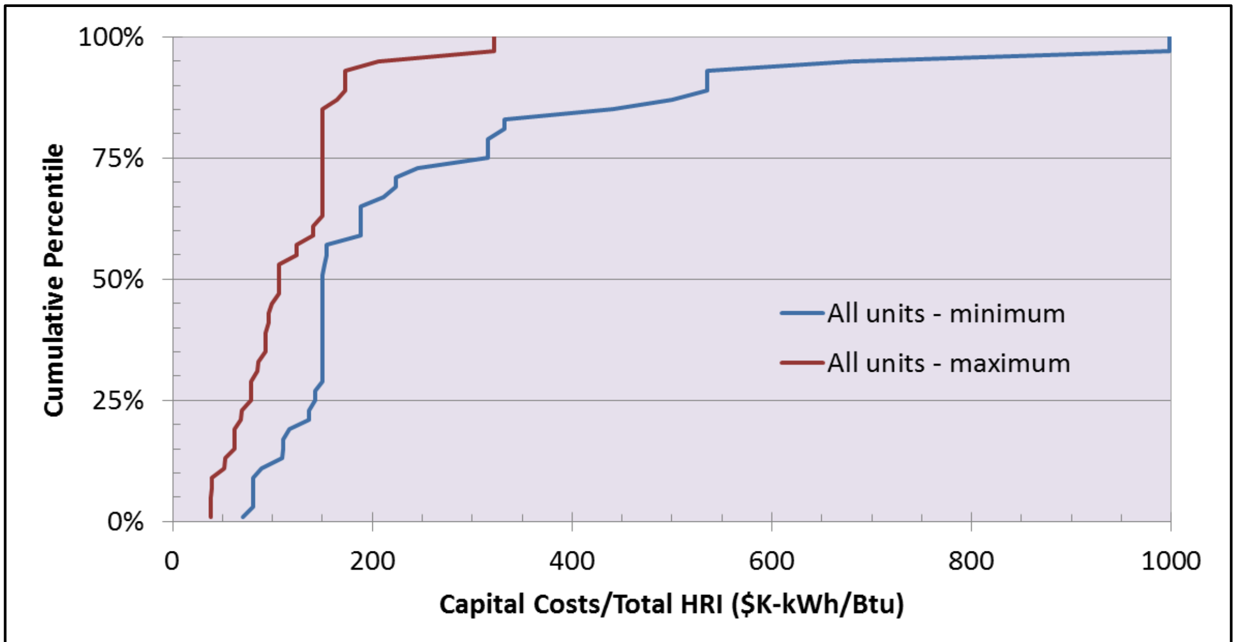


Figure 6-7. Cumulative Percentile Graphs Depicting HRI Costs at Different Units

In contrast, the first cumulative percentile graph shown in Figure 6-8 has a much tighter distribution between the 25th and 75th percentiles. The median value of \$130,000-kWh/Btu is not far from the 25th percentile value (\$110,000-kWh/Btu) or the 75th percentile value (\$230,000-kWh/Btu). However, the range for the total O&M costs divided by the HRI was still between \$3,500-kWh/Btu-yr and \$67,000-kWh/Btu-yr for the middle 50% of the data.



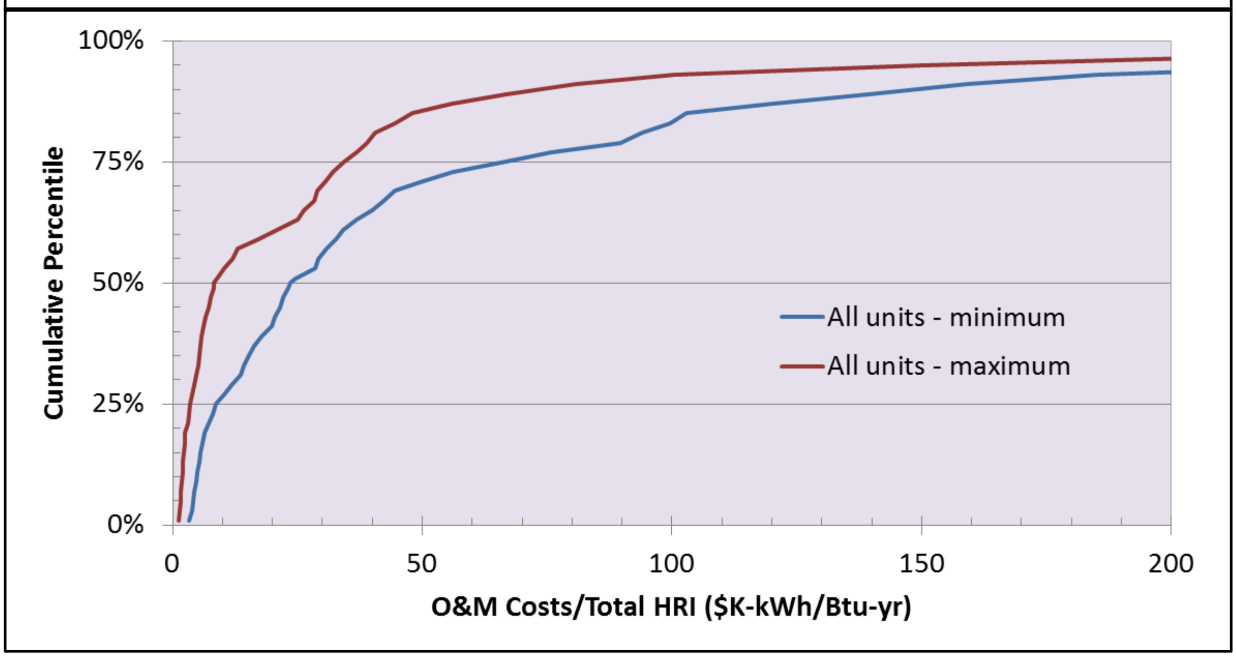


Figure 6-8. Cumulative Percentile Graphs Depicting HRI Unit Costs at Different Units

Figure 6-9 shows how the average HRI potentials for the twelve ECP types relate to the capital and total O&M costs. The capital costs can be well approximated (r^2=0.90) by multiplying the HRI potential by $100,000-kWh/Btu, and that agrees well with the median value of $130,000-kWh/Btu when all of the units were considered in Figure 6-8.

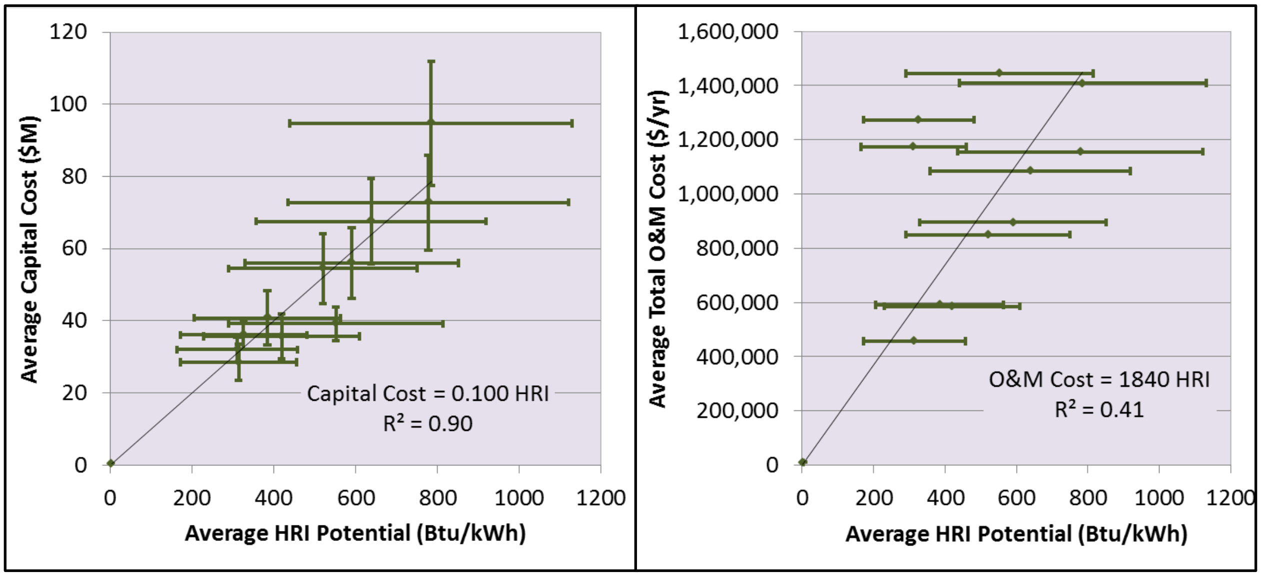


Figure 6-9. Relationship between Costs and HRI Potential for ECP Types

However, the total O&M costs are not well estimated (r^2=0.41). The poor approximations of total O&M costs are tied to the non-linearity of the variable O&M costs and one HRI measure in particular. The HRI described as "Lower air heater outlet temperature by controlling acid dew point" may be applied to units without FGD (B1, C1, and H1) but only improves the heat rate by 5 Btu/kWh at a high variable O&M cost ($390,000 to $1,700,000 per year). Variable O&M costs drop to just 2% of the total O&M costs if this one HRI measure is removed from consideration (r^2=0.95 and slope=$1600-kWh/Btu-yr).

6.4 Other Considerations

No intent to describe these improvements at site level was attempted because every plant is unique in design, load demands, coal type, and water availability, among others. Such efforts should likely examine more O&M cost variations with plant size and capacity factors.

Some additional measures could have been included in Chapter 5 but could not be assessed on a fleet-wide level. These include:

- Sliding pressure operation
- Boiler draft system control schemes and operating philosophy
- Automated pulverizer supervisory controls and variations with mill design
- Optimum partial load operation of air quality control systems
- Increasing hydrogen purity
- Power supply upgrade for air pollution controls

Some additional measures were not costed in this effort because they are still in the development phase. It may be appropriate for the NEMS EMM module to apply a generic technology-improvement factor to the HRIs for the entire fleet after a decade or two. However, the NSR triggering concerns may limit the market penetration.

Figure 6-1, Figure 6-2 and Figure 6-3 also illustrate that the distribution of HRI potentials among the units does not form a normal distribution. Half of the units have maximum HRI potentials less than 150 Btu/kWh, but the remaining half average 1160 Btu/kWh for the maximum HRI potentials. The nearest unit to the average has a maximum HRI potential of 1290 Btu/kWh. The quartile approach to fleet characterization and application of specific controls is likely responsible for some of the behavior. These data distributions suggest that users should be cautious about applying assumptions about averages to these data types. The cumulative percentile approach (Section 6.2) may yield better ranges than the use of averages as substitutions for individual units.

The S&L report was working from a fleet average heat rate of 10,400 Btu/kWh, but the EIA 2012 data had an average heat rate of 11,300 Btu/kWh. A speaker[39] at the Annual EPA-A&WMA Information Exchange suggested that the heat rates may have risen between 2008 and 2012 because more coal-fired units were now operating in cycling modes rather than using a base load. Another study mentioned that the change in heat rates was due to a change in the calculation methodology. The percent HRIs shared in Table 6-1 and Table 6-2 are based on the 2012 numbers but would have been higher in many cases if 2008 heat rates had been used. For example, if the total HRI at a typical plant was 400 Btu/kWh, this would have represented a 3.8% improvement in 2008 but only 3.5% in 2012.

[39] Licata, Anthony, "ASME Heat Rate Improvement," 39th Annual EPA-A&WMA Information Exchange, Research Triangle Park, North Carolina, December 3, 2014.

7 Recommendations

Several possible directions for future *data acquisition* or *ground truthing* are recommended:

1. A utility industry survey could be conducted to assess those heat rate improvement measures that have already been deployed at each plant in order to populate future databases.
2. Gurbakhash Bhander at U.S. EPA has been developing the GHG Mitigation Options Database (GMOD) and Analysis Tool to show the costs associated with various operations (including power sector measures such as leakage repair, boiler condenser cleaning, and intelligent sootblowers).[40] Bhander will notify Leidos when EPA management has approved the tool for release, and its numbers would need to be converted from lbs CO_2/Btu to kWh/Btu before comparing to those values represented in this report.
3. Public comments about EPA's proposed power plant rules and the Clean Power Plan likely contain a significant amount of technical data from the utility companies and the states about the HRI potential at each of their power plants. These data sources represent direct assessments by some rule stakeholders and likely will represent at least minimum HRIs and maximum estimated costs. When available, review of this information is recommended.
4. Review of the literature for this project has identified the subject of increased coal-fired plant cycling operation as an important impact on future performance. While most of the U.S. coal-fired plants were generally designed for base-load operation, the increased use of intermittent electricity generation, and gas-fired units fed by relatively inexpensive natural gas, has altered actual generation conditions such that many of these units now operate in a continuous load-following mode to match the generation demand. Therefore, these units frequently operate with large load changes throughout the day and week. This newer mode of cycling operation for the aging inventory of coal-fired units will result in increased plant heat rate (decreased efficiency), even though the actual average capacity factor of these units may not change appreciably. This was out of scope for this study, but we recommend that EIA further investigate this phenomenon to account for the future modeled heat rate performance of the coal-fired plants.
5. Preliminary costing could be sought for the technologies that are still considered in the R&D or pilot phase (e.g., nano-coatings on boiler walls that prevent heat degradation). Such options would only be available within NEMS in later years. Literature works and patents indicate that some degree of success is being made in these areas, but often readers would find it difficult to classify the HRIs in these pilot studies as maxima or minima. The public literature on these studies generally does not cite costs, so full cost evaluations would be necessary for EIA to establish ranges on the capital, operating, and maintenance costs across all potential plants.

[40] Bhander, G., N. Hutson, J. Rosati, F. Princiotta, K. Pelt, J. Staudt, and J. Petrusa, "GHG Mitigation Options Database (GMOD) and Analysis Tool," *International Journal of Greenhouse Gas Control*, 26, 2014, 1-8.

6. Minima and maxima were used to bound the resultant HRI potentials and costs shared in this report. However, those values could be viewed as 95th percentile limits two standard deviations from an average. A Monte Carlo simulation that allows random selection of individual HRI potentials and costs from among each range would likely result in smoother distribution curves than those shown in Chapter 6 and would result in best guesses for many HRI measures, not just the minimum and maximum values.

The NEMS modeling of HRI changes may also look toward new possibilities:

1. Upgrade the ECP type if a plant triggers NSR, and consider adding these costs as a condition associated with the HRI.
2. Allow an assortment of *HRI packages* to be applied at a unit instead of just a single total HRI and associated total cost. These might be scoped out as boiler island, turbine island, flue gas, air pollution control, and water treatment improvement packages. However, this approach might require five flags associated with units to indicate where HRIs had already been made. A second approach would be to have HRI packages assembled for different geographic areas based on local climates (e.g., water cooling issues) and/or regulations (e.g., acid rain programs).

Appendix A. Heat Rate Improvements Assigned to ECP Types[41]

ECP Code	Count of Total Units	Average HRI Potential (Btu/kWh)	Average New Heat Rate (Btu/kWh)	Percent HRI Potential	Average Capital Cost ($M)	Average Fixed O&M Cost ($K/yr)	Average Variable O&M Cost ($K/yr)	Average Capital Cost ($M/MW NPC)	Average Fixed O&M Cost ($/yr-MW NPC)	Average Variable O&M Cost ($/yr-MW NPC)
B1	85	170 - 480	11,000 - 12,000	1.4% - 4.0%	32 - 40	630	330 - 640	0.24 - 0.31	6,000	1,700 - 3,300
B3	68	230 - 610	11,000	2.0% - 5.4%	30 - 42	590	0	0.17 - 0.25	3,800	0
B5	28	290 - 750	10,000	2.8% - 7.3%	45 - 64	830	19	0.087 - 0.13	1,600	36
B7	82	170 - 460	10,000 - 11,000	1.6% - 4.2%	23 - 34	450	5	0.11 - 0.16	2,200	36
C1	426	160 - 460	11,000 - 12,000	1.4% - 3.9%	29 - 35	590	300 - 590	0.27 - 0.35	6,900	2,000 - 4,000
C4	113	330 - 850	10,000	3.1% - 7.9%	46 - 66	900	0	0.12 - 0.17	2,500	0
C7	169	360 - 920	9,400 - 10,000	3.5% - 9.0%	56 - 79	1,100	26	0.11 - 0.15	2,100	55
CX	15	440 - 1,100	10,000 - 11,000	3.7% - 9.7%	60 - 86	1,200	0	0.19 - 0.28	3,900	0
H1	21	290 - 810	16,000	1.7% - 4.9%	35 - 44	800	330 - 650	2.3 - 3.0	63,000	14,000 - 26,000
H4	13	210 - 560	11,000	1.9% - 5.1%	33 - 48	590	0	0.14 - 0.21	2,600	0
H7	4	440 - 1,100	9,200 - 10,000	4.2% - 11%	77 - 110	1,400	28	0.12 - 0.17	2,100	50
IG	3	2	9,200	0.02%	0.3	10	0	0.002	64	0
Total Set	**1027**	**230 - 620**	**11,000**	**2.1% - 5.5%**	**36 - 49**	**710**	**160 - 320**	**0.24 - 0.32**	**5,800**	**1,300 - 2,500**

[41] ECP types defined on page vii.

Appendix B. Heat Rate Improvements Assigned to Modified ECP Types (Allowing ECP Types to be Categorized by Quartile and Assuring at Least 10 Records in Each Non-IG Group)

ECP Code	Count of Total Units	Average HRI Potential (Btu/kWh)	Average New Heat Rate (Btu/kWh)	Percent HRI Potential	Average Capital Cost ($M)	Average Fixed O&M Cost ($K/yr)	Average Variable O&M Cost ($K/yr)	Average Capital Cost ($M/MW NPC)	Average Fixed O&M Cost ($/yr-MW NPC)	Average Variable O&M Cost ($/yr-MW NPC)
B1-Q1	32	2	12,000	0.0%	0.3	10	0	0.007	250	0
B1-Q2	15	40 - 140	11,000	0.3% - 1.2%	22 - 24	360	430 - 870	0.096 - 0.11	1,800	1,700 - 3,400
B1-Q3	18	230 - 680	10,000	2.1% - 6.4%	66 - 84	1,100	690 - 1,400	0.20 - 0.26	3,700	1,800 - 3,500
B1-Q4	20	500 - 1,300	13,000 - 14,000	3.5% - 9.4%	60 - 76	1,400	440 - 830	0.76 - 0.99	20,000	4,500 - 8,400
B3-Q1	13	2	12,000	0.0%	0.3	10	0	0.010	330	0
B3-Q2	24	30 - 130	11,000	0.3% - 1.2%	13 - 15	290	0	0.047 - 0.056	1,100	0
B3-Q3	16	350 - 930	10,000 - 11,000	3.1% - 8.2%	44 - 68	750	0	0.19 - 0.30	3,300	0
B3-Q4	15	620 - 1,600	11,000	5.1% - 13%	65 - 93	1,400	0	0.50 - 0.72	12,000	0
B5C7-Q1	16	2	10,000	0.0%	0.3	10	0	0.003	84	0
B5C7-Q2	42	30 - 120	10,000	0.3% - 1.2%	16 - 20	380	0	0.031 - 0.036	700	0
B5C7H7-Q3	84	370 - 970	9,200 - 10,000	3.6% - 9.5%	64 - 94	1,100	0	0.11 - 0.16	1,800	0
B5C7H7-Q4	59	640 - 1,600	9,100 - 10,000	6.0% - 15%	84 - 120	1,700	86	0.18 - 0.25	3,800	180
B7-Q1	27	2	11,000	0.0%	0.3	10	0	0.002	68	0
B7-Q2	25	30 - 130	10,000	0.3% - 1.2%	15 - 17	340	0	0.035 - 0.042	820	0
B7-Q3Q4	30	440 - 1,100	10,000 - 11,000	3.8% - 9.8%	52 - 77	950	15	0.27 - 0.40	5,400	99
C1H1-Q1	148	2	11,000	0.0%	0.3	10	0	0.006	190	0
C1H1-Q2	117	40 - 140	11,000	0.3% - 1.2%	22 - 25	360	440 - 880	0.12 - 0.13	2,300	2,100 - 4,100
C1H1-Q3	72	230 - 690	11,000	2.0% - 6.0%	53 - 68	1,000	520 - 1,000	0.36 - 0.49	7,700	2,900 - 5,800
C1H1-Q4	110	500 - 1,300	13,000	3.6% - 9.6%	59 - 75	1,400	420 - 790	1.1 - 1.5	31,000	6,500 - 12,000

ECP Code	Count of Total Units	Average HRI Potential (Btu/kWh)	Average New Heat Rate (Btu/kWh)	Percent HRI Potential	Average Capital Cost ($M)	Average Fixed O&M Cost ($K/yr)	Average Variable O&M Cost ($K/yr)	Average Capital Cost ($M/MW NPC)	Average Fixed O&M Cost ($/yr-MW NPC)	Average Variable O&M Cost ($/yr-MW NPC)
C4-Q1	15	2	11,000	0.0%	0.3	10	0	0.002	80	0
C4-Q2	27	30 - 120	10,000	0.3% - 1.2%	15 - 17	330	0	0.041 - 0.048	940	0
C4-Q3	32	370 - 970	10,000	3.5% - 9.1%	62 - 92	1,000	0	0.13 - 0.20	2,300	0
C4-Q4	39	630 - 1,600	9,500 - 10,000	5.7% - 14%	73 - 100	1,500	0	0.21 - 0.30	4,600	0
CX-Q1Q2Q3Q4	15	440 - 1,100	10,000 - 11,000	3.7% - 9.7%	60 - 86	1,200	0	0.19 - 0.28	3,900	0
H4-Q1Q2Q3	13	210 - 560	11,000	1.9% - 5.1%	33 - 48	590	0	0.14 - 0.21	2,600	0
IG-Q1	3	2	9,200	0.0%	0.3	10	0	0.002	64	0
Total Set	**1027**	**230 - 620**	**11,000**	**2.0% - 5.3%**	**36 - 49**	**710**	**160 - 320**	**0.24 - 0.32**	**5,800**	**1,300 - 2,500**

Appendix C. Modified Heat Rate Improvements Assigned to ECP Types (If Lowering Air Heater Outlet Temperature Is Not Considered a Cost-Effective Measure)

ECP Code	Count of Total Units	Average HRI Potential (Btu/kWh)	Average New Heat Rate (Btu/kWh)	Percent HRI Potential	Average Capital Cost ($M)	Average Fixed O&M Cost ($K/yr)	Average Variable O&M Cost ($K/yr)	Average Capital Cost ($M/MW NPC)	Average Fixed O&M Cost ($/yr-MW NPC)	Average Variable O&M Cost ($/yr-MW NPC)
B1	85	170 - 480	11,000 - 12,000	1.4% - 4.0%	25 - 33	580	13	0.21 - 0.28	5,600	130
B3	68	230 - 610	11,000	2.0% - 5.4%	30 - 42	590	0	0.17 - 0.25	3,800	0
B5	28	290 - 750	10,000	2.8% - 7.3%	45 - 64	830	19	0.087 - 0.13	1,600	36
B7	82	170 - 460	10,000 - 11,000	1.6% - 4.2%	23 - 34	450	5	0.11 - 0.16	2,200	36
C1	426	160 - 460	11,000 - 12,000	1.4% - 3.9%	22 - 29	540	13	0.23 - 0.31	6,400	140
C4	113	330 - 850	10,000	3.1% - 7.9%	46 - 66	900	0	0.12 - 0.17	2,500	0
C7	169	360 - 920	9,400 - 10,000	3.5% - 9.0%	56 - 79	1,100	26	0.11 - 0.15	2,100	55
CX	15	440 - 1,100	10,000 - 11,000	3.7% - 9.7%	60 - 86	1,200	0	0.19 - 0.28	3,900	0
H1	21	290 - 810	16,000	1.7% - 4.9%	28 - 37	730	13	2.1 - 2.8	59,000	1,400
H4	13	210 - 560	11,000	1.9% - 5.1%	33 - 48	590	0	0.14 - 0.21	2,600	0
H7	4	440 - 1,100	9,200 - 10,000	4.2% - 11%	77 - 110	1,400	28	0.12 - 0.17	2,100	50
IG	3	2 - 2	9,200	0.02%	0.3	10	0	0.002	64	0
Total Set	**1027**	**230 - 620**	11,000	**2.1% - 5.5%**	**33 - 45**	**690**	**12**	**0.22 - 0.29**	**5,500**	**110**

Appendix D. Modified Heat Rate Improvements Assigned to Modified ECP Types (If Lowering Air Heater Outlet Temperature Is Not Considered a Cost-Effective Measure)

ECP Code	Count of Total Units	Average HRI Potential (Btu/kWh)	Average New Heat Rate (Btu/kWh)	Percent HRI Potential	Average Capital Cost ($M)	Average Fixed O&M Cost ($K/yr)	Average Variable O&M Cost ($K/yr)	Average Capital Cost ($M/MW NPC)	Average Fixed O&M Cost ($/yr-MW NPC)	Average Variable O&M Cost ($/yr-MW NPC)
B1-Q1	32	2	12,000	0.02%	0.3	10	0	0.007	250	0
B1-Q2	15	30 - 130	11,000	0.3% - 1.2%	12 - 14	280	0	0.059 - 0.071	1,400	0
B1-Q3	18	220 - 670	10,000	2.1% - 6.3%	49 - 67	1,000	0	0.16 - 0.22	3,400	0
B1-Q4	20	490 - 1,300	13,000 - 14,000	3.5% - 9.3%	51 - 68	1,300	54	0.68 - 0.91	19,000	560
B3-Q1	13	2	12,000	0.02%	0.3	10	0	0.010	330	0
B3-Q2	24	30 - 130	11,000	0.3% - 1.2%	13 - 15	290	0	0.047 - 0.056	1,100	0
B3-Q3	16	350 - 930	10,000 - 11,000	3.1% - 8.2%	44 - 68	750	0	0.19 - 0.30	3,300	0
B3-Q4	15	620 - 1,600	11,000	5.1% - 13%	65 - 93	1,400	0	0.50 - 0.72	12,000	0
B5C7-Q1	16	2	10,000	0.02%	0.3	10	0	0.003	84	0
B5C7-Q2	42	32 - 120	10,000	0.3% - 1.2%	16 - 20	380	0	0.031 - 0.036	700	0
B5C7H7-Q3	84	370 - 970	9,200 - 10,000	3.6% - 9.5%	64 - 94	1,100	0	0.11 - 0.16	1,800	0
B5C7H7-Q4	59	640 - 1,600	9,100 - 10,000	6.0% - 15%	84 - 120	1,700	86	0.18 - 0.25	3,800	180
B7-Q1	27	2	11,000	0.02%	0.3	10	0	0.002	68	0
B7-Q2	25	32 - 130	10,000	0.3% - 1.2%	15 - 17	340	0	0.035 - 0.042	820	0
B7-Q3Q4	30	440 - 1,100	10,000 - 11,000	3.8% - 9.8%	52 - 77	950	15	0.27 - 0.40	5,400	99
C1H1-Q1	148	2	11,000	0.02%	0.3	10	0	0.006	190	0
C1H1-Q2	117	32 - 130	11,000	0.3% - 1.2%	12 - 14	280	0	0.073 - 0.090	1,800	0
C1H1-Q3	72	220 - 680	11,000	1.9% - 5.9%	41 - 56	870	0	0.30 - 0.43	7,000	0
C1H1-Q4	110	490 - 1,300	13,000	3.5% - 9.6%	50 - 66	1,300	51	1.0 - 1.4	29,000	810
C4-Q1	15	2	11,000	0.02%	0.3	10	0	0.002	80	0

ECP Code	Count of Total Units	Average HRI Potential (Btu/kWh)	Average New Heat Rate (Btu/kWh)	Percent HRI Potential	Average Capital Cost ($M)	Average Fixed O&M Cost ($K/yr)	Average Variable O&M Cost ($K/yr)	Average Capital Cost ($M/MW NPC)	Average Fixed O&M Cost ($/yr-MW NPC)	Average Variable O&M Cost ($/yr-MW NPC)
C4-Q2	27	32 - 120	10,000	0.3% - 1.2%	15 - 17	330	0	0.041 - 0.048	940	0
C4-Q3	32	370 - 970	10,000	3.5% - 9.1%	62 - 92	1,000	0	0.13 - 0.20	2,300	0
C4-Q4	39	630 - 1,600	9,500 - 10,000	5.7% - 14%	73 - 100	1,500	0	0.21 - 0.30	4,600	0
CX-Q1Q2Q3Q4	15	440 - 1,100	10,000 - 11,000	3.7% - 9.7%	60 - 86	1,200	0	0.19 - 0.28	3,900	0
H4-Q1Q2Q3	13	210 - 560	11,000	1.9% - 5.1%	33 - 48	590	0	0.14 - 0.21	2,600	0
IG-Q1	3	2	9,200	0.02%	0.3	10	0	0.002	64	0
Total Set	**1027**	**230 - 620**	**11,000**	**2.0% - 5.3%**	**33 - 45**	**690**	**12**	**0.22 - 0.29**	**5,500**	**110**

Appendix E. Midpoints between Minima and Maxima in Appendix A*

ECP Code	Count of Total Units	HRI Potential (Btu/kWh)	New Heat Rate (Btu/kWh)	Percent HRI Potential	Capital Cost ($M)	Fixed O&M Cost ($K/yr)	Variable O&M Cost ($K/yr)	Capital Cost ($M/MW NPC)	Average Fixed O&M Cost ($/yr-MW NPC)	Average Variable O&M Cost ($/yr-MW NPC)
B1	85	300	12,000	3%	40	600	500	0.30	6000	3000
B3	68	400	11,000	4%	40	600	0	0.20	4000	0
B5	28	500	9,800	5%	50	800	20	0.10	2000	40
B7	82	300	11,000	3%	30	500	5	0.10	2000	40
C1	426	300	11,000	3%	30	600	400	0.30	7000	3000
C4	113	600	10,000	5%	60	900	0	0.10	2000	0
C7	169	600	9,600	6%	70	1,000	30	0.10	2000	60
CX	15	800	11,000	7%	70	1,000	0	0.20	4000	0
H1	21	600	16,000	3%	40	800	500	3.00	60000	20000
H4	13	400	11,000	3%	40	600	0	0.20	3000	0
H7	4	800	9,600	8%	90	1,000	30	0.10	2000	50
IG	3	2	9,200	0.0%	0	10	0	0.00	60	0
TOTAL SET	**1027**	**400**	**11,000**	**4%**	**40**	**700**	**200**	**0.30**	**6000**	**2000**

* This table presents the midpoints between the minima and maxima. Determination of actual averages would require enough full-scale plant evaluations to determine the appropriate distributions of data between the minima and maxima.

Appendix F. Midpoints between Minima and Maxima in Appendix B*

ECP Code	Count of Total Units	HRI Potential (Btu/kWh)	New Heat Rate (Btu/kWh)	Percent HRI Potential	Capital Cost ($M)	Fixed O&M Cost ($K/yr)	Variable O&M Cost ($K/yr)	Capital Cost ($M/MW NPC)	Average Fixed O&M Cost ($/yr-MW NPC)	Average Variable O&M Cost ($/yr-MW NPC)
B1-Q1	32	2	12,000	0.0%	0	10	0	0.01	200	0
B1-Q2	15	90	11,000	0.8%	20	400	700	0.10	2000	3000
B1-Q3	18	500	10,000	4%	70	1000	1000	0.20	4000	3000
B1-Q4	20	900	13,000	6%	70	1000	600	0.90	20000	6000
B3-Q1	13	2	12,000	0.0%	0	10	0	0.01	300	0
B3-Q2	24	80	11,000	0.7%	10	300	0	0.05	1000	0
B3-Q3	16	600	11,000	6%	60	700	0	0.20	3000	0
B3-Q4	15	1000	11,000	9%	80	1000	0	0.60	10000	0
B5C7-Q1	16	2	10,000	0.0%	0	10	0	0.00	80	0
B5C7-Q2	42	80	9,900	0.8%	20	400	0	0.03	700	0
B5C7H7-Q3	84	700	9,500	7%	80	1000	0	0.10	2000	0
B5C7H7-Q4	59	1000	9,500	10%	100	2000	90	0.20	4000	200
B7-Q1	27	2	11,000	0.0%	0	10	0	0.00	70	0
B7-Q2	25	80	10,000	0.8%	20	300	0	0.04	800	0
B7-Q3Q4	30	800	11,000	7%	60	900	10	0.30	5000	100
C1H1-Q1	148	2	11,000	0.0%	0	10	0	0.01	200	0
C1H1-Q2	117	90	11,000	0.8%	20	400	700	0.10	2000	3000
C1H1-Q3	72	500	11,000	4%	60	1000	800	0.40	8000	4000
C1H1-Q4	110	900	13,000	7%	70	1000	600	1.00	30000	9000
C4-Q1	15	2	11,000	0.0%	0	10	0	0.00	80	0
C4-Q2	27	80	10,000	0.8%	20	300	0	0.04	900	0
C4-Q3	32	700	10,000	6%	80	1000	0	0.20	2000	0
C4-Q4	39	1000	10,000	10%	90	2000	0	0.30	5000	0
CX-Q1Q2Q3Q4	15	800	11,000	7%	70	1000	0	0.20	4000	0

ECP Code	Count of Total Units	HRI Potential (Btu/kWh)	New Heat Rate (Btu/kWh)	Percent HRI Potential	Capital Cost ($M)	Fixed O&M Cost ($K/yr)	Variable O&M Cost ($K/yr)	Capital Cost ($M/MW NPC)	Average Fixed O&M Cost ($/yr-MW NPC)	Average Variable O&M Cost ($/yr-MW NPC)
H4-Q1Q2Q3	13	400	11,000	3%	40	600	0	0.20	3000	0
IG-Q1	3	2	9,200	0.0%	0	10	0	0.00	60	0
TOTAL SET	**1027**	**400**	**11,000**	**4%**	**40**	**700**	**200**	**0.30**	**6000**	**2000**

* This table presents the midpoints between the minima and maxima. Determination of actual averages would require enough full-scale plant evaluations to determine the appropriate distributions of data between the minima and maxima.