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Survey of Coal-Fired Power Plants and Analysis of Selected Fly Ashes

A Task Toward Elucidating Arsenic and Selenium Speciation

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EPRI Project Managers
J. Sanchez
N. Srinivasan

EPRI
3420 Hillview Avenue, Palo Alto, California 94304-1338 ▪ PO Box 10412, Palo Alto, California 94303-0813 ▪ USA
800.313.3774 ▪ 650.855.2121 ▪ askepri@epri.com ▪ www.epri.com

THE ELECTRIC POWER RESEARCH INSTITUTE (EPRI) PREPARED THIS REPORT.

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Principal Investigators
J. Sanchez
N. Srinivasan

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ABSTRACT

It is well established that gas-phase mercury, arsenic, and selenium can be captured in fly ash, a byproduct of coal combustion. But the respective valence states of these trace metals in ash are likely governed by complex interactions among initial feedstock mass concentrations, boiler operating conditions, configurations of downstream environmental control equipment, boiler or fuel additives, and reagents or sorbents used for compliance with mercury and air toxics standards. Furthermore, changes in traditional full-load dispatch for coal-fired units—due to integrating intermittent energy sources and low-cost natural gas—have required operation under flexible load conditions and low- or minimum-load extended periods. Thus, constant and unpredictable variability can impact the quantification of trace metal species present in waste streams at very low levels.

This report describes work that the Electric Power Research Institute has performed as the first task of a larger effort to investigate measurement techniques for arsenic and selenium concentrations in various fly ashes. The report presents a survey of operating U.S. coal-fired electric utility steam generating units that produce fly ash as a combustion byproduct and categorizes units based on coal rank/source, operating conditions, boiler design, and installed environmental controls. Fly ash samples were collected from a group of seven units. The samples underwent traditional characterization analysis and provided a wide array of physical and chemical compositions that will be used by the Georgia Institute of Technology to test various trace metal measurement techniques for arsenic and selenium.

Keywords

Arsenic
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PRIMARY AUDIENCE: Personnel involved in environmental control of trace metals

SECONDARY AUDIENCE: Laboratory personnel

KEY RESEARCH QUESTION

The objective of the research presented in this report is to systematically characterize As and Se speciation within a matrix of representative coal fly ashes using state-of-the-art synchrotron-based spectroscopic and microscopic techniques. As a first step, EPRI conducted a survey of the coal-fired electrical generating units (EGUs) with the goal of identifying a representative subset of units for fly ash sample collection. These samples will then be further characterized, and the resulting information will be used to correlate various fly ash characteristics with As/Se speciation.

RESEARCH OVERVIEW

This report presents the results of a survey of operating coal-fired EGUs that produce fly ash as a combustion byproduct. The survey categorizes units based on coal rank/source, operating conditions, boiler design, and installed environmental controls. Using this knowledge, EPRI collected samples of representative fly ashes for further analysis.

KEY FINDINGS

- A survey of various databases indicated approximately 497 coal-fired EGUs with a gross capacity in megawatts (MWg) of more than 90 MWg that were operating as of 2019. Approximately 48% of these units fired bituminous coals, 37% fired subbituminous coals, 13% fired a mixture of blended coals, and 3% fired lignite.
- Wall-fired and tangential-firing furnace configurations make up more than 90% of the operating fleet. This indicates that most EGUs fired pulverized coal as opposed to crushed coal. Approximately 75% of the EGUs fall in the range of 300–1000 MWg of generating capacity.
- Units were categorized by the type of installed environmental controls for NOx, SOx, and particulate matter. Based on these findings, a group of units was selected to obtain fly ash samples.
- Samples were collected from seven units varying in coal rank, capacity, and type of environmental controls installed. Analysis of major species in the fly ash are presented in the report. Additional characterization will be performed by Georgia Institute of Technology and reported in future publications.

WHY THIS MATTERS

Utilities are addressing compliance with the U.S. Environmental Protection Agency's Coal Combustion Residuals and Effluent Limitation Guidelines regulations. Limits imposed under these regulations set boundaries on the amount of toxic metals (Hg, Se, As, and so on) and other pollutants that EGUs are allowed to discharge to their waste streams. Arsenic and selenium can be captured in the fly ash, but the actual concentrations and their respective valence state could be governed by complex interactions between initial feedstock mass concentrations, furnace operating conditions, configurations of downstream environmental control systems, boiler additives, and reagents and/or sorbent injection.

HOW TO APPLY RESULTS

The results of this study should help interested stakeholders to gain a better understanding of the coal-fired operating fleet and related environmental control configurations. The report presents graphical and tabular summaries of operating units by coal rank, boiler design, and type of environmental control installed as well as combination of integrated controls for NOx, SOx, and particulate matter. The fly ash samples collected and analyzed in this effort represent a subset of those units. Additional trace metal characterization will be conducted and reported by Georgia Institute of Technology, which will aim to investigate novel trace metal measurement techniques that are not widely used by the industry.

LEARNING AND ENGAGEMENT OPPORTUNITIES

- This work was supported by U.S. Department of Energy NETL grant ID DE-FE0031739.

- The study was supported in part by EPRI's work from the Combustion, Emissions, and Carbon Controls for All Fuels Program. Other EPRI programs that relate to this work include Program 238, Water Treatment Technologies, and Program 240, Water Quality and Effluent Guidelines.

EPRI CONTACT: Jose Sanchez, josanche@epri.com, 650.855.2143

PROGRAM: Combustion, Emissions, and Carbon Controls for All Fuels, P210

EPRI
3420 Hillview Avenue, Palo Alto, California 94304-1338 • PO Box 10412, Palo Alto, California 94303-0813 USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com

ACRONYMS, ABBREVIATIONS, AND SYMBOLS

ACFB	atmospheric circulating fluidized bed
Al_2O_3	aluminum oxide
As	arsenic
BH	baghouse
CaO	calcium oxide
CB	blend a low-sulfur coal with a higher-sulfur coal
CC	combustion control
CF	fire a low-sulfur compliance coal
cm^2	square centimeter
cm^3	cubic centimeter
eGRID	Emissions & Generation Resource Integrated Database (EPA)
EGU	electric utility steam generating unit
EPA	U.S. Environmental Protection Agency
ESP	electrostatic precipitator
ESPc	cold-side electrostatic precipitator
ESPh	hot-side electrostatic precipitator
FeO	iron oxide
FF	fabric filter
Hg	mercury
ILB	Illinois Basin
K_2O	potassium oxide
lig	lignite
mg/cc	milligrams per cubic centimeter
MgO	magnesium oxide
MnO	manganese (II) oxide

MSW	municipal solid waste
µm	micron(s)
MWg	gross capacity in megawatts
Na_2O	sodium oxide
NAAP	Northern Appalachian Basin
NOx	nitrogen oxide
O_3	ozone
P_2O_5	phosphorus pentoxide
%wt	weight percent
PM	particulate matter
PRB	Powder River Basin
SCR	selective catalytic reduction
SCRUB	scrubber
sdFGD	semi-dry flue gas desulfurization
Se	selenium
SiO_2	silicon dioxide
SNCR	selective noncatalytic reduction
SOx	sulfur oxides
TiO_2	titanium dioxide
wFGD	wet flue gas desulfurization
XRF	X-ray fluorescence

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1 INTRODUCTION

Many U.S. electric utilities are addressing compliance strategies for upcoming regulations, such as the U.S. Environmental Protection Agency's (EPA's) revised Coal Combustion Residuals and Effluent Limitation Guideline. These regulations place limits on the concentrations of trace metals—mercury (Hg), selenium (Se), arsenic (As), and so on—and other pollutants discharged by coal-fired electric utility steam generating units (EGUs) in their waste streams.

It is well established that gas-phase mercury, arsenic, and selenium can be captured in fly ash, a byproduct of coal combustion. But the respective valence states of these trace metals in ash are likely governed by complex interactions among initial feedstock mass concentrations, boiler operating conditions, configurations of downstream environmental control equipment, boiler or fuel additives, and reagents or sorbents used for mercury and air toxics standards compliance. Furthermore, changes in traditional full-load dispatch for coal-fired units—due to integrating intermittent energy sources and low-cost natural gas—have required operation under flexible load conditions and low- or minimum-load extended periods. Thus, constant and unpredictable variability can impact the quantification of trace metal species present in waste streams at very low levels.

Objective

The objective of this research is to systematically characterize As and Se speciation within a matrix of representative coal fly ashes using state-of-the-art synchrotron-based spectroscopic and microscopic techniques. The resulting information will be used to develop a comprehensive correlation database that is searchable for coal rank/source, operating condition, As/Se speciation, and As/Se mobility in the environment.

This report describes work that the Electric Power Research Institute (EPRI) has performed as the first task of the project to further the research objective. It presents the results of a survey of operating U.S. coal-fired EGUs that produce fly ash as a combustion byproduct. The survey categorizes units based on coal rank/source, operating conditions, boiler design, and installed environmental controls. Using this knowledge, EPRI has collected a sample of representative fly ashes for further analysis by the Georgia Institute of Technology.

2
SURVEY OF CURRENT U.S. COAL-FIRED EGUs PRODUCING FLY ASH

Approach

EPRI's first task was to conduct a survey to determine the current state of U.S. coal-fired EGUs producing fly ash as a combustion byproduct. For this effort, several public and internal databases were searched, including EPA's Emissions & Generation Resource Integrated Database (eGRID) [1], a "comprehensive source of data from EPA on the environmental characteristics of almost all electric power generated in the United States." Other databases, such as the S&P Global Power Plant Book and Screener Tool 2020 [2], were also cross-referenced with EPRI's own internal collections of databases on plant systems [3].

The criteria used to search the databases included generating nameplate capacity (gross capacity in megawatts [MWg]), boiler firing configurations, coal ranks, and installed emission controls for nitrogen oxides (NOx), sulfur oxides (SOx), particulate matter (PM), and Hg. The databases were actualized up to December 2019. Units with a capacity of less than 90 MWg were excluded.

Results

Units Categorized by Generating Capacity

Figure 2-1 summarizes the compiled coal-fired unit dataset, including 497 units categorized by gross generating capacity. The bar plots indicate that most of the operating units fall in the range of 100–800 MWg. The horizontal bar plot on the left of Figure 2-1 shows the actual number of units in a given MWg range, and the vertical bar plot on the right shows the percent of total generating capacity occupied by each range.

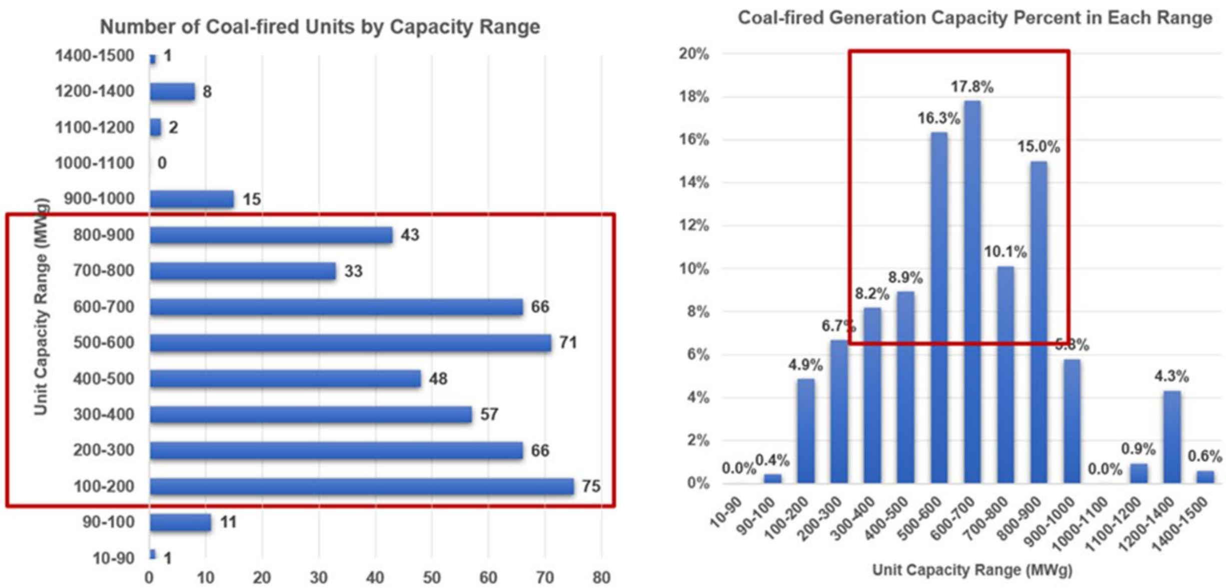

Figure 2-1
Summary of operating coal-fired units categorized by gross generating capacity

Units Categorized by Rank

The dataset units were also categorized according to major coal rank classification as firing bituminous, subbituminous, lignite, or blended coals. Figure 2-2 is a pie chart showing a distribution of the units according to coal rank. Most of the units fired bituminous coals (47.7%), followed by subbituminous (36.9%) and blended coals (12.3%). Blended coals were mostly bituminous/subbituminous blends, whereas only a few units blended lignite with subbituminous coal. Only a small fraction of the units fired lignite (3.1%).

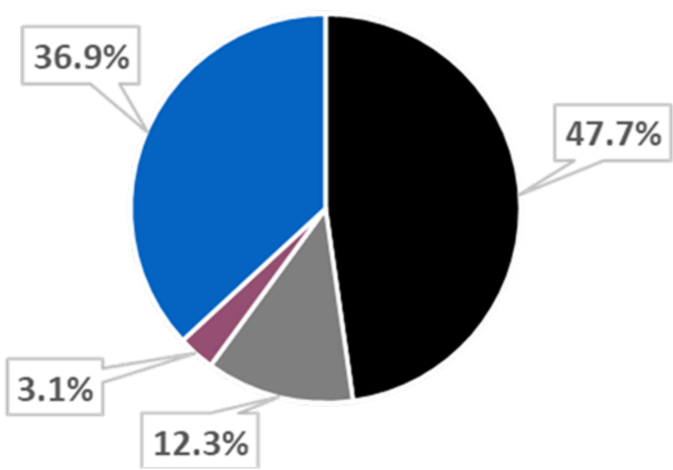

Figure 2-2
Distribution of operating units by coal rank

Units Categorized by Boiler Design

The analysis also categorized the dataset units by combustion boiler design—including front-wall, opposed-wall, tangential, cyclone, opposed turbo-fired, and turbo-fired atmospheric circulating fluidized bed (ACFB) designs. This categorization is useful because the quantity and quality of fly ash depend on boiler design. For instance, most tangential and circular burner wall-fired units (both front and opposed wall-fired) typically generate a ratio of fly ash to bottom ash in the range of 60–90% fly ash to 40–10% bottom ash. *Bottom ash* is defined as the mineral matter deposits that do not exit the boiler with the flue gases but instead flow through the bottom of the boiler hopper as molten slag. Cyclone-type boilers generate a large fraction of bottom ash, generally in the 60–80% range.

As shown in Figure 2-3, most of the dataset units are tangential (41%) or opposed wall-fired (33%) designs. A few front wall-fired units remain in operation (13%); these units have lower generating capacity (less than 250 MWg) than opposed-fired designs.

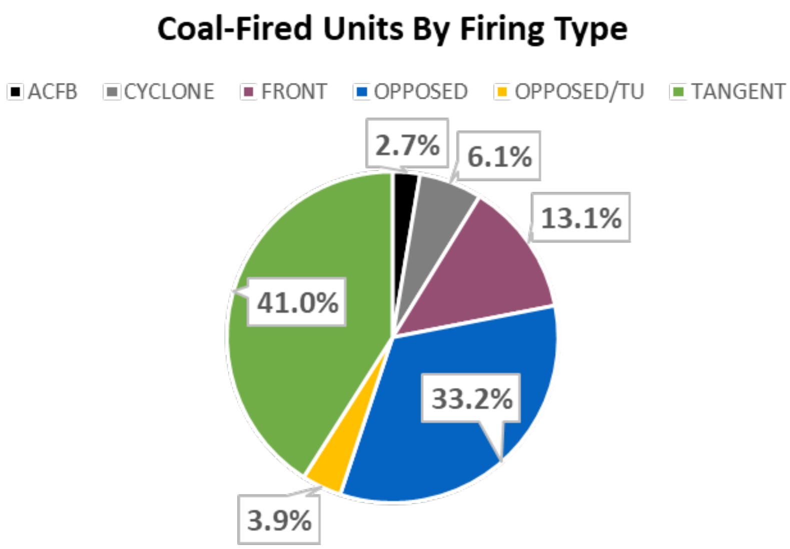

Figure 2-3
Distribution of operating units by boiler design

The distribution of coals fired in each boiler design is shown in Figure 2-4. Tangential boiler units fire 44% bituminous and 42% subbituminous coals. Both front and opposed wall-fired units burn more than 52% bituminous coals, whereas cyclone units are dominated by subbituminous coals. The smaller numbers of turbo-fired ACFB units also fire mostly bituminous coals.

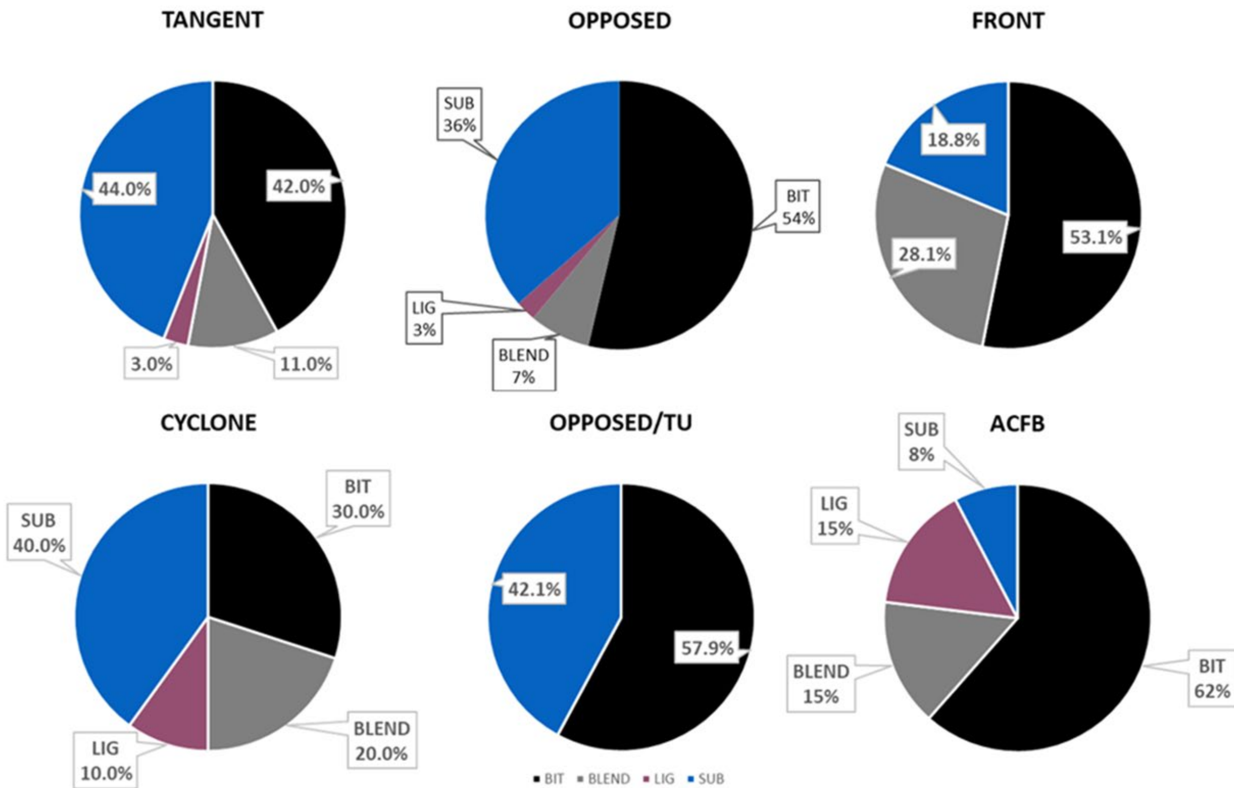

Figure 2-4
Distribution of coals fired by boiler design

Units Categorized by Type of Environmental Controls

The dataset was also categorized according to existing environmental controls for NOx, particulate matter, and SOx. Results for these categories are described in the following.

NOx Controls

All coal-fired units must comply with EPA regulations concerning NOx emissions as a precursor for ground-level ozone (O_3), regional haze, and acid rain. Figure 2-5 depicts the distribution of NOx control technologies for the dataset.[1] Although most units use a selective catalytic reduction (SCR) reactor or selective noncatalytic reduction (SNCR) reactor, 26% of the units use combustion controls (CC) or other boiler control options, such as separated overfire air, low-NOx burners, combustion optimizers, and so forth.

[1] In the figures and tables in this section, *na* means that the database did not specify the exact type of pre-combustion NOx control technology for the labeled units, and the current survey could confirm only that the units did not employ post-combustion NOx controls.

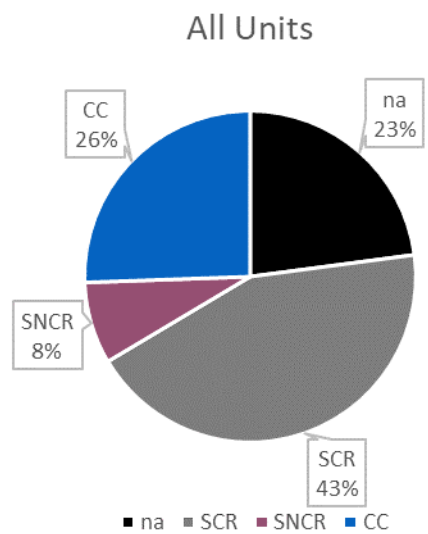

Figure 2-5
Distribution of NOx controls for all operating units

Figure 2-6 shows the distribution by coal rank for these NOx control technologies. Most of the units equipped with SCR fire bituminous coals, followed by subbituminous and blended coals. Most of the units equipped with SNCR also fire bituminous coals or a blend of two coal ranks. Units employing combustion control methods for NOx reduction fire various fuels.

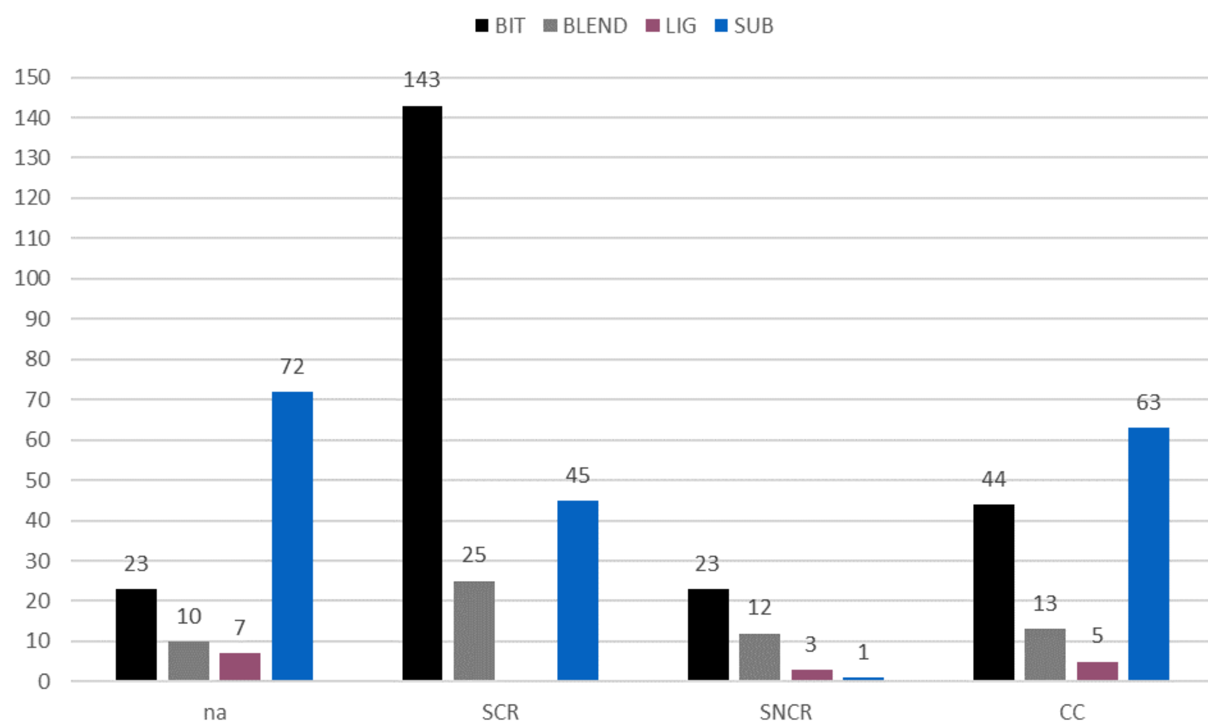

Figure 2-6
Distribution of units by primary NOx control type and respective coal ranks

PM Controls

Figure 2-7 shows the distribution of units equipped with electrostatic precipitators (ESPs) or baghouses (BHs)—the two most common PM control technologies used in the United States. Most ESPs in the United States are dry, cold-side installations (ESPc) where the ESP inlet temperature is a function of the air heater outlet temperature. These ESPs typically operate between 250°F and 350°F (121–177°C). In contrast, approximately 45 (10%) of U.S. operating units are hot-side ESPs (ESPh) installed upstream of the air preheater, where temperatures can range from 650°F to 750°F (343–399°C). These hot-side ESPs are installed on units where fly ash resistivity—a key variable in ESP performance—is lower at hot-side temperatures than at cold-side temperatures. Existing ESPs can collect up to 99.9% of inlet fly ash depending on ESP design, mechanical condition, fuel quality, and plant operating conditions.

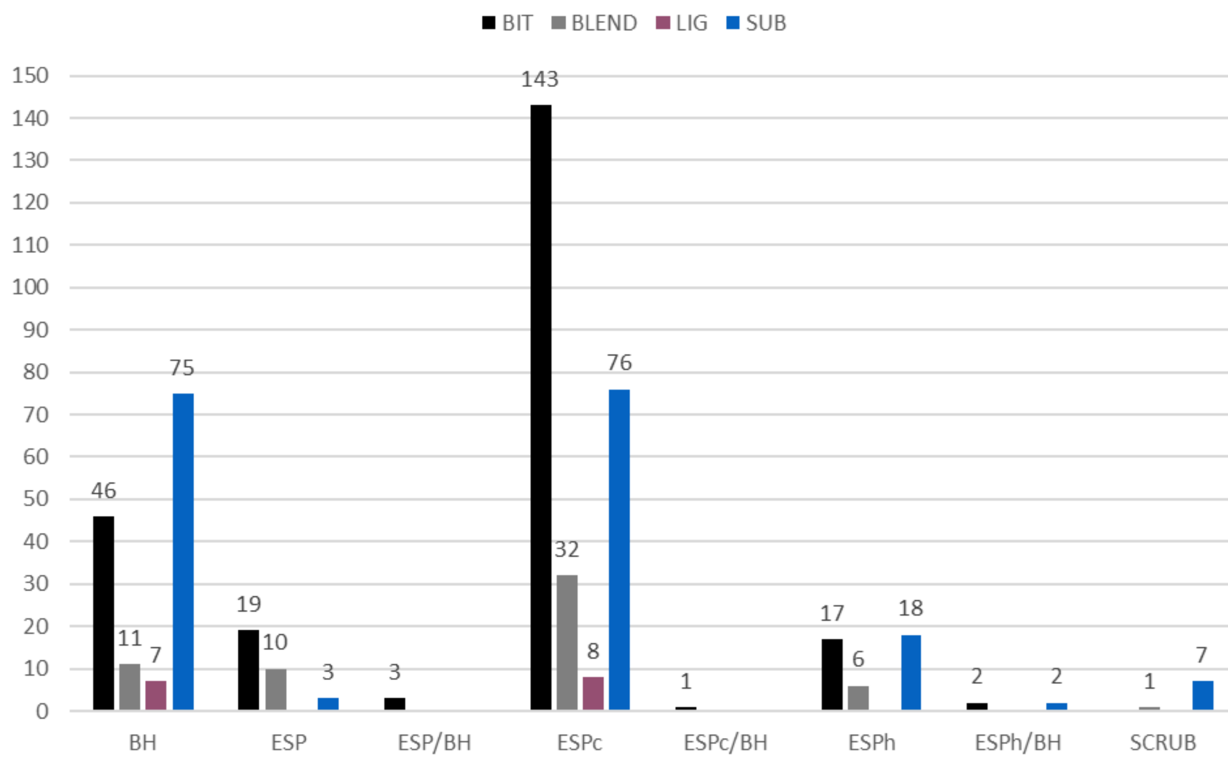

Figure 2-7
Distribution of units by primary PM control type and respective coal ranks

BHs or fabric filters (FFs) also capture fly ash with high efficiency in the range of 99.9%. BHs are installed on 147 units (approximately 31% of operating units), with 77 units firing subbituminous coals, 46 units firing bituminous coals, 7 units firing lignite, and the balance firing coal blends. Fewer than eight units operate without an ESP or BH; instead, they capture particulate in the specific design of wet flue gas desulfurization systems.

ESPs and BHs remove fly ash particulate from the hot flue gas either by collection on plates forming a dust cake or by filtration through FF bags forming a dust cake. The dust cake is mechanically removed and falls into collection hoppers at the bottom of the system. The collection hoppers are ideal locations for fly ash sampling.

For ESPs, the collected ash differs in quantity and quality at locations along the flue gas path from inlet to outlet fields. For instance, the inlet fields tend to collect 70–85% of total incoming dust and capture the larger ash size fractions. The downstream fields capture the remaining dust containing smaller ash-size fractions. The ESP outlet field will likely collect less than 5% of the particulate entering the ESP.

A few units were classified as having no ESP or FF. Instead, these units integrated PM control with the desulfurization system. Only a few of these units remain in operation, as indicated by the SCRUB designation in Figure 2-7.

SOx Controls

Several technological approaches can be used to remove sulfur dioxide from flue gas. The most prevalent technology applied across the U.S. coal-fired fleet is wet flue gas desulfurization (wFGD) using limestone as the reagent medium. Approximately 57% of units are equipped with one of several different types of wFGD; for the purpose of this survey, all the different types are reported as wFGDs. Most of these wFGD systems are designed for units firing bituminous coals that generally have higher sulfur content (greater than 2% by weight).

The second most widely used desulfurization technology—firing low-sulfur coal—is employed at 26% of the units in operation. These units either fire a low-sulfur compliance coal (CF) or strategically blend a low-sulfur coal with a higher-sulfur coal (CB) to achieve the desired outlet SO_2 levels. They are typically less than 350 MWg in gross capacity.

Semi-dry systems, including spray dry absorbers and circulating dry fluidized scrubbers, are installed across 10% of units in service. Finally, a smaller fraction of units employs dry FGD technology that injects sorbents directly into the flue gas as a primary method of SO_2 control. Figure 2-8 shows the distribution by coal rank for these SOx control technologies.

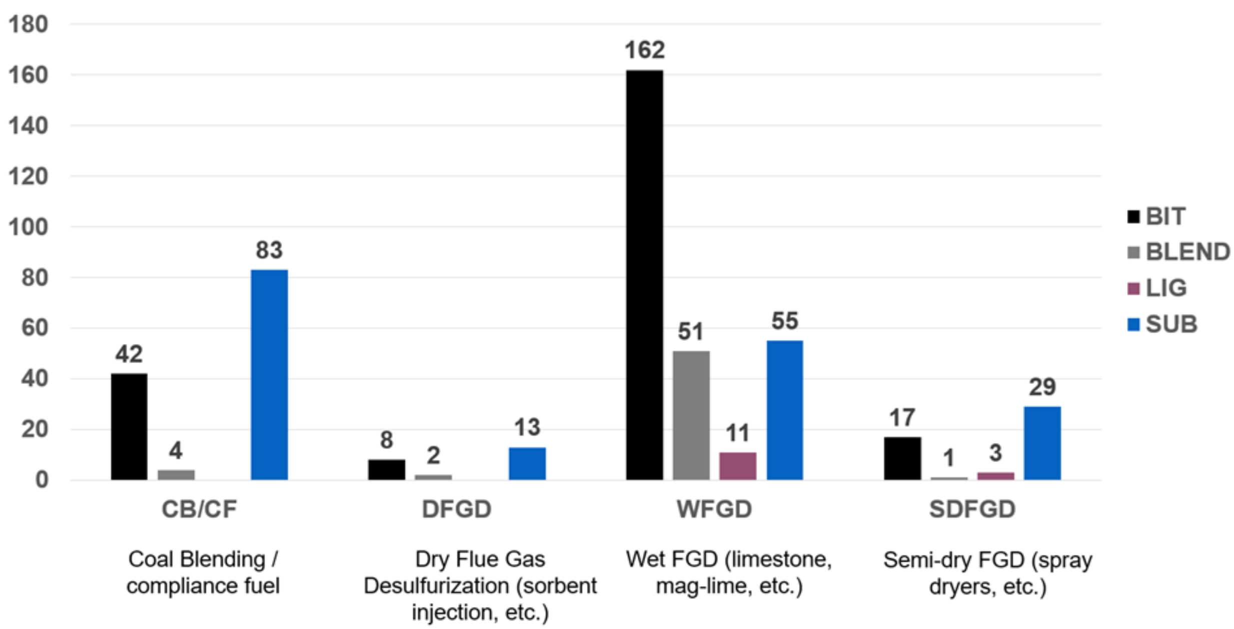

Figure 2-8
Distribution of units by primary SOx control type and respective coal ranks

Environmental Control Combinations

NOx Capture Plus Downstream PM and SOx Controls

The unit dataset was also compiled to illustrate the different combinations of environmental controls used across the industry, based on coal rank. Figure 2-9 presents the distribution by coal rank for units that are equipped with CC or other undisclosed technologies for NOx capture plus other environmental control systems. Figure 2-9 shows that a large fraction of units firing subbituminous coals and relying on fuel blending for SO_2 removal falls under this category. Most units that use this type of NOx control technology also use cold-side ESPs. Although other configurations fall under this category, they constitute only a small percentage of the total units.

Figure 2-10 shows the distribution of units that use SNCR as the primary NOx control technology and account for approximately 8% of the total operating units. Most of these units fire bituminous or bituminous blends and are equipped with either hot- or cold-side ESPs for PM control. Of these units, about one-third are equipped with wFGD systems for SO_2 control. Finally, units with baghouses for PM removal under this NOx control category have either semi-dry or wet flue gas desulfurization systems. Based on survey findings, units burning subbituminous coal are not operational under this category.

The final NOx control technology covered in this survey describes units equipped with SCR—the technology for NOx control most widely used in the United States. The distribution of downstream PM and SO_2 control options for these units is illustrated in the bar graphs of Figure 2-11. Approximately 31% of the units that use SCR fire bituminous coal, and most are equipped with a cold-side ESP. The remaining SCR units using baghouses for particulate control deploy different SO_2 control technologies, depending on the type of coal fired.

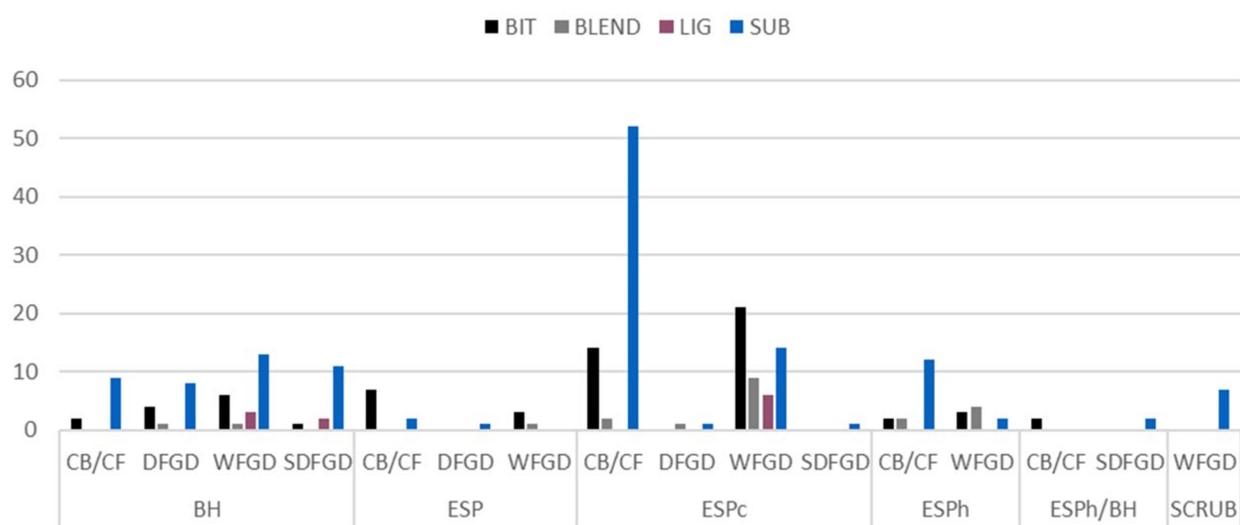

Figure 2-9
Distribution by coal rank of units with combustion or undisclosed NOx controls plus downstream particulate matter and SOx controls

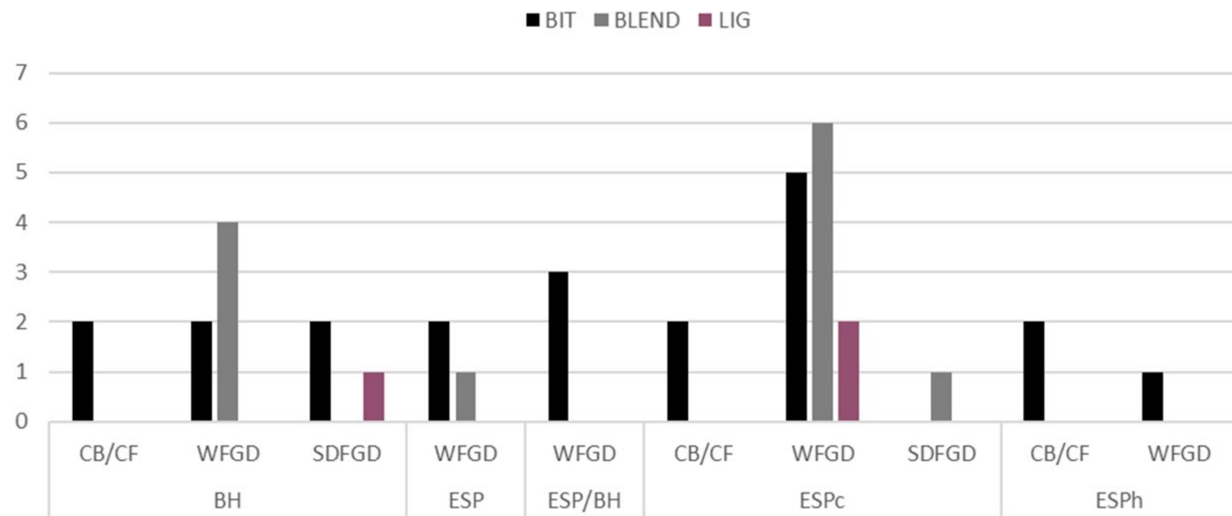

Figure 2-10
Distribution by coal rank of units with SNCR plus downstream particulate matter and SOx controls

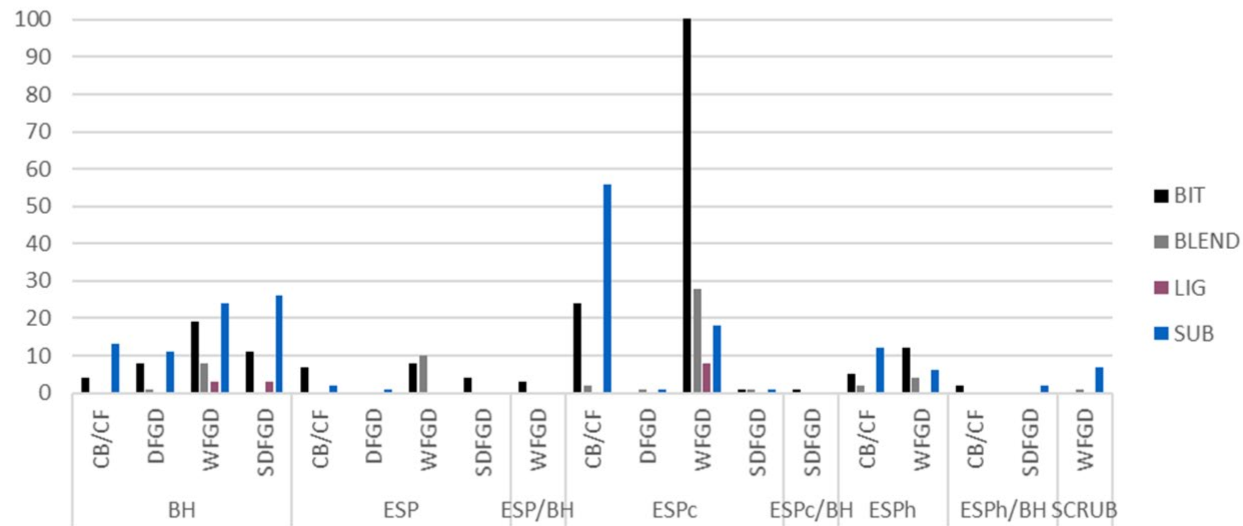

Figure 2-11
Distribution by coal rank of units with SCR plus downstream particulate matter and SOx controls

Distribution by Coal Rank of Units with Combined NOx, Particulate Matter, and SOx Controls

Based on the preceding survey results, the distribution by coal rank of units with combined Nox, particulate matter, and SOx controls can be summarized as follows:

- *For units firing bituminous coals*, the combination of SCR, ESP (either cold-side or hot-side), and wFGD systems makes up the largest fraction of the dataset, as illustrated in Figure 2-12. Units lacking post-combustion NOx controls (that is, without SCR or SNCR) but equipped with some form of post-combustion SO_2 control accounted for the second-largest fraction.
- *For units firing subbituminous coals*, as shown in Figure 2-13, fewer units were equipped with SCR or SNCR. Most units relied on CC or CB for NOx compliance. The larger fraction of units equipped with post-combustion SO_2 control depends on semi-dry systems followed by wFGD systems. ESPs remain the largest segment of PM control, although more subbituminous than bituminous units are equipped with baghouses as the primary PM control.
- *For units firing a combination of coals or blended coals,* the combination of post-combustion NOx controls, electrostatic precipitators, and wFGD systems is most common, as illustrated in Figure 2-14.

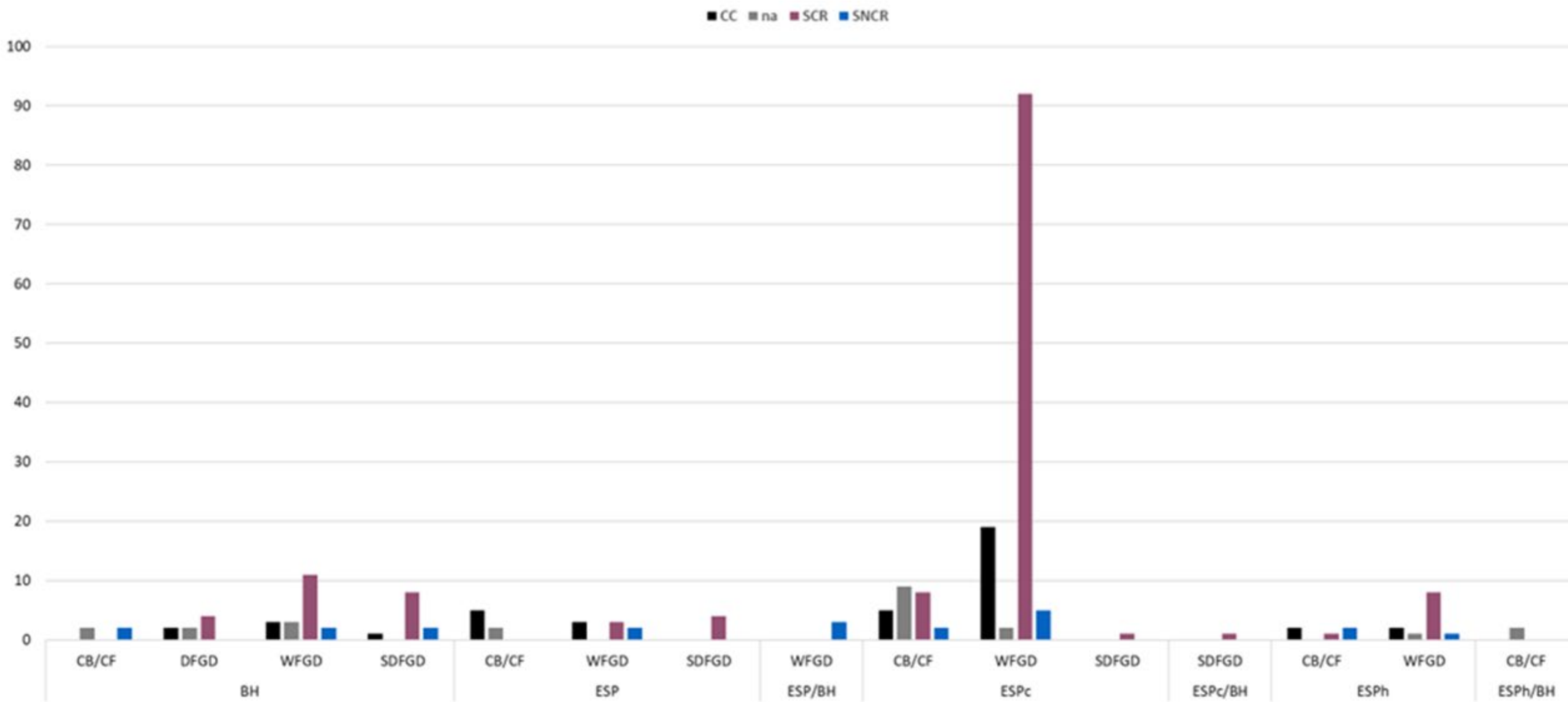

Figure 2-12
Distribution of coal-fired units by NOx, particulate matter, and SOx controls

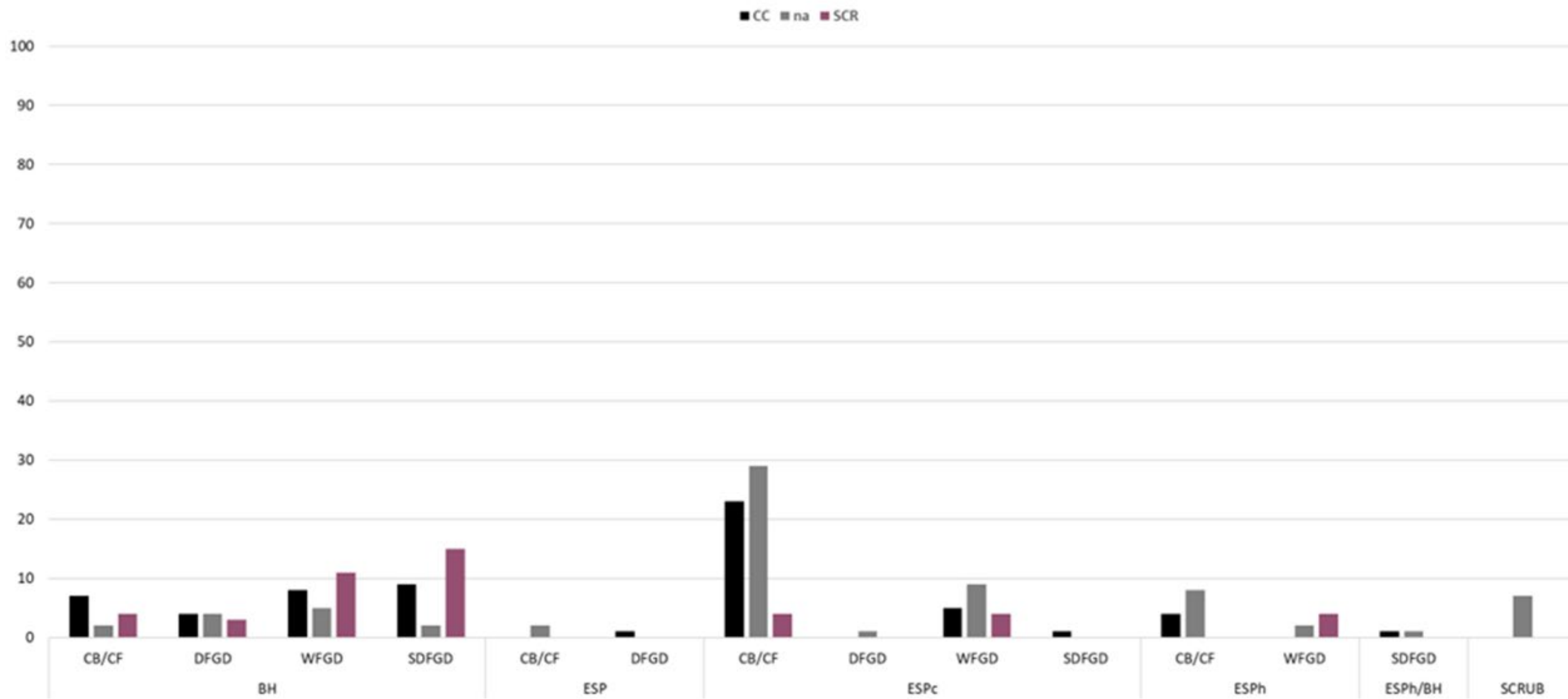

Figure 2-13
Distribution of subbituminous coal-fired units by NOx, particulate matter, and SOx controls

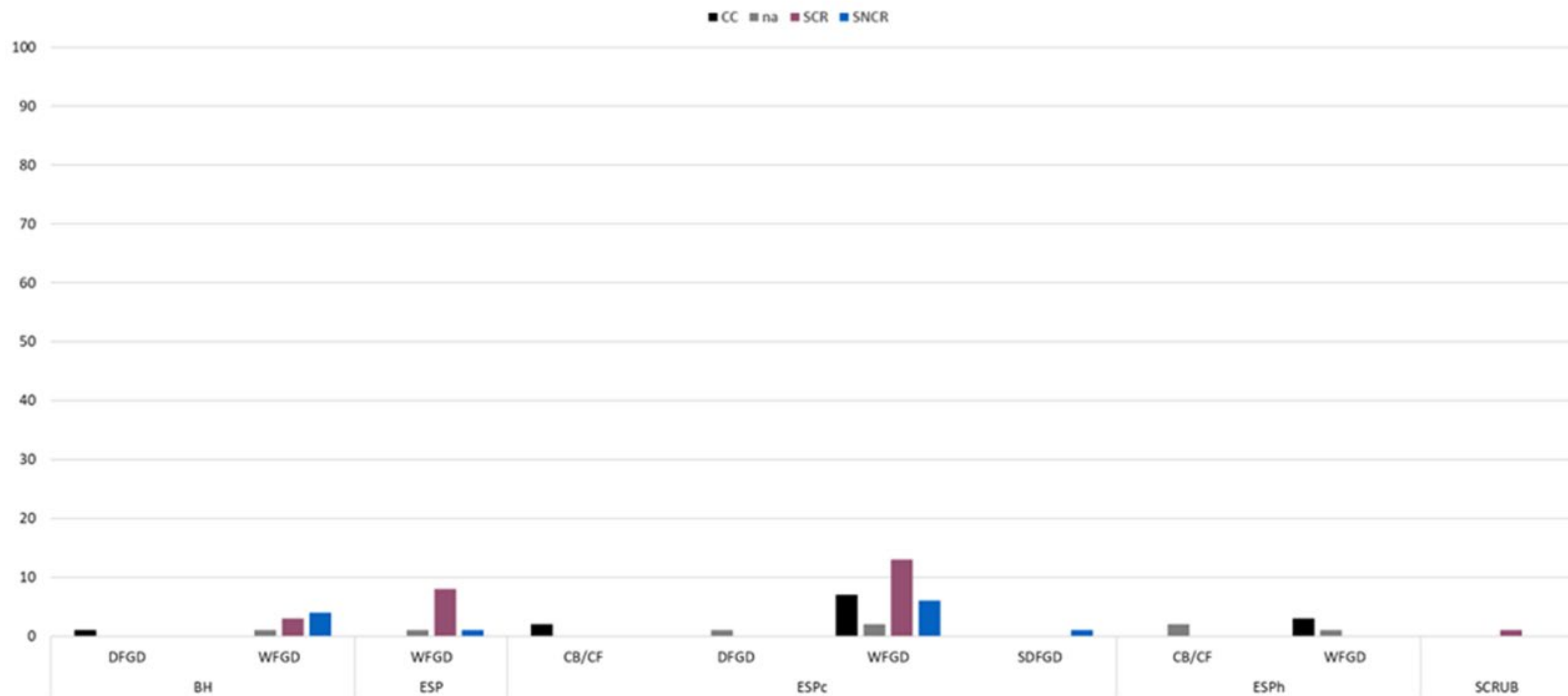

Figure 2-14
Distribution of blended coal-fired units by NOx, particulate matter, and SOx

Pre-Combustion NOx Controls

This section summarizes the findings for units with pre-combustion NOx controls plus particulate matter and SO_2 controls—further categorized by boiler design. Units in this pre-combustion NOx group apply one or more technologies, such as low-NOx burners, overfire air, or combustion optimization controls. Boiler designs include tangential, wall-fired, and cyclone, which are the most common designs in operation. The wall-fired design includes both the front-wall and opposed-wall firing options.

Categorization by boiler design is important because the combustion process, level of emissions, and fly ash quality frequently differ among these designs. This categorization is shown in bar plots in Figures 2-15 through 2-17, where different colors represent different types of coal. Due to the large number of categories and subcategories within individual environmental control types, the bar plots are separated into pre-combustion (CC or na) and post-combustion (SNCR or SCR) NOx control technologies. Figures 2-15 through 2-17 focus on units with pre-combustion NOx control options, whereas Figures 2-18 through 2-20 categorize units with post-combustion NOx control options.

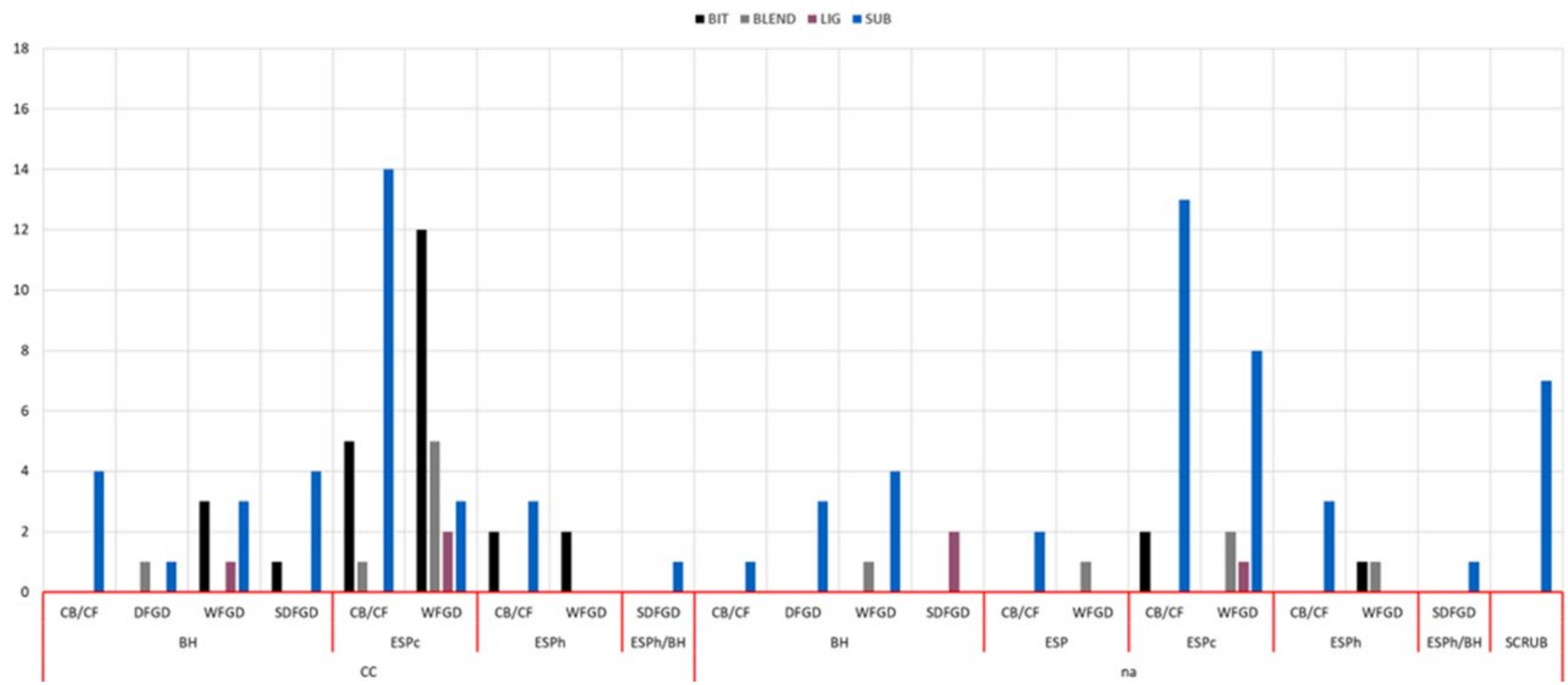

Figure 2-15
Distribution by coal rank of tangential-fired units with pre-combustion NOx controls plus particulate matter and SOx controls

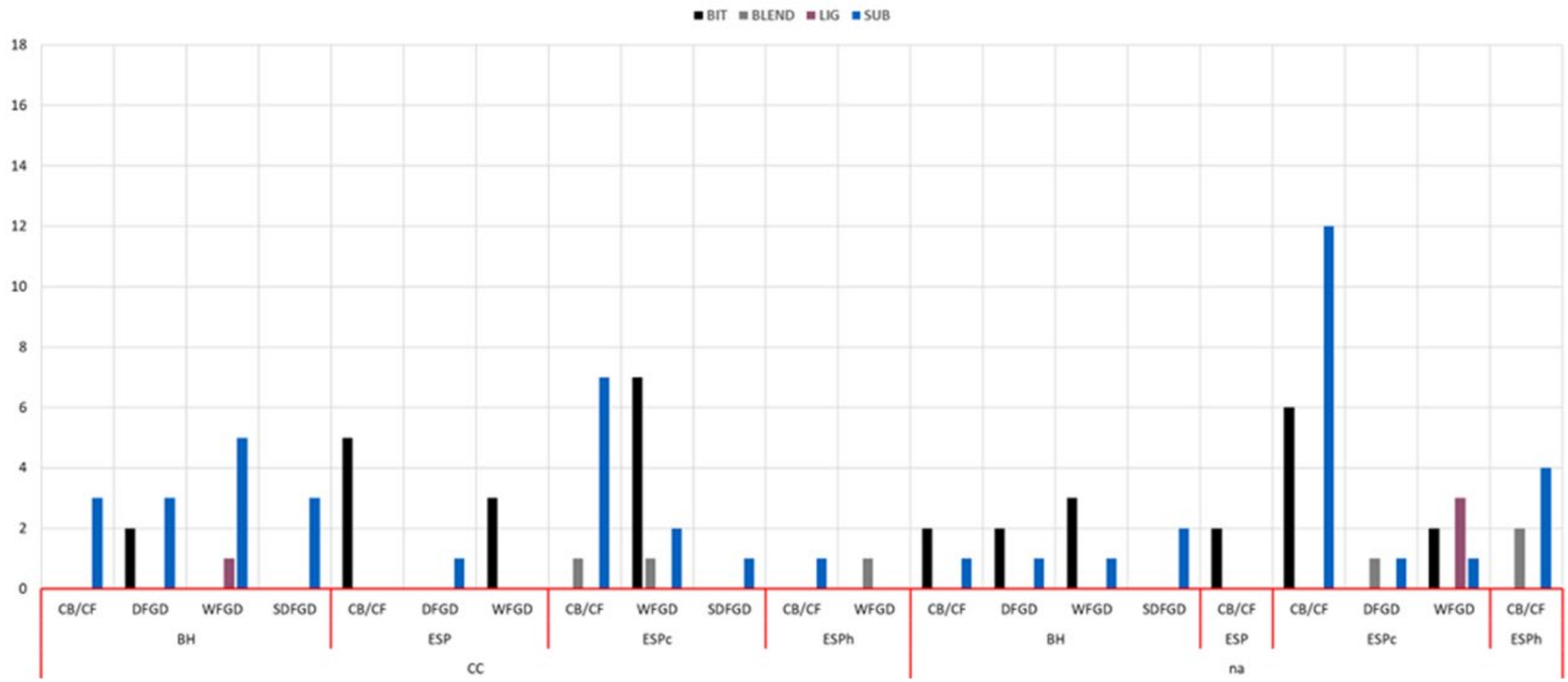

Figure 2-16
Distribution by coal rank of wall-fired (front and opposed) units with pre-combustion NOx controls plus particulate matter and SOx controls

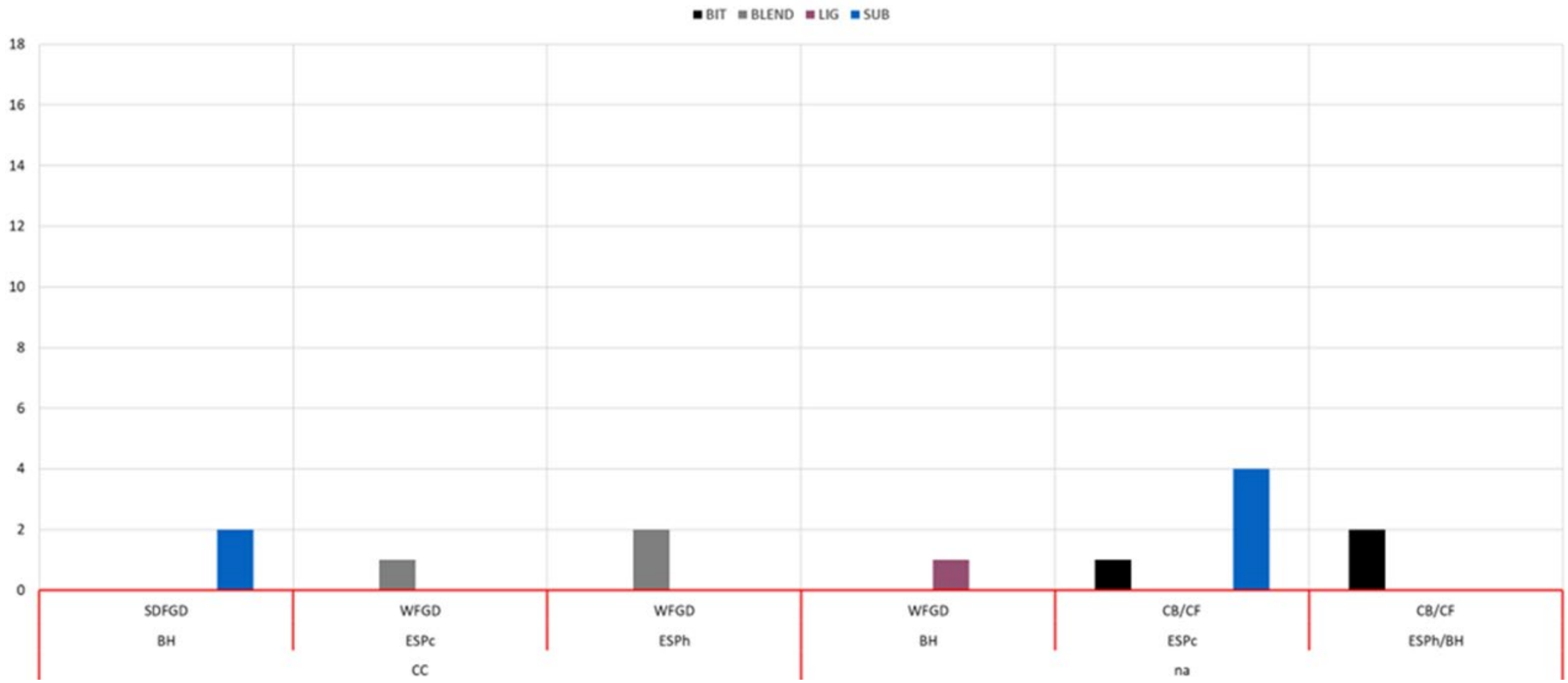

Figure 2-17
Distribution by coal rank of cyclone-fired units with pre-combustion NOx controls plus particulate matter and SOx controls

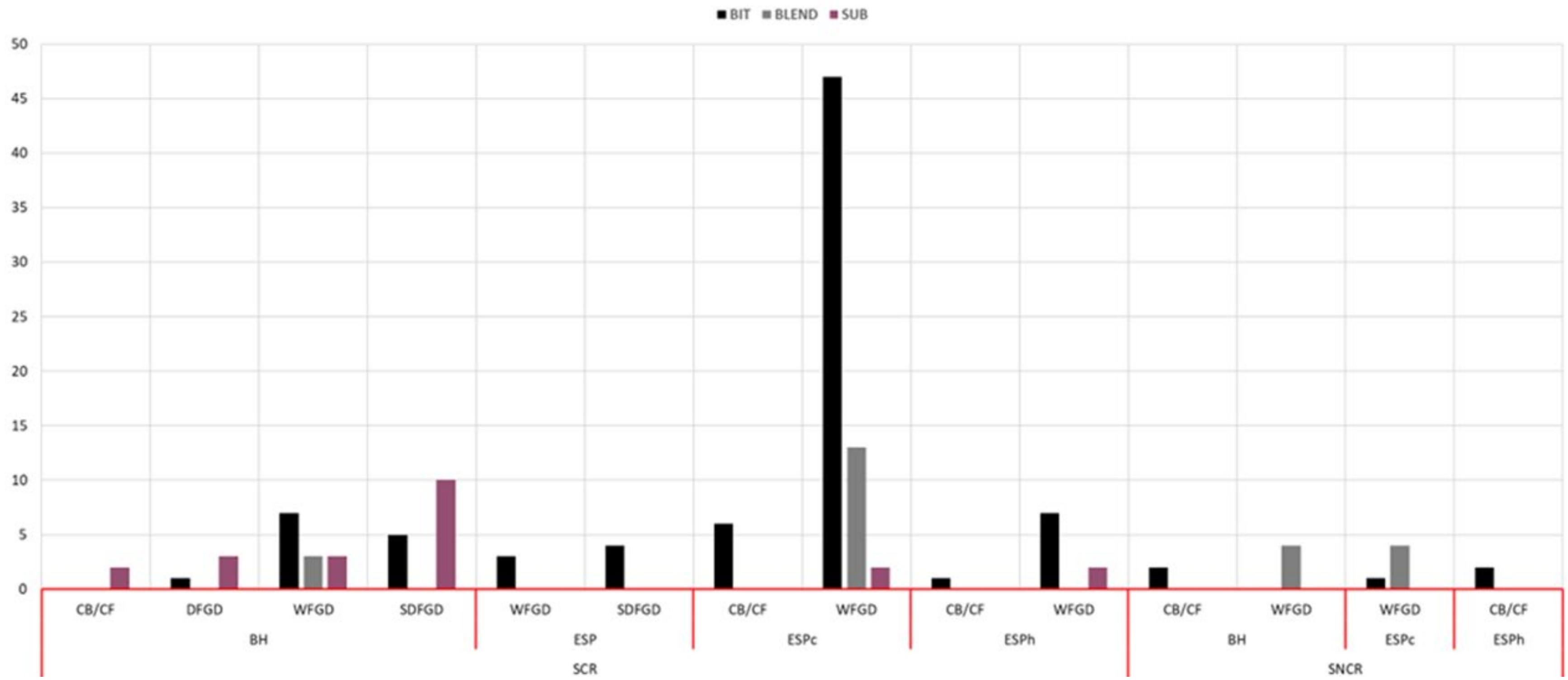

Figure 2-18
Distribution by coal rank of wall-fired (front and opposed) units with post-combustion NOx controls plus particulate matter and SOx controls

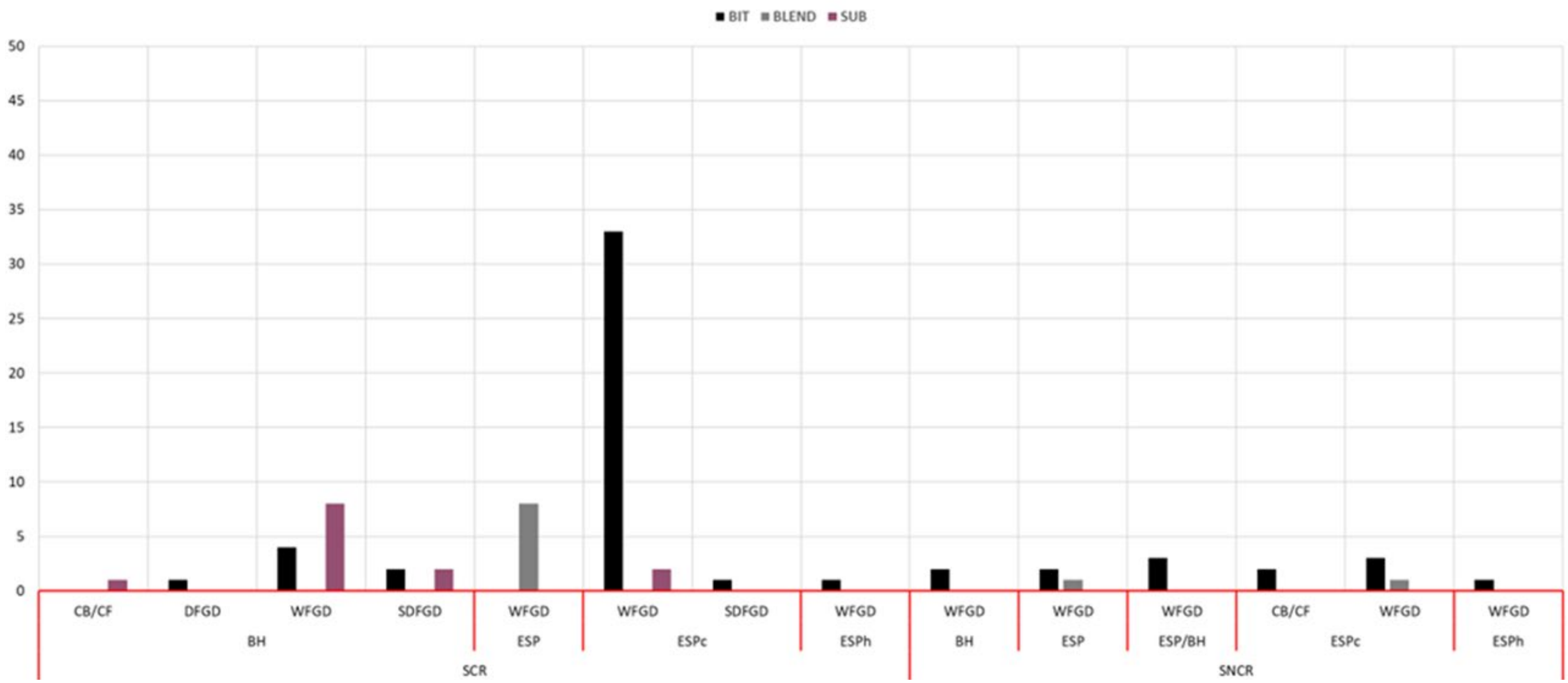

Figure 2-19
Distribution by coal rank of tangential-fired units with post-combustion NOx controls plus particulate matter and SOx controls

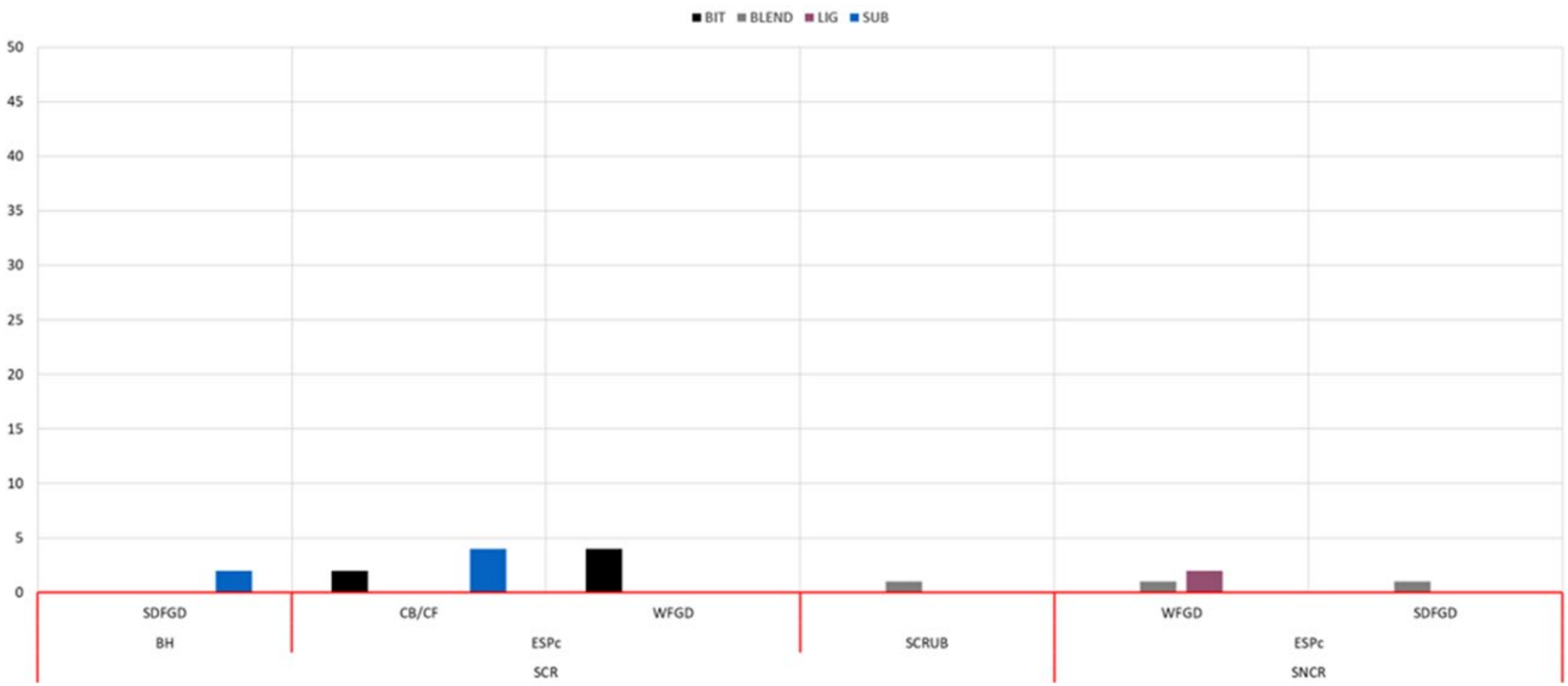

Figure 2-20
Distribution by coal rank of cyclone-fired units with post-combustion NOx controls plus particulate matter and SOx controls

Figure 2-15 shows that most of the tangential-fired boilers, regardless of coal rank, had some form of pre-combustion NOx control technology. Most of these units were equipped with cold-side ESPs for PM removal. The bituminous units typically relied on wet FGDs, whereas the subbituminous units depended on blending (CB) or firing compliance low-sulfur fuels (CF) for SO_2 control.

Figure 2-16 shows that wall-fired units followed a similar pattern, although the number of wall-fired units was smaller than the number of tangential units (93 versus 121). Most of the limited number of cyclone units (13) shown in Figure 2-17 fired subbituminous coals and did not have a wFGD system for SO_2 capture.

Post-Combustion NOx Controls

Most units equipped with post-combustion NOx controls (that is, SCR or SNCR) had wall-fired boilers, including either front- or opposed-wall designs. The SCR-equipped units fired mostly bituminous coals or coal blends and had cold-side ESPs and wet flue gas desulfurization systems, as shown in Figure 2-18. SNCR-equipped units fired bituminous coals or coal blends and represent a smaller fraction of this group.

Figure 2-19 shows the environmental control type distribution for tangential-fired units, where most of the units fired bituminous coals or coal blends and had cold-side ESPs and wFGD systems. Tangential-fired units equipped with SNCR were in the minority.

Figure 2-20 displays the control type distribution for cyclone-fired units. Twelve of these units were equipped with SCR and some form of SO_2 control, as noted on the bar plots. There were four more cyclone units with post-combustion NOx controls than with pre-combustion NOx controls (17 versus 13).

3
FLY ASH SAMPLE COLLECTION

Approach

Based on the previously described survey findings, the research team identified a representative subset of candidate units from which to collect fly ash samples. The targeted sample collection points were existing particulate control devices, such as ESPs and FFs. To select candidate units, the team created a matrix of coal feedstock sources/types, boiler designs, and upstream environmental control systems/operating modes. During sample collection, they documented key information, including fly ash sample history, sample representativeness, and plant operating conditions (for example, load demand, combustion staging, and use of additives).

Results

Summary of Categorized Units

Table 3-1 shows the distribution of surveyed units categorized by coal rank, boiler design, NOx control, particulate matter control, and SOx control. Table 3-1 indicates that most bituminous-fired units had opposed wall-fired or tangential boiler designs—both equipped with SCR, cold-side ESPs, and wet flue gas desulfurization systems. Most units firing coal blends also fell into this category. Subbituminous-fired units had mostly tangential, followed by opposed-wall, boiler designs—and were also equipped with cold-side ESPs. For SOx control, only 14 of the subbituminous-fired units were equipped with wFGD. Based on these results, seven units were selected from among those in operation at the start of this project. The specific configuration of these units is summarized in Table 3-2. Fly ash samples from these units were collected at the ESP or FF hoppers.

Table 3-1
Distribution of units categorized by coal rank, boiler design, and emission control configuration

Coal	Boiler Design	NOx	PM	SOx	Unit Count
Bit	Front	CC	ESPc	CB/CF	5
		SCR	ESPc	wFGD	5
	Opposed	SCR	ESPc	wFGD	47
	Opposed turbo	SCR	ESPc	CB/CF	8
	Tangential	CC	ESPc	wFGD	12
		SCR	ESPc		33

Table 3-1 (continued)
Distribution of units categorized by coal rank, boiler design, and emission control configuration

Coal	Boiler Design	NOx	PM	SOx	Unit Count
Blend	Front	SCR	ESPc	wFGD	11
	Opposed	SNCR	ESPc	CB/CF	8
	Tangential	SCR	ESPc	wFGD	8
Sub	Front	na	ESPc	CB/CF	5
	Opposed	CC	ESPc	CB/CF	5
		SCR	BH	sdFGD	9
	Opposed turbo	CC/SCR	ESPh	CB/CF	8
	Tangential	CC	ESPc	wFGD	14
		na	ESPc	CB/CF	13
		SCR	BH	wFGD	8

Table 3-2
Summary of units from which fly ash samples were collected

Unit ID	Fuel Fired	Operating Capacity (MWg)	Boiler Design + Emission Control Configuration
A	Bit–ILB	950	Tangential + SCR + ESPc or BH + wFGD
B	Sub–PRB	890	Tangential + SCR + BH + wFGD
C & D	Sub–PRB	680	Opposed + ESPc
E	Sub–PRB 85% + Bit–MSW 15%	540	Tangential + ESPc
F	Bit–ILB	570	Tangential + ESPc + BH + wFGD
G	Bit–ILB	840	Opposed + ESPc + BH + wFGD
H	Bit–NAPP + Ref	684	Opposed + SCR + ESPc

Characterization of Fly Ash Samples

The collected fly ash samples were sent to the Georgia Institute of Technology for further analyses, which included particle properties and composition analysis. EPRI sent samples to SGS Mineral Services for particle size distribution analysis by laser scattering and bulk density analysis using the ASTM C188-17 Standard Test Method for Density. Georgia Technology Laboratory sent samples for analysis of fly ash composition using X-ray fluorescence and trace element species. Table 3-3 summarizes mean diameter, surface area, and bulk density for the collected fly ash samples, and Table 3-4 summarizes the major species composition for each respective sample. The results of analysis of arsenic and selenium on these fly ash samples, using more advanced techniques, will be presented by the Georgia Institute of Technology in a separate report.

Table 3-3
Summary of particle size distribution parameters for collected fly ash samples

Unit ID	Dmean (μm)	Surface Area (cm^2/cm^3)	Bulk Density (mg/cc)
A	30.2	4,996	2.37
B	23.9	7,017	2.69
C	13.2	9,725	2.58
D	13.1	9,873	2.57
E	21.2	9,233	2.56
F	8.2 / 108	16,478 / 892	2.53
G	17.4	7,314	2.48
H	41.8	3,569	2.63

Table 3-4
Normalized composition of fly ash samples—major elements by X-ray fluorescence analysis (as oxides, excluding undetermined species, %wt)

Plant ID	A	B	C	D	E	F	G	H
SiO_2	51.05	37.79	41.64	41.07	44.47	42.14	46.39	41.93
TiO_2	1.10	1.22	1.19	1.34	1.36	0.81	1.07	0.98
Al_2O_3	22.57	17.14	19.59	20.98	21.85	17.43	19.16	22.19
FeO	15.65	5.57	5.01	5.08	8.81	27.10	14.22	23.50
MnO	0.03	0.04	0.05	0.04	0.03	0.03	0.06	0.04
MgO	1.26	6.57	4.73	4.42	3.51	1.64	2.63	1.27
CaO	4.94	28.70	18.60	17.61	17.07	8.50	13.31	7.48
Na_2O	0.84	1.92	7.75	8.00	1.23	0.51	0.99	0.71
K_2O	2.34	0.35	1.04	0.85	0.93	1.78	2.03	1.65
P_2O_5	0.25	0.74	0.47	0.64	0.78	0.10	0.19	0.29
Total	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00

4 CONCLUSIONS

A survey of EGUs currently operating in the U.S. coal-fired generating fleet was completed by EPRI. The results of the survey, which categorized each unit according to installed pollution control technologies for NOx, SOx, and particulate matter, were used to select a sample subset of EGUs. The selected subset of EGUs provided a wide array of representative operating units that fire various coal ranks and have different pollution control configurations. Fly ash samples were collected from seven EGUs in this group. The samples underwent typical characterization analysis, such as major species composition, bulk density, and particle size distribution. Those results indicated a wide array of physical and chemical compositions that will be used to test various trace metal measurement techniques, with an emphasis on arsenic and selenium speciation. Among the measurements to be further studied by the Georgia Institute of Technology are particle morphology, molecular scale speciation, oxidation state, and mineralogy.

5
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EPRI
3420 Hillview Avenue, Palo Alto, California 94304-1338 • PO Box 10412, Palo Alto, California 94303-0813 USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com