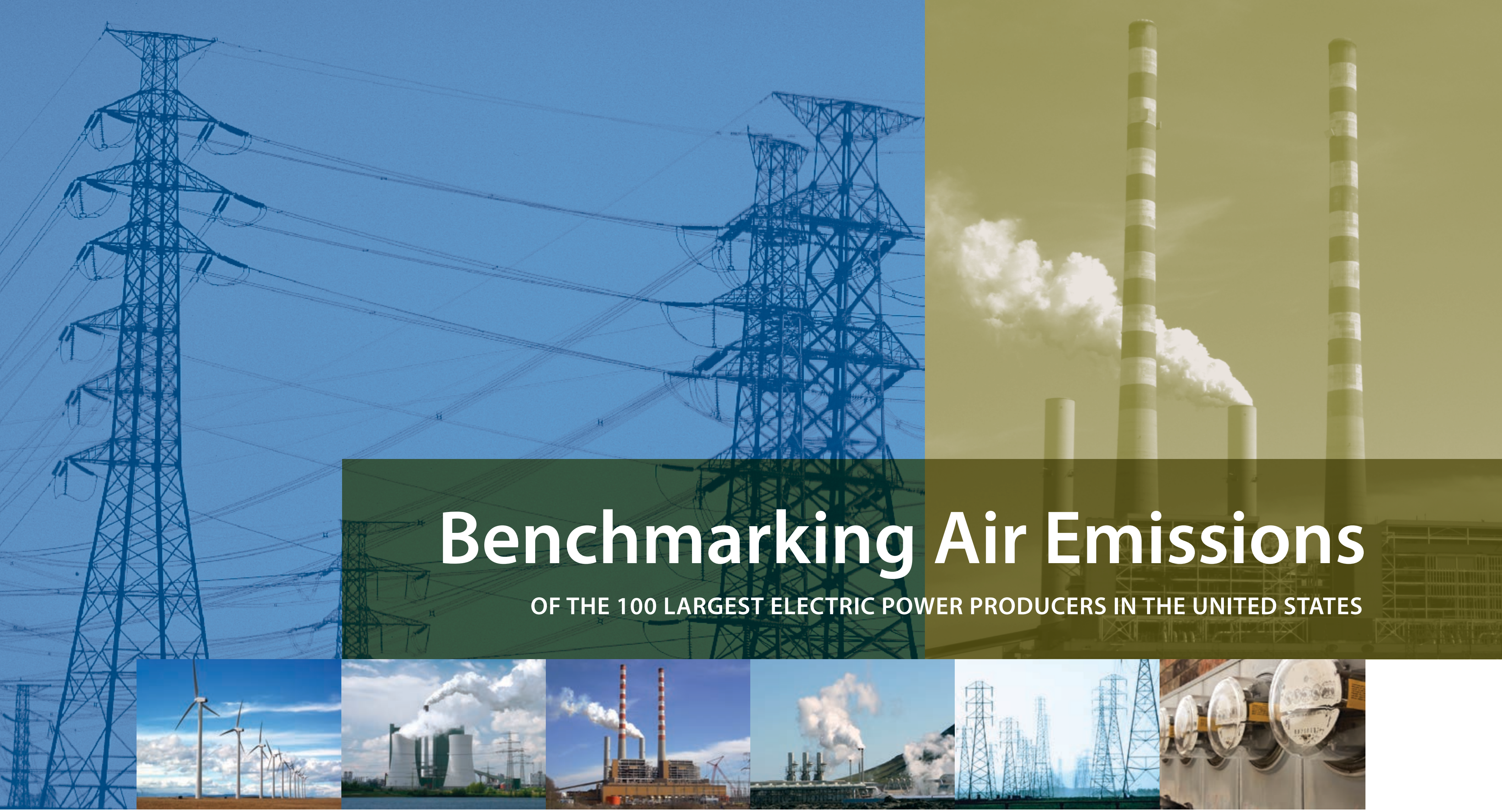

Benchmarking Air Emissions

OF THE 100 LARGEST ELECTRIC POWER PRODUCERS IN THE UNITED STATES

JULY 2012

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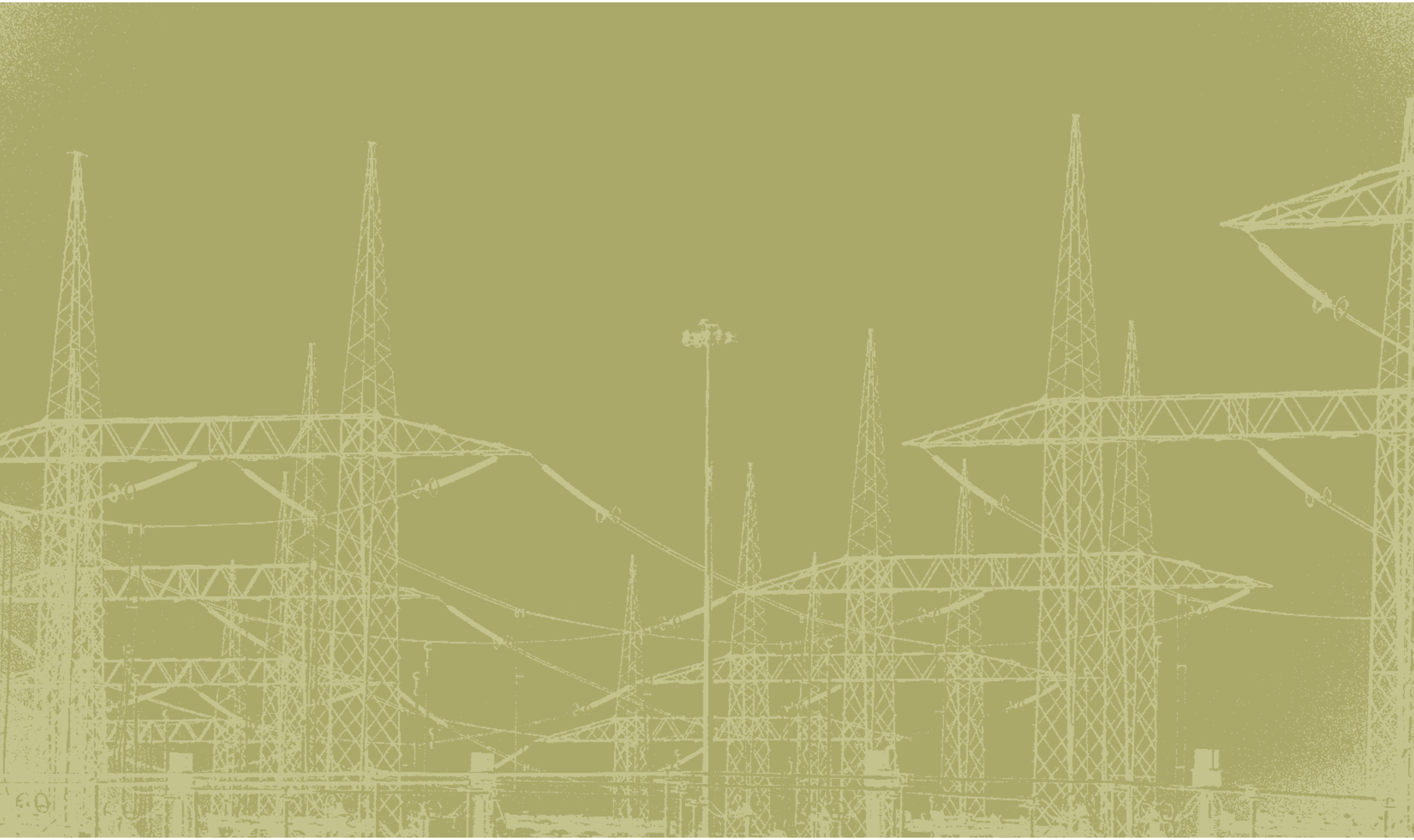

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Acknowledgments

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M. J. Bradley & Associates. (2012). *Benchmarking Air Emissions of the 100 Largest Electric Power Producers in the United States.*

Preface

The 2012 Benchmarking report is the eighth collaborative effort highlighting environmental performance and progress in the nation's electric power sector. The Benchmarking series began in 1997 and uses publicly reported data to compare the emissions performance of the 100 largest power producers in the United States. The current report is based on 2010 generation and emissions data. The report also includes analysis of 2011 emissions data, recognizing that the past few years have been a particularly active period in terms of companies switching to lower emitting fuels and installing pollution control systems.

Data on U.S. power plant generation and air emissions are available to the public through several databases maintained by state and federal agencies. Publicly- and privately-owned electric generating companies are required to report fuel and generation data to the U.S. Energy Information Administration (EIA). Most power producers are also required to report air pollutant emissions data to the U.S. Environmental Protection Agency (EPA). These data are reported and recorded at the boiler, generator, or plant level, and must be combined and presented so that company-level comparisons can be made across the industry.

The Benchmarking report facilitates the comparison of emissions performance by combining generation and fuel consumption data compiled by EIA with emissions data on sulfur dioxide (SO_2), oxides of nitrogen (NOx), carbon dioxide (CO_2) and mercury compiled by EPA; error checking the data; and presenting emissions information for the nation's 100 largest power producers in a graphic format that aids in understanding and evaluating the data. The report is intended for a wide audience, including electric industry executives, environmental advocates, financial analysts, investors, journalists, power plant managers, and public policymakers.

The report is available in PDF format on the Internet at http://www.ceres.org, http://www.nrdc.org, and http://www.mjbradley.com. Plant and company level data used in this report are available on the Internet at http://www.mjbradley.com.

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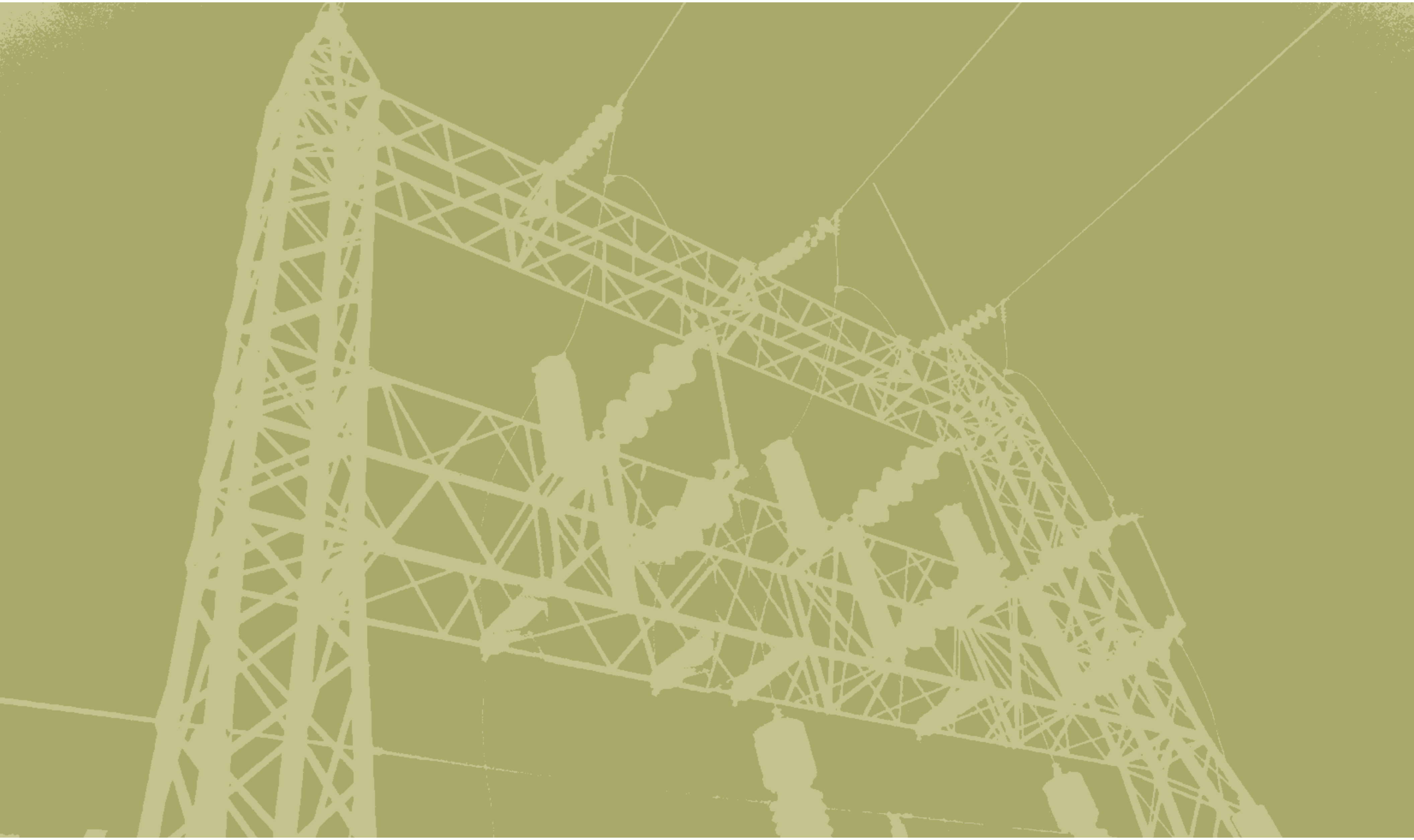


Executive Summary

This report examines and compares the air pollutant emissions of the 100 largest power producers in the United States based on their 2010 generation, plant ownership, and emissions data. The report also includes analysis of certain 2011 emissions data. Table ES.1 lists the 100 largest power producers featured in this report ranked by their total electricity generation from fossil fuel, nuclear, and renewable energy facilities. These producers include public and private entities[1] (collectively referred to as "companies" or "producers" in this report) that own roughly 2,500 power plants and account for 86 percent of reported electric generation and 88 percent of the industry's reported emissions.

TABLE ES.1

100 Largest Electric Power Producers in the U.S., 2010

RANK	PRODUCER NAME	2010 MWh (millions)	RANK	PRODUCER NAME	2010 MWh (millions)	RANK	PRODUCER NAME	2010 MWh (millions)	RANK	PRODUCER NAME	2010 MWh (millions)
1	Southern	198.0	26	Dynegy	38.6	51	Omaha Public Power District	15.9	76	Puget Holdings	11.2
2	AEP	174.1	27	Constellation	35.2	52	DPL	15.7	77	Iberdrola	11.1
3	NextEra Energy	165.7	28	PG&E	32.5	53	International Power	15.7	78	TransAlta	10.4
4	Duke	156.1	29	Westar	28.4	54	NiSource	15.5	79	Great River Energy	10.4
5	Exelon	152.7	30	Santee Cooper	27.9	55	US Power Generating Company	15.5	80	Austin Energy	10.4
6	Tennessee Valley Authority	143.9	31	Pinnacle West	26.8	56	JEA	15.4	81	UniSource	9.8
7	Entergy	126.5	32	Great Plains Energy	26.3	57	SUEZ Energy	15.0	82	Big Rivers Electric	9.7
8	Dominion	110.2	33	SCANA	26.1	58	IDACORP	14.4	83	ALLETE	9.7
9	Progress Energy	94.9	34	Salt River Project	25.8	59	Occidental	14.1	84	BP	9.6
10	MidAmerican	91.5	35	OGE	25.2	60	Los Angeles City	13.6	85	Buckeye Power	9.5
11	PPL	91.0	36	New York Power Authority	24.8	61	PNM Resources	13.4	86	Energy Northwest	9.4
12	Calpine	89.7	37	San Antonio City	22.5	62	Tri-State	13.4	87	CLECO	9.3
13	Edison International	82.7	38	CMS Energy	22.2	63	Tenaska	13.1	88	El Paso Electric	8.5
14	Ameren	76.5	39	Oglethorpe	22.0	64	Intermountain Power Agency	13.1	89	Hoosier Energy	8.5
15	Xcel	76.2	40	NV Energy	20.5	65	Municipal Elec. Auth. of GA	12.8	90	ArcLight Capital	8.4
16	FirstEnergy	75.3	41	Wisconsin Energy	20.5	66	Dow Chemical	12.7	91	PUD No 2 of Grant County	8.2
17	NRG	74.4	42	TECO	19.0	67	Energy Capital Partners	12.5	92	Grand River Dam Authority	7.8
18	Energy Future Holdings	73.2	43	Rockland Capital	18.6	68	NC Public Power	12.4	93	LS Power	7.7
19	PSEG	65.0	44	Associated Electric Coop	18.0	69	East Kentucky Power Coop	12.3	94	Chevron	7.7
20	US Corps of Engineers	64.4	45	EDF	17.9	70	Lower CO River Authority	11.9	95	PUD No 1 of Chelan County	7.7
21	DTE Energy	48.8	46	Alliant Energy	17.7	71	Seminole Electric Coop	11.7	96	International Paper	7.5
22	AES	44.4	47	NE Public Power District	17.5	72	Exxon Mobil	11.6	97	Sacramento Municipal Util Dist	7.3
23	US Bureau of Reclamation	41.2	48	Sempra	17.0	73	Portland General Electric	11.5	98	Avista	7.2
24	GenOn	41.2	49	General Electric	16.8	74	Arkansas Electric Coop	11.4	99	PowerSouth Energy Coop	7.0
25	Allegheny Energy	41.0	50	Basin Electric Power Coop	16.0	75	Integrys	11.3	100	TransCanada	6.9

The report focuses on four power plant pollutants for which public emissions data are available: sulfur dioxide (SO_2), oxides of nitrogen (NOx), mercury (Hg), and carbon dioxide (CO_2). These pollutants are associated with significant environmental and public health problems, including acid deposition, global warming, fine particle air pollution, mercury deposition, nitrogen deposition, ozone smog, and regional haze. The report benchmarks, or ranks, each company's absolute emissions and its emission rate (determined by dividing emissions by electricity produced) for each pollutant against the emissions of the other companies. In addition, this report calls attention to the opportunities and risks companies may face from potential changes in environmental regulations. Becoming aware of a company's exposure to these business opportunities and risks is the first step in developing effective corporate environmental strategies.

The electric power industry is in a period of transition. Natural gas prices have fallen dramatically, leading companies to rethink their investment choices, including whether to invest in upgrading older, fossil-fired power plants. Companies are choosing to retire a growing number of coal-fired generating plants over the coming decade. New environmental rules are forcing cuts in air pollution emissions. Renewable energy, distributed generation, and smart grid technologies are more widespread, forcing changes in the operations of the electric power system. This report examines some of the key trends that are reshaping the electric power sector; trends that will shape the emissions performance of the electric power fleet in future benchmarking reports.

The report also highlights the primary regulations related to air quality and climate change that the electric generating sector is facing. As these regulatory programs evolve, they will have a significant impact on electric generation in the U.S. by driving investment choices and, in conjunction with power market dynamics, encouraging uneconomical plants to retire. This analysis is intended to help inform policy and educate investors and companies on the key issues associated with the electric power industry.

Major Findings

Industry Trends

Natural gas continues to be the "big story" in the energy sector. Prices have fallen significantly from their peak in 2008, leading to increased natural gas use within the electric sector. Government data show that for the first time, since they started keeping records, electricity generation from natural gas-fired plants was virtually equal to the generation from coal-fired plants, with each fuel providing 32 percent of total generation in April 2012.

Since January 2010, plant owners have announced about 40 gigawatts (GW) of coal plant retirements or roughly 12 percent of the nation's coal-fired generating fleet due to changing market conditions, including low natural gas prices, and the costs associated with new environmental requirements.

Renewable energy and energy efficiency have shown increased growth and investment. Renewable energy production more than doubled from 83 million megawatt hours (MWh) in 2004 to 195 million MWh in 2011. Utility efficiency budgets have increased 26 percent from $5.4 billion in 2010 to $6.8 billion in 2011.

Electric Industry Emission Trends

Since 1990, power plant emissions of SO_2 and NOx have decreased and CO_2 emissions have increased.

- In 2010, power plant SO_2 and NOx emissions were both 68 percent lower than they were in 1990 due in large part to programs implemented under the 1990 Clean Air Act Amendments. SO_2 and NOx emissions have continued to decline in 2011 and 2012.
- In 2010, power plant CO_2 emissions were 24 percent higher than they were in 1990. Between 2009 and 2010, power plant CO_2 emissions increased by 5 percent, and total U.S. greenhouse gas emissions increased by over 3 percent. This increase is primarily due to economic growth resulting in increased energy consumption across all sectors, and much warmer summer conditions resulting in an increase in electricity demand for air conditioning that was generated primarily by combusting coal and natural gas. CO_2 emissions from power plants are largely unregulated at

the federal level. There are greenhouse gas permitting requirements for new or modified power plants and EPA has proposed national emissions standards for new fossil fuel-fired power plants; however, no standards have been proposed for existing facilities. Preliminary data from 2011 indicate that CO_2 emissions declined by about 5 percent in 2011. This is in large part due to a shift away from coal—between 2010 and 2011 coal based electricity production fell by more than 6 percent. At the same time, record low natural gas prices and a higher than average snowpack in the Pacific Northwest drove the national shares of natural gas and hydroelectric power generation up by 3 percent and 25 percent, respectively.

- Power plants have only recently begun to report their mercury emissions; therefore, long-term emissions trends are not available.

Overall Emissions from Electricity

The electric industry in the U.S. is a major source of air pollution.

- In 2010, power plants were responsible for about 64 percent of SO_2 emissions, 16 percent of NOx emissions, 68 percent of mercury air emissions (among sources reporting to EPA's Toxics Release Inventory), and 40 percent of CO_2 emissions in the U.S.
- The electric industry accounts for more CO_2 emissions that any other sector, including the transportation and industrial sectors.

Air Pollution Rankings and Comparisons

The 100 largest power producers generated 86 percent of electric power in the U.S. in 2010. The 100 largest producers generated 97 percent of all nuclear power, 90 percent of all coal-fired power, 82 percent of all hydroelectric power, 78 percent of all natural gas-fired power, and 62 percent of all non-hydroelectric renewable power.

Air pollution emissions from power plants are highly concentrated among a small number of producers. For example, a quarter of the electric power industry's SO_2 and CO_2 emissions are emitted by just three and five top 100 producers, respectively. Figure ES.1 summarizes the distribution of emissions among electric power producers.

Electric power producers' emission levels and emission rates vary significantly due to the amount of power produced, the efficiency of the technology used in producing the power, the fuel used to generate the power, and installed pollution controls. In 2010, total generation among the 100 largest power producers ranged from 6.9 million MWh to 198 million MWh and:

- SO_2 emissions ranged from 0 to 498,009 tons, and SO_2 emission rates ranged from 0 pounds per MWh to 11.4 pounds per MWh;
- NOx emissions ranged from 0 to 129,951 tons, and NOx emission rates ranged from 0 pounds per MWh to 4 pounds per MWh;
- CO_2 emissions ranged from 0 to 155 million tons, and CO_2 emission rates ranged from 0 pounds per MWh to 2,361 pounds per MWh.
- Mercury emissions from producers with coal plants ranged from less than 1 to 6,398 pounds, and mercury emission rates ranged from 0.0001 pound per gigawatt hour (GWh; a GWh is 1,000 MWh) to 0.13 pound per GWh.

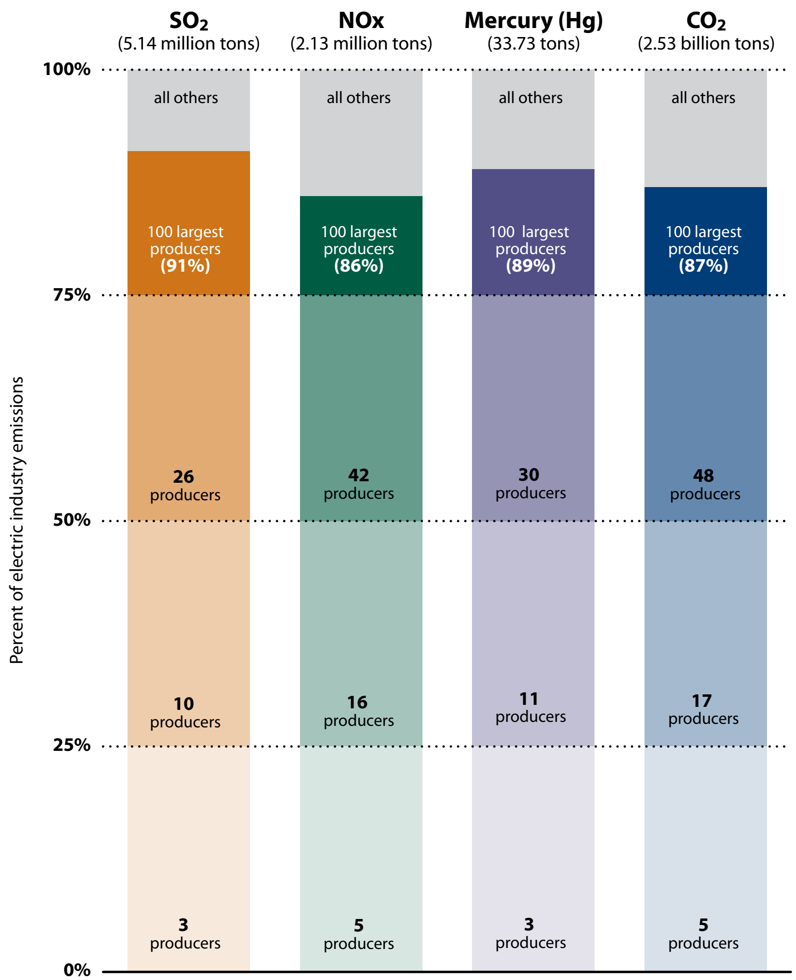
Using this Report

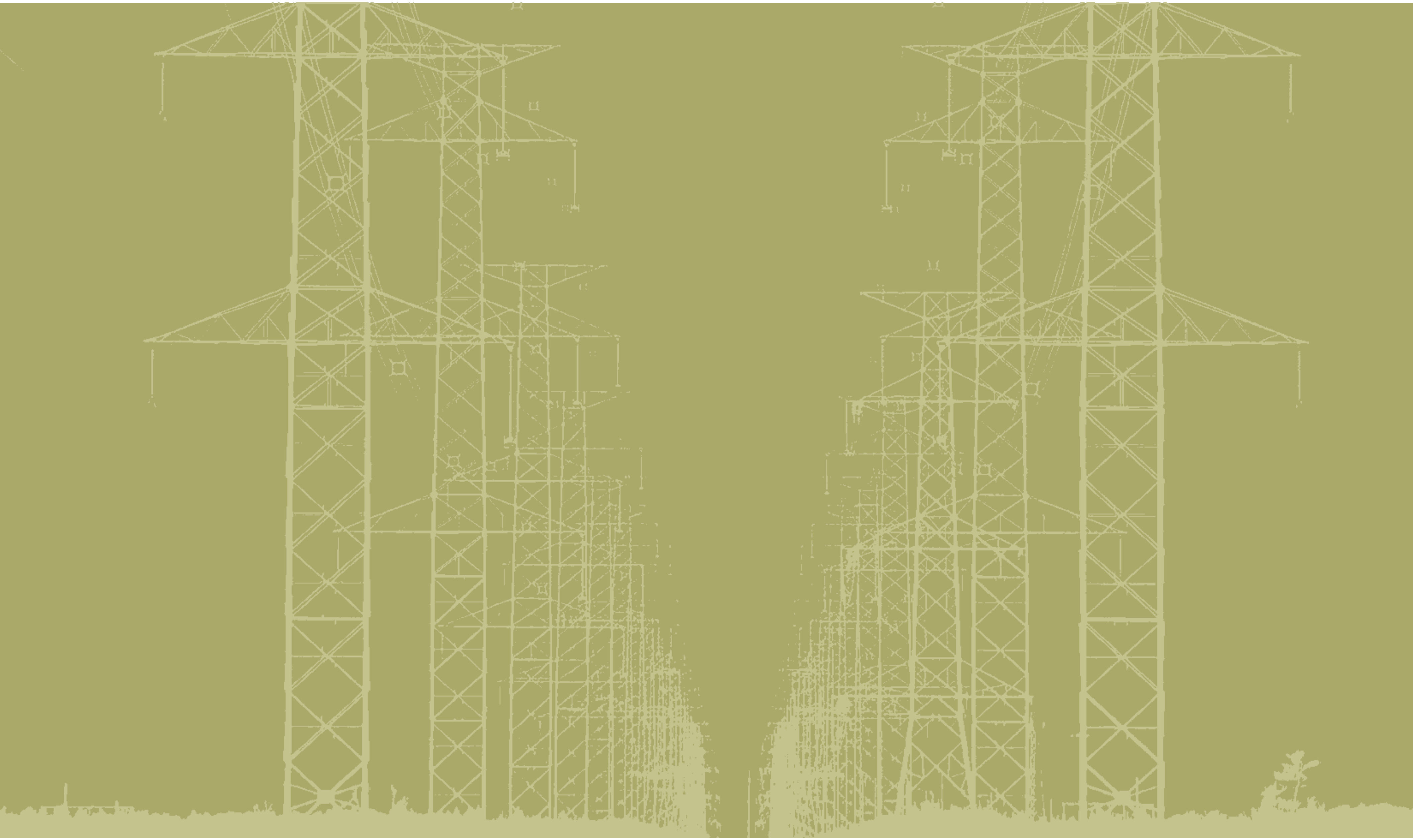
The information in this report supports informed decision-making in several areas:

- It can be used by policymakers who are addressing the public health and environmental risks of SO_2, NOx, mercury, and CO_2 emissions.
- It can be used by the investment community to assess the costs and business risks associated with compliance with future additional emission reduction requirements.
- It can be used by electric power companies and the public to assess corporate performance relative to key competitors, prior years, and industry benchmarks.

FIGURE ES.1

Concentration of Air Emissions among All Electric Power Producers





Electric Industry Overview

Electric power production is essential to the growth and operation of the U.S. economy. The availability, reliability, and price of electricity have significant impacts on national economic output, energy security and quality of life. At the same time, the production of electricity from fossil fuels results in air pollution emissions that affect both public health and the environment.

This report focuses on four power plant pollutants for which public emissions data are available: sulfur dioxide (SO_2), nitrogen oxides (NOx), mercury, and carbon dioxide (CO_2). Collectively, power plants are responsible for about 64 percent of SO_2 emissions, 16 percent of NOx emissions, 68 percent of mercury air emissions (among sources reporting to EPA's Toxics Release Inventory), and 40 percent of CO_2 emissions in the U.S.[2] The electric power industry accounts for more CO_2 emissions that any other sector, including the transportation and industrial sectors.

SO_2 and NOx emissions from power plants both contribute to acid rain, regional haze, and fine particle air pollution. Acid rain damages trees and crops, acidifying soils, lakes, and streams. Fine particle air pollution can affect the heart and lungs through inhalation. Exposure to fine particle air pollution is linked to premature death and illness from respiratory disease and other ailments, particularly in children and the elderly. Regional haze impairs visibility, most notably at national parks. NOx emissions are also associated with nitrogen deposition and ground-level ozone. Nitrogen deposition can impair water quality by overloading a water body with nutrients. Ground-level ozone can also trigger serious respiratory problems.

Mercury air emissions from power plants deposited to lakes, ponds, and oceans are converted by certain microorganisms to a highly toxic form of the chemical known as methylmercury. Methylmercury then accumulates in fish, shellfish, as well as birds and mammals that feed on fish. Humans are exposed to mercury when they eat contaminated fish. Exposure to high levels of methlymercury is detrimental to the development of fetuses and young children.

FIGURE 1

U.S. Electric Industry Contribution to Total Emissions

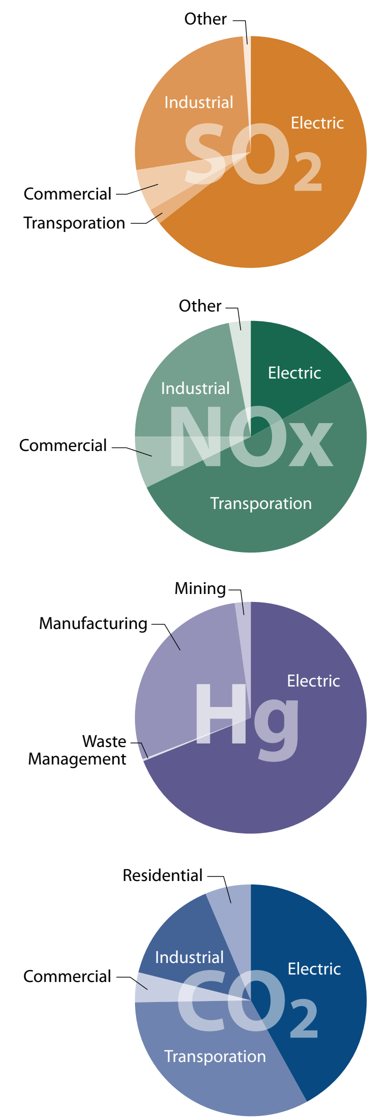
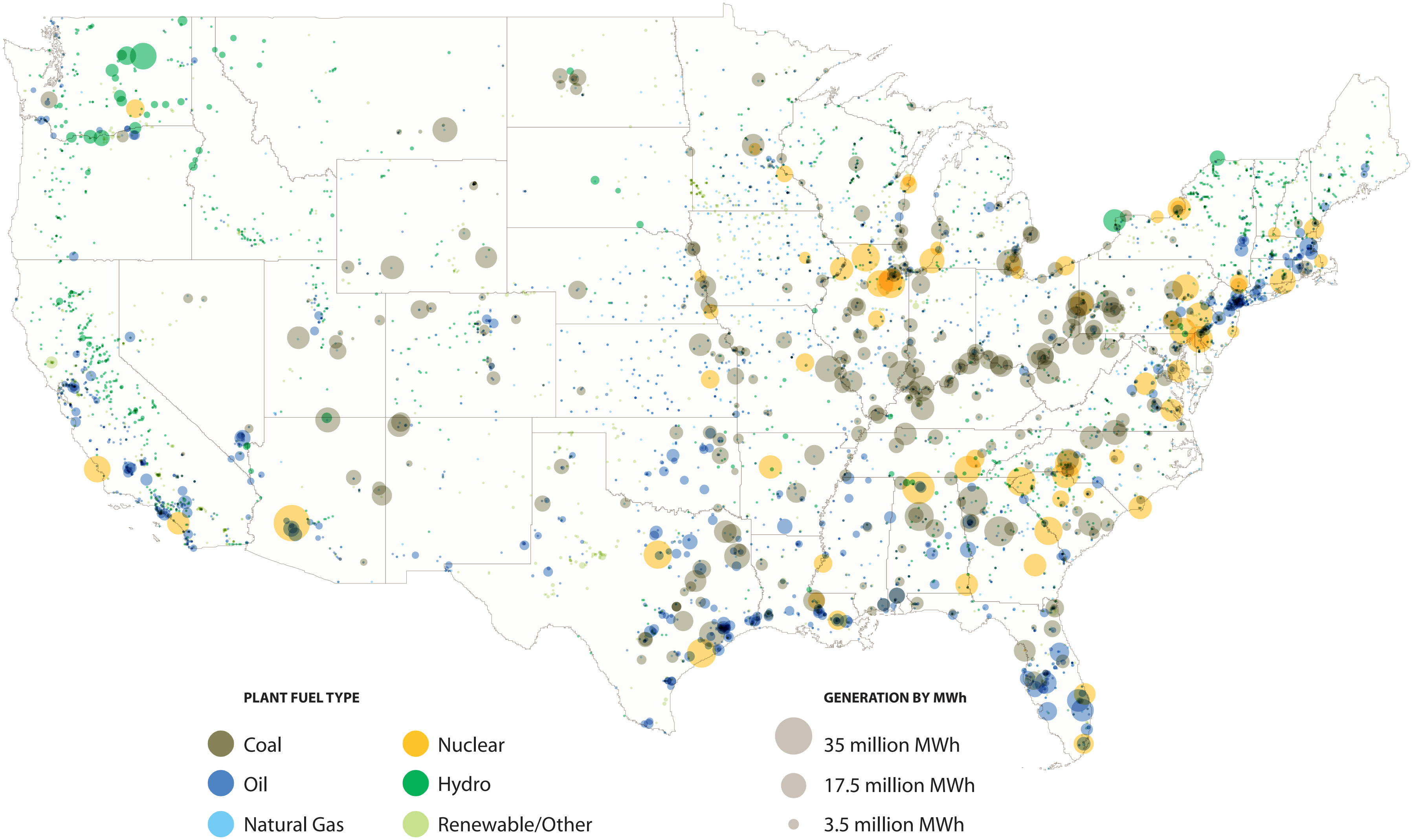


FIGURE 2

Location and Relative Size of U.S. Power Plants by Fuel Type



SOURCE: MJB&A ANALYSIS; VENTYX VELOCITY SUITE; U.S. ENERGY INFORMATION ADMINISTRATION: FORM EIA-923 (2010).

CO_2 is the most prevalent of anthropogenic (or human caused) greenhouse gas emissions. Greenhouse gases (or global warming pollutants) trap heat in the atmosphere and at elevated concentrations lead to global climate change. Climate change threatens public health due to more severe heat waves, exacerbation of ground-level ozone formation, and increases in extreme weather, such as floods and droughts.

Because of their associated public health and environmental risks, SO_2, NOx, mercury, and now greenhouse gases, are regulated under the Clean Air Act.

Sources of Power

Over 5,800 power plants generate electricity in the U.S. In 2010, these plants generated approximately 4.1 billion MWh of electricity. About 69 percent of this power was produced by burning fossil fuels (coal, natural gas, and oil) resulting in the release of SO_2, NOx, mercury, and CO_2 into the air. Coal accounted for 45 percent of total power production, and the remaining fossil fuels—natural gas and oil—accounted for 24 percent and 1 percent, respectively. Nuclear power, the largest non-fossil fuel energy source, generated 20 percent of U.S. electric power. Hydroelectricity accounted for about 6 percent of total power production and non-hydroelectric renewables (such as wind turbines and solar photovoltaic cells) accounted for almost 3 percent. A variety of other fuel sources comprised the remaining 2 percent of generation.[3]

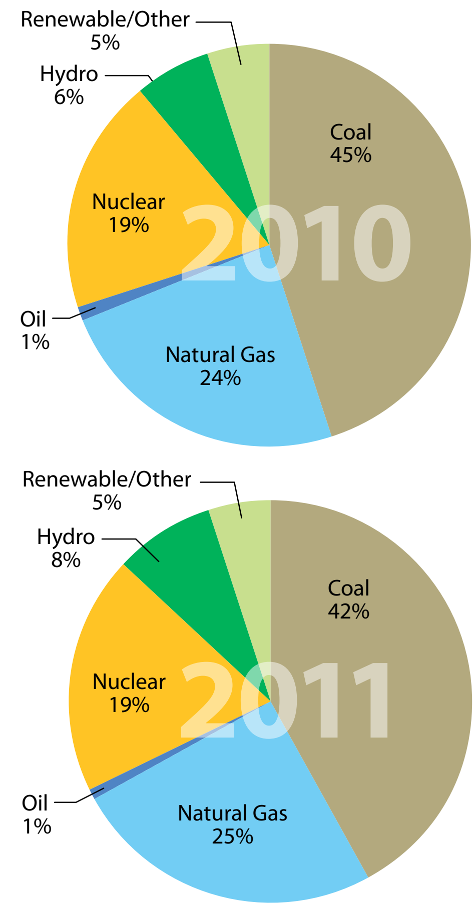
Coal-fired power plants are located across the nation, most predominantly in the midwestern and eastern parts of the country, with the heaviest concentrations of coal plants located along the Ohio and Mississippi Rivers. Natural gas plants are generally smaller than coal plants and are also spread across the country. The heaviest concentrations of natural gas-fired power plants are in Texas and Louisiana, near the Gulf of Mexico, and in California. Most large nuclear plants are located in eastern and upper-midwestern states, and most large hydroelectric facilities are in northwestern states.

Figure 2 plots the locations of the nation's major power plants, sized according to their electricity production in 2010 and colored based on their primary fuel type.

Power plant development in the U.S. has occurred in cycles with a dramatic spike in natural gas-fired power plant construction in the period from 2000-2005. Most coal-fired power plants were

FIGURE 3

U.S. Electricity Generation by Fuel Type (2010 and 2011)

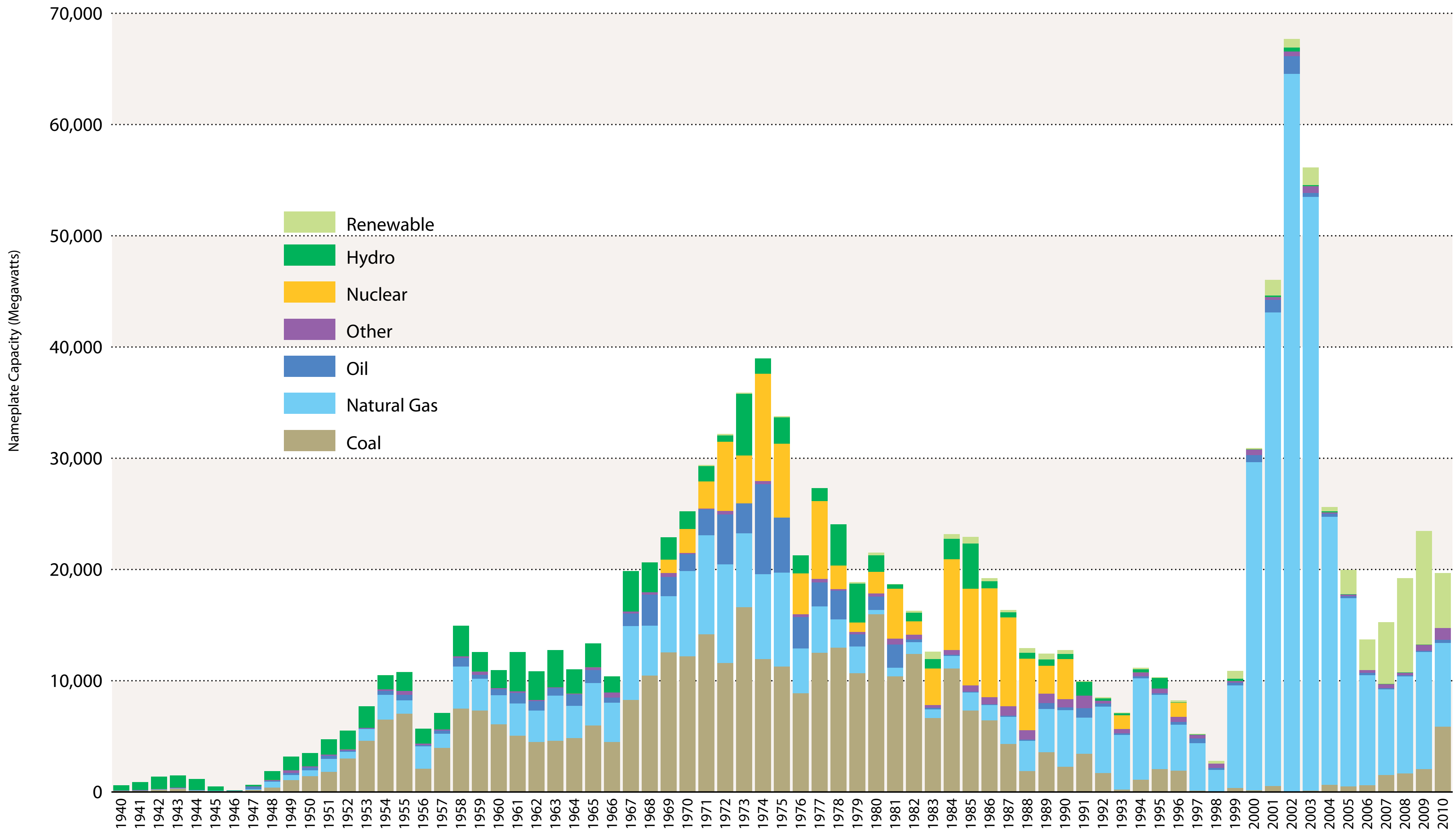


Historically, coal has accounted for the largest share of U.S. power generation (≈40 to 50 percent). However, in July 2012, the U.S. Energy Information Administration announced that for the first time, since they started keeping records, electricity generation from natural gas-fired plants was virtually equal to the generation from coal-fired plants, with each fuel providing 32 percent of total generation in April 2012.

SOURCE: U.S. ENERGY INFORMATION ADMINISTRATION. SHORT-TERM ENERGY OUTLOOK AND TODAY IN ENERGY. JULY 2012.

FIGURE 4

U.S. Electric Generating Capacity by In Service Year



SOURCE: U.S. ENERGY INFORMATION ADMINISTRATION. ANNUAL ELECTRIC GENERATOR REPORT: FORM EIA-860 (2010).

built before 1980. There was a wave of nuclear plant construction from the late 1960s to about 1990. Since 2005 some new coal-fired plants have come on-line, but most new capacity has been natural gas fired, with a significant amount of renewable energy technologies. Figure 4 presents the in service year and fuel type of the existing electric generating fleet in the U.S.

Electricity prices vary across the U.S. depending in part on the mix of power plants available in the region. Coal-fired pow d power plant would increase more than other fossil fuel-fired technologies if CO_2 were regulated and companies had to pay for their carbon emissions.

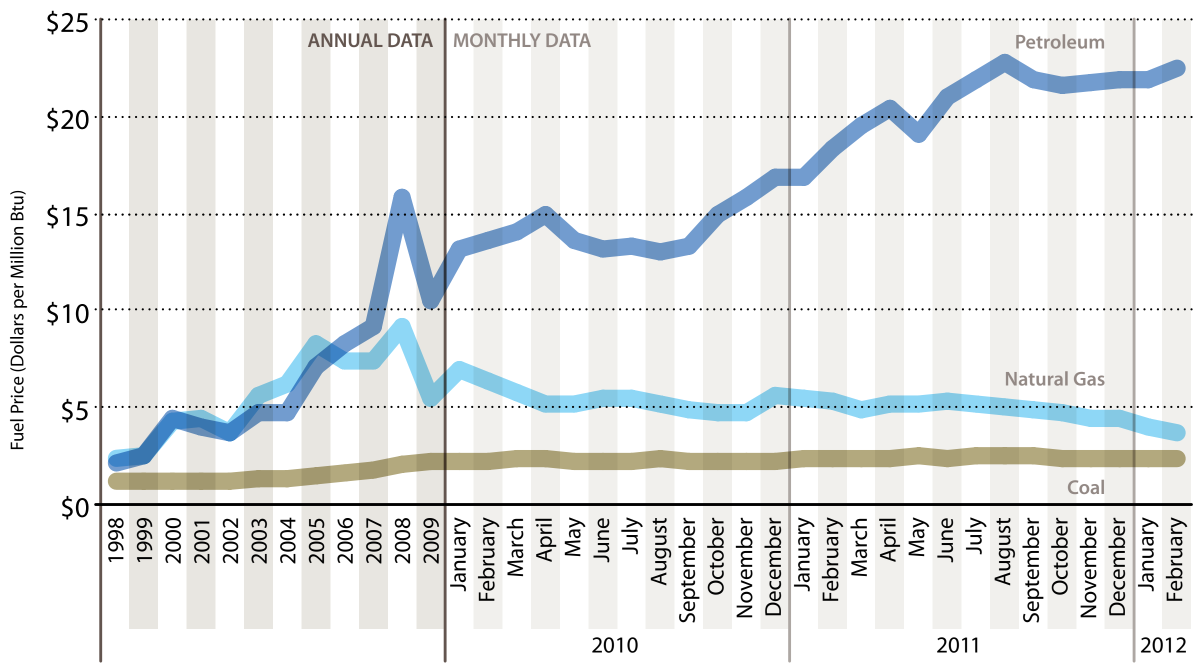
Market Trends

The electric power industry is in a period of transition with many of the market trends that were outlined in the 2010 Emissions Benchmarking report continuing to shape the industry. In particular, natural gas prices have continued to fall from their peak in 2008, leading to increased natural gas use within the electric sector. Southern Company, for example, historically one of the nation's largest users of coal, expects to consume more natural gas than coal in 2012 for the first time in its 100-year history.[4] This shift in fuel price dynamics is leading companies to rethink some of their investment choices, including whether to invest in upgrading older, fossil-fired power plants.[5]

The following discussion highlights some of the key issues facing the electric power sector, including implications for future emissions trends.

FIGURE 5

Costs of Fuels for Electricity Generation: 1998 through February 2012



SOURCE: U.S. ENERGY INFORMATION ADMINISTRATION, ELECTRIC POWER ANNUAL 2010 DATA TABLES: TABLE 3.5. RECEIPTS, AVERAGE COST, AND QUALITY OF FOSSIL FUELS FOR THE ELECTRIC POWER INDUSTRY, 1999 THROUGH 2010. RELEASED NOVEMBER 9, 2011.

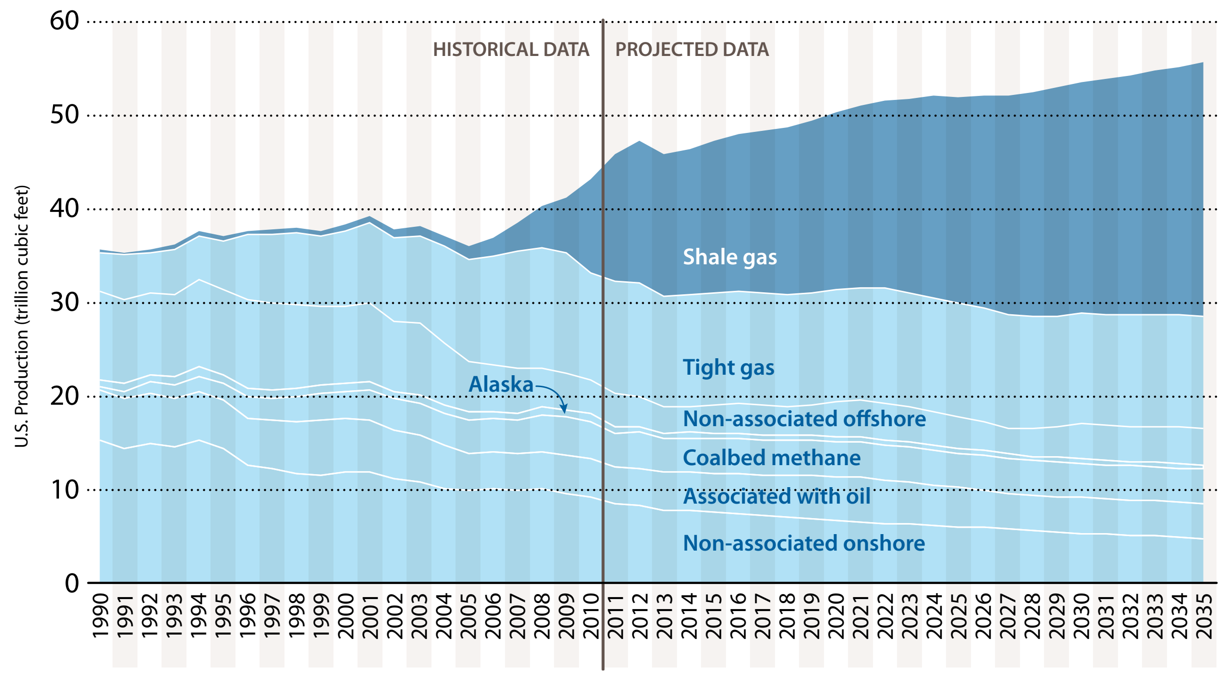
Natural Gas Outlook

Electricity prices tend to reflect trends in fuel prices—particularly natural gas prices, because natural gas-fired power plants set the market price of electricity around much of the U.S., and fuel costs account for a majority of generators' variable costs of generation. Henry Hub natural gas prices were hovering around $2.50 per million British thermal units (mmBtu) in May 2012, and NYMEX natural gas futures contracts had recently dipped to their lowest levels in over 10 years.[6,7] Sustained, low natural gas prices have encouraged the increased use of natural gas within the electric power sector. On average, over the past decade, natural gas consumption by the electric power sector has increased at a rate of four percent per year (see Figure 7). Energy analysts are predicting that natural gas prices will increase somewhat from current levels, but continue to remain relatively low by historic standards due to robust domestic production.[8]

The United States has large reserves of natural gas and almost 90 percent of the natural gas consumed in the U.S. is produced domestically from both onshore and offshore drilling. Technological advances in horizontal drilling and hydraulic fracturing have allowed access to large volumes of shale gas that were previously uneconomical to produce. Shale gas refers to natural gas that is trapped within shale formations or fine-grained sedimentary rocks. Figure 6 shows the EIA projection of natural gas production in the U.S. The chart highlights the rapid growth in natural gas production over the past few years and the expectations of further growth over the coming decade. The chart also highlights the expanding role of shale gas in the nation's energy supply mix. States such as Pennsylvania and Arkansas have

FIGURE 6

U.S. Natural Gas Production: 1990-2035 (Historic and Projected)



SOURCE: U.S. ENERGY INFORMATION ADMINISTRATION, AEO2012 EARLY RELEASE OVERVIEW, JANUARY 23, 2012.

seen large increases in natural gas production. For example, Pennsylvania's natural gas production more than quadrupled between 2009 and 2011.[9]

Shale gas production through hydraulic fracturing has garnered significant attention due to concerns about potential drinking water contamination, air pollution emissions (including emissions of methane, which is a powerful global warming pollutant), and industrialization of areas with no previous history of large scale energy production. EPA has recently issued regulations to reduce air pollution emissions from new natural gas wells,[10] and a task force appointed by President Obama has been charged with coordinating federal oversight of domestic natural-gas development while protecting public health and safety.[11] Several states are also considering new regulations of hydraulic fracturing.

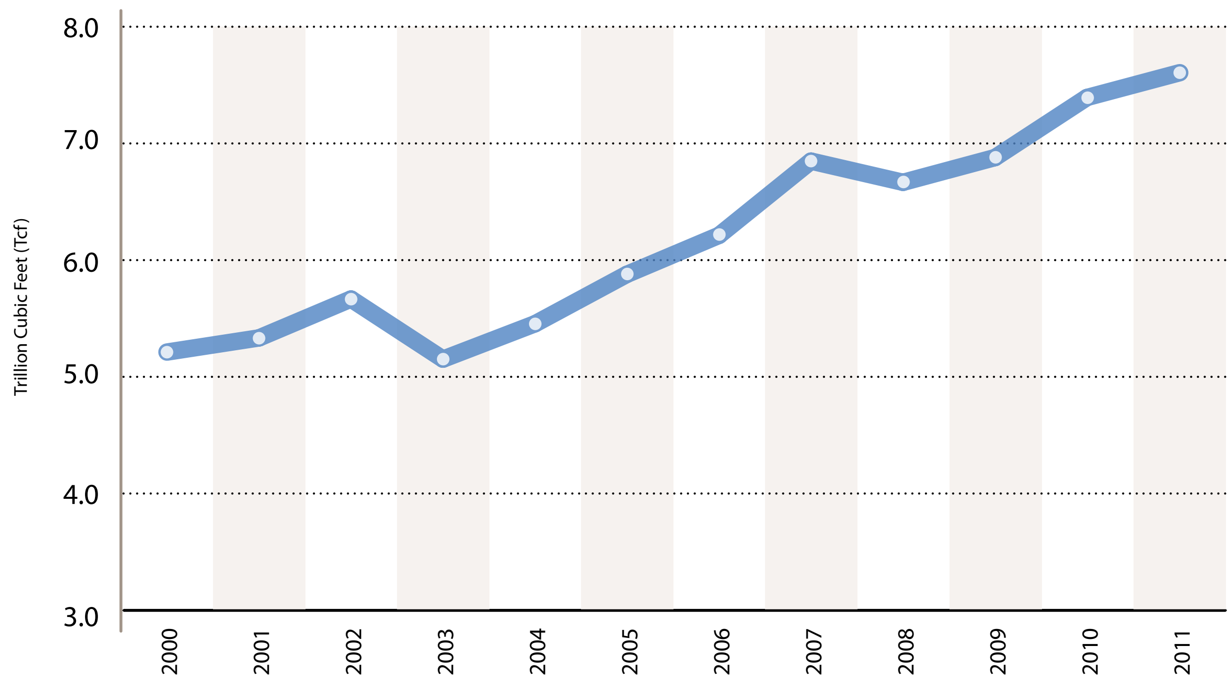
Coal Plant Retirements

Electricity producers have announced a growing number of coal plant retirements over the past several years due to changing market conditions and costs associated with new environmental requirements.

Since January 2010, plant owners have announced about 40 GW of coal plant retirements or roughly 12 percent of the nation's coal-fired generating fleet.[12] Most of the plant closures are scheduled to occur between 2012 and 2020; some have already been completed. In general, the affected units are small, old, and lack advanced pollution control equipment.[13] Figure 8 shows the geographic distribution of the announced coal plant retirements. Half of the planned retirements are located in Ohio, Virginia, West Virginia, Pennsylvania, and Indiana. Also, most of the planned retirements

FIGURE 7

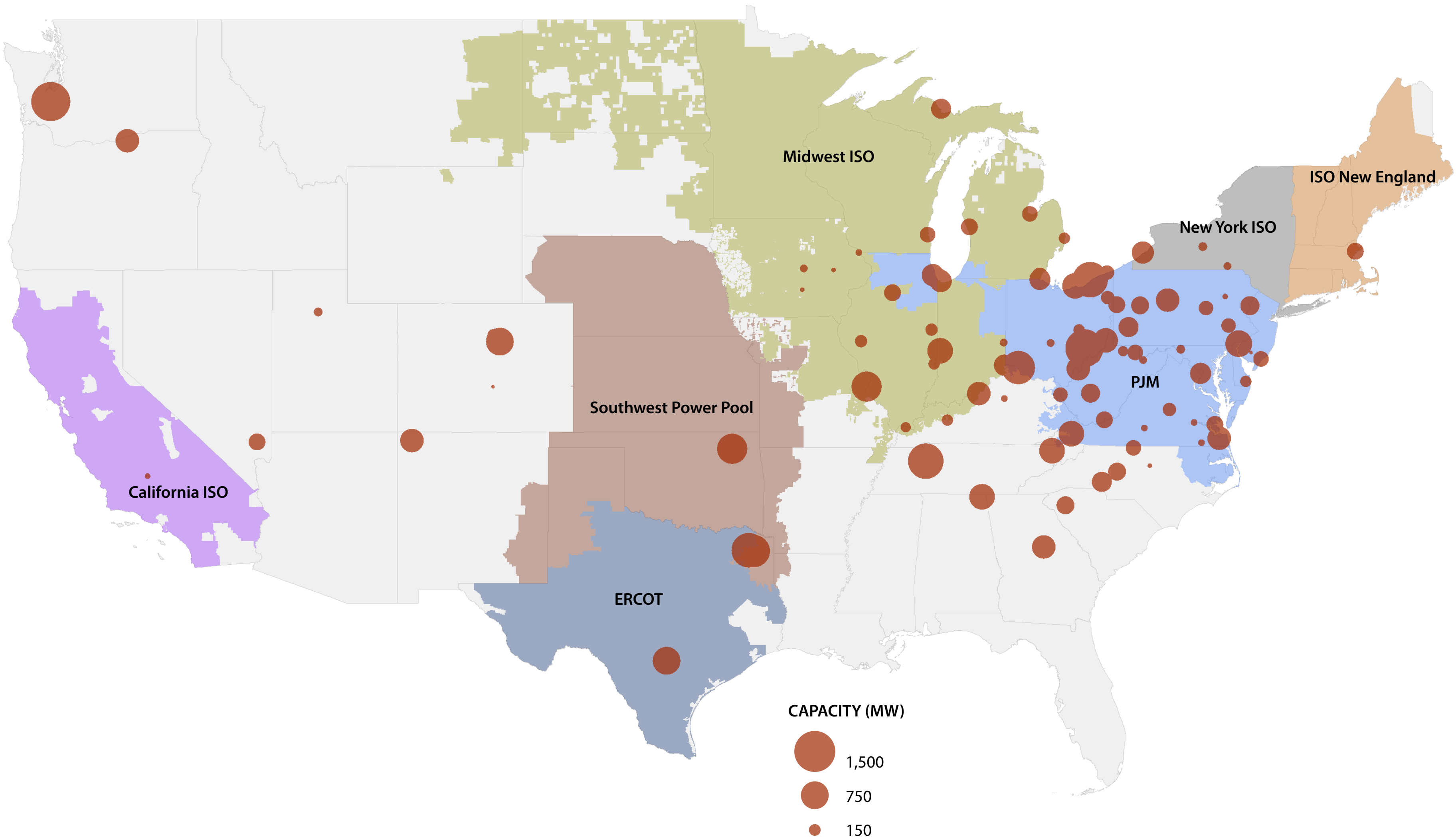
Natural Gas Deliveries to Electric Power Producers: 2000-2011



SOURCE: U.S. ENERGY INFORMATION ADMINISTRATION, NATURAL GAS CONSUMPTION BY END USE. U.S. NATURAL GAS DELIVERIES TO ELECTRIC POWER CONSUMERS: 2000-2011. RELEASED APRIL 30, 2012.

FIGURE 8

Announced Coal Unit Retirements (Since January 2010)



SOURCE: MJB&A ANALYSIS; VENTYX VELOCITY SUITE.

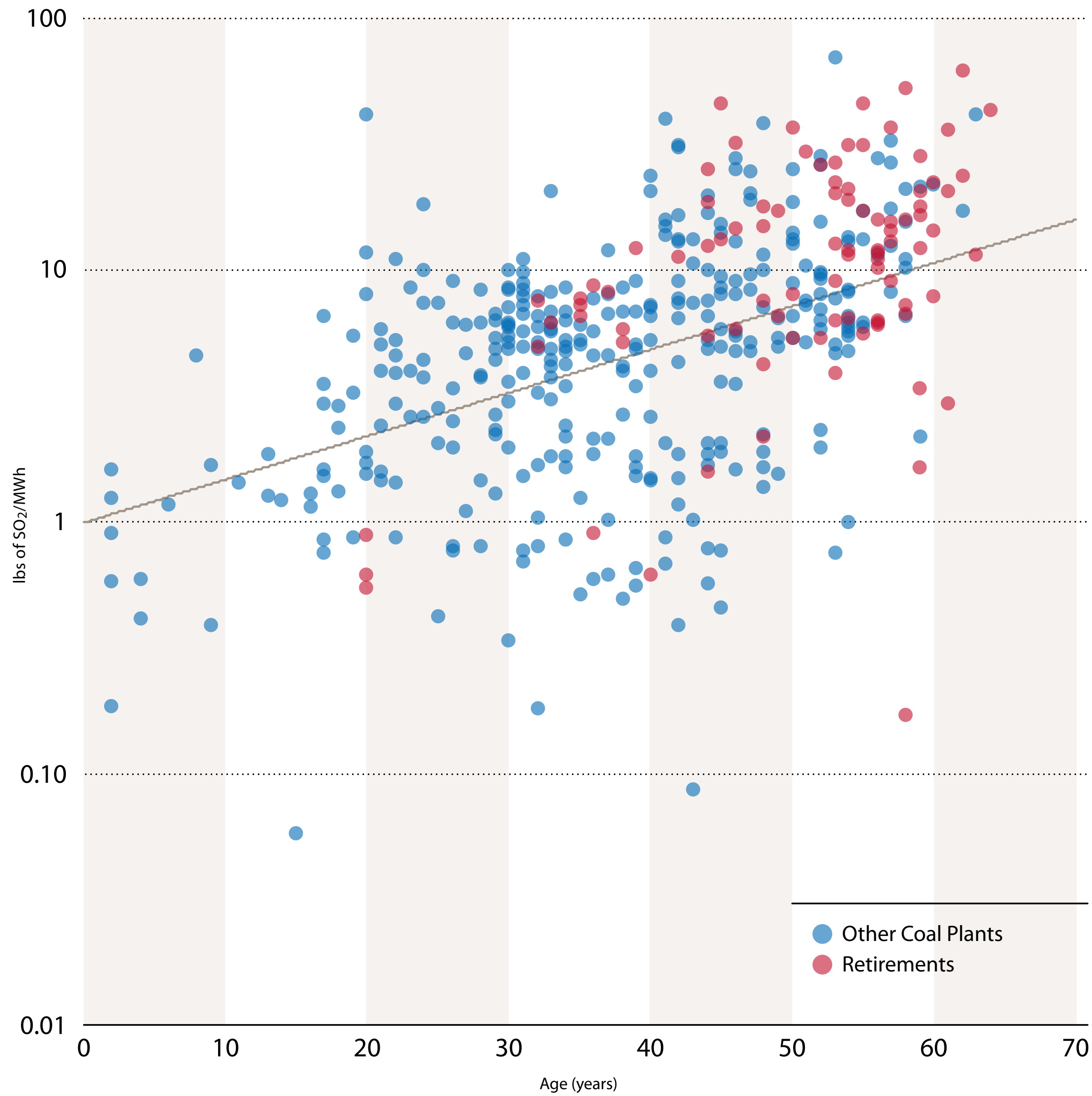
are concentrated among a small number of companies. AEP, FirstEnergy, GenOn, Duke, TVA, and Dominion account for about 60 percent of announced retirements.

In general, older generating facilities tend to have higher emissions rates for pollutants like NOx and SO_2 because they tend to lack advanced pollution control systems. Figure 9 plots the average SO_2 emissions performance of the nation's coal-fired generating units, distinguishing between units that have (and have not) been announced for retirement. The chart shows that the retiring units are generally older and higher emitting.

Companies cite a variety of factors in their decisions to retire: (1) lower natural gas prices, which in turn translate to lower wholesale electricity prices; (2) rising coal prices; (3) lower demand for electricity; and (4) the costs associated with new environmental requirements.[14] In contrast to the steady increase in natural gas-fired generation, coal-fired generation fell by 21 percent between December 2010 and December 2011.[15] Between 2005 and 2008, when natural gas prices were at their peak, the United States was consuming about 1,122 million tons of coal per year.[16] In 2011, consumption had fallen to 1,003 million tons—an 11 percent reduction.[17]

FIGURE 9

Coal Generating Units: SO_2 Emission Rates and Unit Age
(units in red have been announced for retirement)



Renewable Energy Outlook

Renewable energy (excluding large hydroelectric projects) accounted for nearly 5 percent of U.S. electricity generation in 2011.[18] Renewable energy production more than doubled from 83 million MWh in 2004 to 195 million MWh in 2011.[19]

Wind energy, in particular, has been rapidly expanding over the past several years. In 2011, the U.S. wind energy industry added over 6,800 megawatts (MW) of new wind power capacity, bringing the nation's cumulative total to over 47,000 MW.[20] Beneath the large increase in total installed capacity, stark regional variations remain. High wind capacity in the ERCOT (Texas), Colorado, and the Midwest ISO areas have led to record high contributions by wind to the total grid mix; Xcel Energy, for example, reported greater than 50 percent of its total Colorado load being served by wind in early 2012. System operators have been forced to adjust market operations to account for the variability of wind and the prominent role it now plays in these regions. On the other hand, resource and incentive limitations in the southeast have left wind penetration levels virtually unchanged.

Solar energy has also been rapidly expanding. Although a number of companies have planned or started utility scale projects, projects less than 6 MW (below utility scale) account for a large share of capacity added, owing to shorter development times and ease of interconnection. Several utility-scale developments have run into technical or financing hurdles.

The key question for the renewable energy sector is what incentives will be available in the U.S. after 2012. The

Construction of the Endeavor Wind Energy Centers in northwestern Iowa.
PHOTO CREDIT: NEXTERA ENERGY RESOURCES

production tax credit (PTC) for wind energy is set to expire at year's end and needs Congressional action to be extended. After several years of steep growth, market players anticipate a relatively modest 2 GW of wind capacity additions in 2013 without continued incentives. Momentum at the state level is mixed. Several governors have expressed interest in reducing or eliminating renewable portfolio standards (RPSs). In other states, interconnection limits and the technical challenges of integrating variable renewables present additional hurdles. However, a number of states have implemented innovative incentives including a green bank and feed-in tariffs.

Energy Efficiency Outlook

Energy efficiency is widely recognized to be a low cost energy resource that reduces emissions by avoiding the need for additional energy production. According to the American Council for an Energy-Efficient Economy, utilities can generate electricity savings at a cost of 2.5 cents per kilowatt hour (KWh).[21] Results from energy efficiency programs have confirmed this. ISO New England reports average costs ranging from 2 to 4 cents per KWh through energy efficiency programs in New England states.[22] The average retail price of electricity in the U.S. is about 10 cents per KWh.

Ratepayer-funded energy efficiency program budgets throughout the United States have increased between 2010 and 2011. Utility companies employ programs such as efficiency audits, discounts on energy efficient equipment, rebates to consumers, and financial assistance to companies engaged in energy saving projects in order to encourage energy savings. Electricity efficiency budgets have increased 26 percent from $5.4 billion in 2010 to $6.8 billion in 2011.[23] New York had the largest absolute budget increase of $495 million. Arkansas had the largest percentage increase (767 percent). California continues to rank first in the nation with the largest budget in 2011: $1.5 billion.[24] Together, California, New York, Massachusetts, and Florida accounted for 50 percent (or $3.4 billion) of the total electric energy efficiency budgets in the United States.[25] Efficiency programs were estimated to have generated 112.5 million MWh of electric energy savings in 2010.[26] That is roughly equivalent to the total amount of electricity consumed in Virginia in 2010.

In competitive power markets, market operators have been encouraging an expanded role for energy efficiency. In PJM, for example, the nation's largest wholesale power market, energy efficiency competes with generating facilities to meet the region's future capacity needs. Energy efficiency resources that exceed current building codes or appliance standards are eligible to participate in the region's forward capacity auction. More than 900 MW of energy efficiency resources cleared the auction in 2012, making them eligible for capacity payments.[27]

States have also been encouraging expanded investment in energy efficiency. As of 2011, 24 states have established energy efficiency resource standards (EERS) which require utility companies to reduce their customer's energy use through energy efficiency measures.[28] Some of the strongest energy efficiency standards have been adopted by Vermont and Massachusetts, which require around 2.5 percent savings annually.[29] States have also worked to address utilities' disincentives to invest in energy efficiency through decoupling mechanisms—where utility sales are separated from their revenues and profits.

Environmental Regulatory Trends

The electric generating sector currently faces numerous regulations related to air quality and climate change. As detailed in this report, fossil fuel-fired power plants, particularly coal-fired power plants, are a significant source of SO_2, NOx, CO_2, mercury, and other hazardous air pollutants. These power plant emissions are controlled through several statutory and regulatory programs. As these regulatory programs continue to evolve, they will have important implications for public health, for the mix of U.S. generating resources, and for economic growth by driving investment in new and cleaner technologies and encouraging some of the more inefficient and higher polluting plants to retire. The discussion below provides a snapshot of the major environmental regulatory programs facing the electric generating sector.

Mandatory Reporting of Greenhouse Gases

Pursuant to existing EPA authority under Clean Air Act Sections 114 and 208, as well as direction included in the Fiscal Year 2008 Consolidated Appropriations Act, all major stationary sources of greenhouse gas emissions, including power plants, must report their greenhouse gas emissions beginning January 1, 2010. The first annual reports for the largest emitting facilities, covering calendar year 2010, were submitted to EPA on March 31, 2011. The program is expected to eventually cover approximately 85 percent of the nation's greenhouse gas emissions and apply to approximately 10,000 facilities.

Regulation of Greenhouse Gases under the Clean Air Act

On December 7, 2009, EPA signed the greenhouse gas endangerment finding in response to the U.S. Supreme Court's 2007 decision in Massachusetts v. EPA. In response to the Court's decision, EPA has made an official determination that greenhouse gas emissions endanger public health and welfare within the meaning of Section 202(a) of the Clean Air Act. This decision in turn set the stage for EPA to establish the first-ever federal vehicle emissions standards for greenhouse gases, following the Agency's simultaneous finding that vehicle greenhouse gas emissions cause or contribute to global warming. EPA has finalized emissions standards for new light-duty motor vehicles (in coordination with Department of Transportation fuel economy standards) in 2010, and standards for medium- and heavy-duty vehicles in 2011. Additionally, on May 13, 2010, EPA issued its final "Tailoring Rule" setting the thresholds for air permitting requirements for large stationary sources of greenhouse gas emissions under the so-called Prevention of Significant Deterioration (PSD) and Title V permitting requirements of the Clean Air Act. PSD is a preconstruction permitting program under the Clean Air Act that requires companies to install pollution control systems when constructing a new facility or when undertaking a major upgrade at an existing facility that significantly increases emissions.

On March 28, 2012, EPA released its proposal for a New Source Performance Standard (NSPS) limiting greenhouse gas emissions from new fossil-fired power plants. The proposal would require new plants to have a greenhouse gas emission rate equal to or lower than that of a new combined-cycle natural gas plant, essentially preventing the construction of new coal-fired power plants without carbon capture and storage technology. EPA has yet to propose standards for existing power plants.

Cross-State Air Pollution Rule

In 2005, EPA issued the Clean Air Interstate Rule (CAIR), building on progress made under the NOx SIP Call to reduce the transport of ozone and fine particulates (PM-2.5) in the eastern U.S. CAIR requires that 28 eastern states and the District of Columbia that contribute to ozone and/or PM-2.5 nonattainment problems in downwind states achieve further reductions in SO_2 and NOx emissions from power plants and/or other sources.

After vacating CAIR earlier in 2008, on December 23, 2008, the D.C. Circuit sent the rule back to the Agency for reconsideration while leaving the program in place until EPA issued a replacement rule. On July 7, 2011, EPA published its final rule replacing CAIR, called the Cross-State Air Pollution Rule (CSAPR). The final rule limits SO_2 and/or NOx emissions from power plants in 28 states. On December 7, 2011, the D.C. Circuit stayed the rule pending litigation from a number of states, utilities, and industry groups. While the rule is stayed, CAIR remains in effect.

Mercury and Other Hazardous Air Pollutants

Section 112 of the Clean Air Act requires EPA to regulate emissions of hazardous air pollutants, including mercury, nickel, arsenic, acid gases, and other toxic pollutants, through the establishment of maximum achievable control technology (MACT) standards. In December 2011, EPA released the first-ever federal limits on hazardous air pollutants from coal-fired power plants, known as the Mercury and Air Toxics Standards (MATS). The rule replaces the 2005 Clean Air Mercury Rule, which was vacated by the D.C. Circuit in 2008, and requires overall reductions in mercury emissions of 90 percent, as well as reductions in acid gases and other toxic metals. The rule is expected to drive investment in new generation as well as installation of emission control retrofits, such as mercury controls, scrubbers, and particulate filters.

TABLE 1

Hazardous Air Pollutants Regulated under the MATS Rule

Hazardous Air Pollutant	Human Health Hazards	Contribution from Power Plants
Mercury	Damage to brain, nervous system, kidneys and liver. Causes neurological and developmental birth defects.	68%
Acid Gases (e.g., hydrogen chloride, hydrogen fluoride)	Irritation to skin, eyes, nose, throat, breathing passages.	77%
Non-Mercury Metals and Metalloids (e.g., antimony, arsenic, beryllium, cadmium, chromium, nickel, selenium, manganese, lead)	Carcinogens: lung, bladder, kidney, skin. May adversely affect nervous, cardiovascular, dermal, respiratory and immune systems.	77%
Dioxins and Furans	Probable Carcinogen: Stomach and immune system. Affects reproductive endocrine and immune system.	unkown

SOURCE: AMERICAN LUNG ASSOCIATION. TOXIC AIR: THE CASE FOR CLEANING UP COAL-FIRED POWER PLANTS. MARCH 2011; U.S. EPA. MERCURY AND AIR TOXICS STANDARDS WEBPAGE. ACCESSED JUNE 7, 2012. MERCURY PERCENTAGE FROM, U.S. EPA, "U.S. EPA TOXICS RELEASE INVENTORY REPORTING YEAR 2010 NATIONAL ANALYSIS: OVERVIEW." P. 7. JANUARY 2012.

Affected facilities are generally required to comply with the standards for hazardous air pollutants by 2015; however, the rule allows for compliance extensions until 2016 on a case-by-case basis. The rule is currently being challenged in the courts. A decision is not expected until next year.

Eighteen states have also adopted mercury emissions standards for coal-fired power plants under independent state law.

Coal Ash Waste and Cooling Water Intake Structures

In addition to the air quality and climate change regulations that are under consideration at the federal level, the EPA is also considering possible changes to waste and water quality regulations that could have major cost implications for the electric industry.

The large coal ash spill at the Tennessee Valley Authority's Kingston Power Plant on December 22, 2008, brought national attention to the challenges associated with the storage and disposal of coal combustion byproducts. The combustion of coal produces a variety of solid waste materials, including fly ash, bottom ash, boiler slag, and other waste byproducts, that require proper treatment and disposal. Some of these materials are reused in cement and concrete products, but most are disposed of in landfills, ash ponds, and abandoned coal mines. On June 21, 2010, EPA proposed two options to regulate coal ash disposal under the Resource Conservation and Recovery Act (which governs solid waste disposal). The options proposed are to regulate coal ash as either hazardous or non-hazardous waste. EPA has not stated when the proposal will be finalized.

Many large power plants, including fossil and nuclear facilities, utilize water from lakes, rivers, and oceans in order to dissipate surplus heat generated in the production of electricity. In a "once-through" cooling system, millions of gallons of water are withdrawn each day, run through the plant, and discharged back to the environment. Section 316(b) of the Clean Water Act requires cooling water intake structures to reflect the "best technology available" for minimizing adverse environmental impacts associated with the intake of cooling water. In April 2011, EPA proposed new regulations governing cooling water intake structures at existing power plants. The final regulation is expected in 2012.

Industry in Transition

Electric utilities and independent power producers are facing strong economic headwinds. Natural gas prices have fallen dramatically, as detailed in the Market Trends section. This, in turn, has led to a decline in wholesale power prices, reducing the revenues earned by power plant operators. In the nation's largest competitive power market—the PJM Interconnection—wholesale power prices declined almost 30 percent in 2011, when compared to their peak in 2008.[30] With the exception of Texas, which experienced record summer temperatures, average wholesale power prices have fallen across the country between 2010 and 2011.[31] In addition to the economic pressures brought by lower natural gas prices, electricity demand has been sluggish due to: (1) economic conditions, (2) increased competition from demand-side resources, and (3) the mild winter weather experienced throughout the country. Low demand for electricity tends to moderate electricity prices and reduces the level at which a power plant might otherwise be called upon to operate.

At the same time, companies are facing new environmental standards, including limits on mercury and other toxic air pollutants. In some cases, plant owners have already invested in the pollution control systems needed to comply with these standards. However, many coal-fired generating units operate without more advanced pollution control equipment, particularly older and smaller units. Some of these generating facilities are opting to retire because they are unable to justify further investment in light of the current and projected market conditions. As described above, since January 2010, plant owners have announced about 40 GW of coal plant retirements or roughly 12 percent of the nation's coal-fired generating fleet.[32]

Power market rules are also driving changes in the electric industry. The Federal Energy Regulatory Commission (FERC)—the agency that oversees the U.S. electric industry—has been encouraging the increased use of "demand-side resources" in lieu of building new electric generating and transmission facilities. FERC Order 745, issued in March 2011, directs the organized power markets to institute incentive payments for "demand response" resources—electricity customers that are willing to curtail their electricity consumption when requested by the system operator. FERC's order is currently being challenged in the courts and debate is ongoing in terms of the use of backup generators in demand response programs.

Fuel price dynamics, changing market conditions, new environmental standards, and new market rules are forcing difficult decisions in the board rooms of power companies and the hearing rooms of state public utility commissions, particularly among owners of older generating facilities that have long avoided modern upgrades to their fleet.

Table 2 highlights some of the changes that are planned among the nation's largest electric generating companies. Many companies are transitioning to cleaner energy resources over the next decade through a combination of retirements, new plant construction, and pollution control retrofits.

The South Point Energy Center, a 520 MW natural gas combined cycle power plant in Arizona.
PHOTO CREDIT: CALPINE CORPORATION

TABLE 2

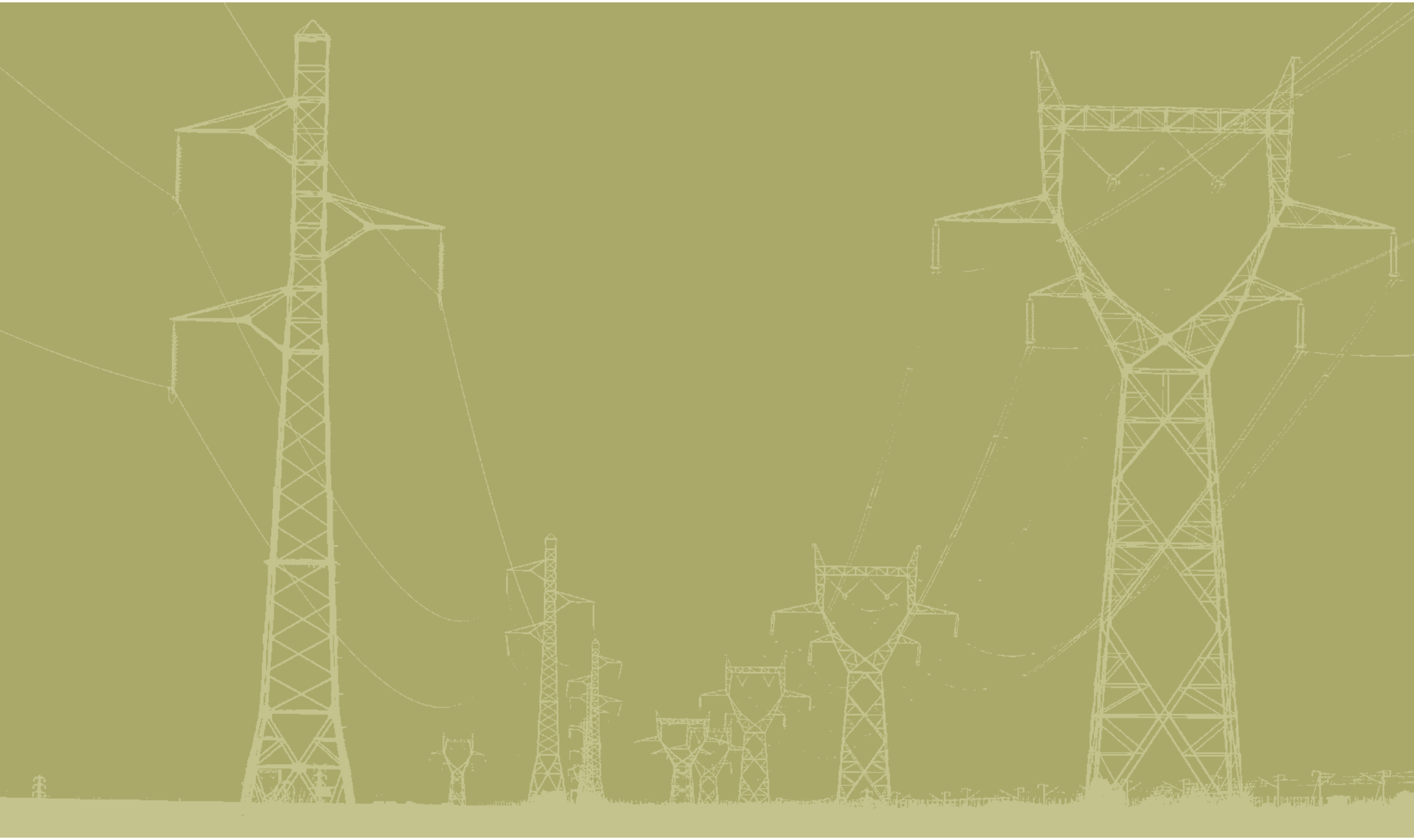
Planned Changes to the Generating Fleets of the Nation's Largest Electric Generating Companies

Rank based on 2010 generation	**Company**	**Summary of Expected Fleet Changes**
1	Southern	In 2006, Southern Company produced 67% of its power from coal. In 2011, the company's coal generation had fallen to 52% of the company's total power generation, with natural gas increasing to 30%. Looking forward, Southern Company is pursuing the development of two new nuclear generating units at its Plant Vogtle site in Georgia. The company expects Unit 3 to begin operating in 2016 and Unit 4 in 2017, making the units the first new nuclear units built in the U.S. in the last three decades.
2	AEP	AEP is planning to retire several older, less efficient power plants (~2,600 MW) from its regulated fleet. The retired capacity will be replaced in part by the Dresden Combined Cycle facility (580 MW) and the Turk Coal Plant (440 MW). AEP is also planning to retire 2,538 MW from its competitive generating fleet. AEP's competitive fleet in 2015 will consistent primarily of controlled coal and natural gas-fired facilities.
3	TVA	In August 2010, the TVA board of directors adopted a new vision for TVA to be one of nation's leading providers of low-cost and cleaner energy by 2020. To achieve that vision, TVA will focus on increased nuclear generation, reduced air emissions, and greater reliance on energy efficiency. As part of its plan, TVA approved plans to add pollution control systems at the Gallatin and Allen coal plants; the John Sevier Combined Cycle Plant (880 MW) started commercial operation in April 2012; and TVA is working to finish a partially completed nuclear generating unit (Watts Bar 2; construction was suspended in 1985).
4	NextEra	In 2011, NextEra Energy produced 58% of its power from natural gas, 23% from nuclear, and 14% from wind. NextEra Energy has been phasing out older, oil-fired units in Florida, replacing them with natural gas-fired generating capacity. The Cape Canaveral Next Generation Clean Energy Center (1,250 MW) is scheduled to open in 2013 and the Riviera Beach Next Generation Clean Energy Center (1,250 MW) is scheduled to open in 2014. NextEra Energy is the largest wind and solar energy generator in the U.S. and aims to add 1,300 MW of new wind assets to its portfolio in 2012. The company also expects to bring roughly 900 MW of new solar projects into service from 2012 through 2016.
5	Exelon	Exelon Corporation completed its merger with Constellation Energy on March 12, 2012. After planned divestitures, Exelon will have more than 19,000 MW of nuclear generating capacity and 15,500 MW of natural gas, hydroelectric, oil, coal, wind, and solar generating capacity.
6	Duke	Duke Energy is in the midst of a "fleet modernization" initiative, which will add two new coal (1,440 MW) and two new natural gas plants (1,240 MW) to the company's fleet, including an integrated gasification combined-cycle (IGCC) coal plant. The company may also retire 3,800 megawatts of older coal plants by 2015. Duke is also exploring potential nuclear uprate projects. In July 2012, Duke Energy completed its merger with Progress Energy.
7	Entergy	Entergy is the second-largest nuclear generator in the U.S. After receiving regulatory approval in 2012, Entergy Louisiana began constructing a 550 MW combined-cycle facility at its existing Ninemile Point Plant. In 2011, Entergy Arkansas and Entergy Mississippi each announced plans to purchase a natural gas combined-cycle facility. Entergy's competitive power business purchased the Rhode Island State Energy Center in 2011, a 583 MW natural gas combined-cycle facility.
8	Dominion	In 2011, Dominion completed a new 590 MW natural gas-fired power plant, and plans to construct another three large natural-gas fired plants over the next decade. Dominion Virginia also plans to retire two coal units, convert three to burn biomass, and convert several others from coal to natural gas. Dominion will also shut down its Salem Harbor and State Line plants in Massachusetts and Illinois, respectively. In 2011, Dominion began operation of a new scrubber at the Chesterfield Power Station in Virginia.
9	MidAmerican	MidAmerican plans to construct two combined-cycle natural gas plants by 2016 as well as 407 MW of wind generation by 2012 (in addition to the 2,909 MW the company already owns). It also anticipates spending $1.4 billion on emissions controls between 2012 and 2014, and is evaluating potential retirements of coal-fired units.
10	Progress Energy	In 2011, Progress Energy's generation fuel mix was 35% coal, 33% gas and oil, and 31% nuclear. Progress Energy is planning to retire several coal plants, including Lee (397 MW), Sutton (600 MW), Weatherspoon (172 MW), and Cape Fear (316 MW). Progress Energy is replacing the Lee plant with a 950 MW natural gas combined cycle facility and the Sutton plant with a 620 MW natural gas combined cycle facility. In July 2012, Duke Energy completed its merger with Progress Energy.
11	Calpine	Calpine operates a large fleet of natural-fired power plants with an average age of about 12 years. In 2011, Calpine produced 94% of its power from natural gas and 6% from geothermal facilities in California. Calpine has two natural gas combined cycle facilities under construction in California (584 MW).
12	Edison	In early 2012, California and Arizona regulators approved a deal for Southern California Edison (SCE) to sell its 48% share in the coal-fired Four Corners power plant to APS, leaving SCE with no coal plants in their generating portfolio. Edison Mission Group, Edison International's other subsidiary, has recently announced they are transferring their interest in the Homer City coal-fired plant to its other owners and retiring their two Chicago-based coal plants over the next two years.
13	FirstEnergy	FirstEnergy completed its merger with Allegheny Energy in February 2011. Over the next several years, FirstEnergy is planning to retire 3,350 MW of coal-fired generating capacity. According to the company's Annual Report: "their use was limited by relatively high operating costs compared with other units in our fleet…[u]pon retirement of these units, nearly 100 percent of the power we generate will come from low- or non-emitting sources, including nuclear, natural gas, scrubbed coal and renewable energy." FirstEnergy is also planning $1.3 billion to $1.7 billion in environmental retrofits.
14	Ameren	Ameren announced in 2011 it would close its Meredosia and Hutsonville coal-fired plants in Illinois. The company's Missouri subsidiary's 2011 IRP explores several options for the company's future generation mix, all of which include an increased share of natural gas (which currently makes up only 1% of Ameren Missouri's portfolio) and a decreased share of coal.
15	Xcel	Xcel's Clean Air-Clean Jobs plan in Colorado calls for the shutdown of 593 MW of coal-fired generation and their replacement with a 569 MW natural gas plant; the switching of two units from burning coal to burning natural gas; and installation of emissions controls on 951 MW of coal-fired generation, all over the next five years.

SOURCE: SEE ENDNOTE 35

These changes to the electric generating fleet are expected to produce significant reductions in NOx, SO_2, and mercury emissions. For example, modeling by the EIA forecasts a 40 percent reduction in SO_2 emissions, a 30 percent reduction in NOx emissions, and an 85 percent reduction in mercury emissions between 2010 and 2015—assuming implementation of EPA's clean air rules and continued low natural gas prices.[33]

By contrast, the on-going changes to the fleet are not expected to have a significant effect on future CO_2 emissions. After declining through the middle of the decade, in response to factors like coal plant retirements and increased natural gas use, EIA projects that electric sector CO_2 emissions will return to 2010 levels by 2020—assuming that no policies are put in place to control greenhouse gas emissions from existing fossil fuel-fired power plants. EIA's modeling finds that coal-fired generation increases in 2020, as plants that "overcome the regulatory hurdle" and install pollution control equipment are run more frequently.[34]



Emissions of the 100 Largest Electric Power Producers

In 2010, the 100 largest power producers in the U.S. generated 86 percent of the nation's electricity supply and 88 percent of the industry's air pollution emissions. Table 1 lists the 100 largest electric power producers in order of their total 2010 electric generation in MWh. The three largest producers were responsible for 15 percent of the 3.5 billion MWh of electricity generated by the 100 largest producers. The 100 largest power producers emitted approximately 4.7 million tons of SO_2, 1.8 million tons of NOx, 30 tons of mercury, and 2.2 billion tons of CO_2. The top three producers were responsible for 20 percent of the SO_2, 15 percent of the NOx, 15 percent of the mercury, and 16 percent of the CO_2 emissions of the 100 largest producers.

The average and median emission levels (tons) and emission rates (lbs/MWh) shown in Table 1 provide benchmark measures of overall industry emissions that can be used as reference points to evaluate the emissions performance of individual power producers.

TABLE 3

Emissions Data for 100 Largest Power Producers
in order of 2010 generation

			2010 Generation (MWh)			2010 Emissions (tons)				Emission Rates (lbs/MWh)									
										All Generating Sources			Fossil Fuel Plants †			Coal Plants ††			
Rank	**Owner**	**Ownership Type**	**Total**	**Fossil Fuel**	**Coal**	**SO_2**	**NOx**	**CO_2**	**Hg***	**SO_2**	**NOx**	**CO_2**	**SO_2**	**NOx**	**CO_2**	**SO_2**	**NOx**	**CO_2**	**Hg†††**
1	Southern	investor-owned corp.	197,975,260	163,641,595	113,595,443	392,049	113,216	144,822,053	2.06	4.0	1.1	1,463	4.8	1.4	1,770	6.9	1.9	2,163	0.04
2	AEP	investor-owned corp.	174,093,447	156,734,901	142,288,545	498,009	129,951	154,858,540	3.06	5.7	1.5	1,779	6.4	1.7	1,976	7.0	1.6	2,056	0.04
3	NextEra Energy	investor-owned corp.	165,672,221	100,478,445	6,241,523	36,944	25,921	50,743,519	0.03	0.4	0.3	613	0.7	0.5	1,010	4.9	1.5	2,179	0.01
4	Duke	investor-owned corp.	156,115,602	107,098,636	93,574,343	238,181	75,193	100,165,488	0.69	3.1	1.0	1,283	4.4	1.4	1,870	5.1	1.6	2,005	0.01
5	Exelon	investor-owned corp.	152,698,385	9,130,317	7,386,982	16,911	10,697	9,520,088	0.11	0.2	0.1	125	3.7	2.3	2,085	4.5	2.7	2,241	0.03
6	Tennessee Valley Authority	federal power authority	143,854,084	79,135,692	75,976,301	220,238	71,591	84,090,517	0.92	3.1	1.0	1,169	5.6	1.8	2,125	5.8	1.9	2,173	0.02
7	Entergy	investor-owned corp.	126,532,342	44,243,747	16,029,227	46,123	47,005	35,515,694	0.43	0.7	0.7	561	2.1	2.1	1,605	5.6	2.5	2,175	0.05
8	Dominion	investor-owned corp.	110,223,068	62,207,843	44,559,614	143,290	58,205	56,018,259	0.53	2.6	1.1	1,016	4.6	1.9	1,801	6.3	2.4	2,136	0.02
9	Progress Energy	investor-owned corp.	94,901,844	72,670,041	42,568,640	127,600	43,175	60,338,675	0.49	2.7	0.9	1,272	3.5	1.2	1,661	5.6	1.7	2,127	0.02
10	MidAmerican	privately held corp.	91,537,297	76,355,734	66,617,400	119,078	93,780	78,769,235	1.02	2.6	2.0	1,721	3.1	2.5	2,063	3.6	2.8	2,237	0.03
11	PPL	investor-owned corp.	91,035,830	69,473,321	64,463,560	161,641	69,042	70,351,286	0.91	3.6	1.5	1,546	4.7	2.0	2,025	5.0	2.1	2,096	0.03
12	Calpine	investor-owned corp.	89,666,690	83,119,556	-	237	6,307	36,134,130	-	0.0	0.1	806	0.0	0.2	863	-	-	-	-
13	Edison International	investor-owned corp.	82,735,676	58,871,275	45,735,647	193,223	53,175	56,059,669	0.60	4.7	1.3	1,355	6.6	1.8	1,899	8.4	2.3	2,227	0.03
14	Ameren	investor-owned corp.	76,537,705	65,394,136	64,462,704	215,673	41,254	71,387,737	1.90	5.6	1.1	1,865	6.6	1.3	2,183	6.7	1.3	2,198	0.06
15	Xcel	investor-owned corp.	76,180,783	60,882,827	46,205,184	95,565	62,494	60,180,349	0.78	2.5	1.6	1,580	3.1	2.0	1,977	4.1	2.5	2,263	0.03
16	FirstEnergy	investor-owned corp.	75,278,215	44,479,848	43,210,420	130,269	43,143	47,215,028	0.58	3.5	1.1	1,254	5.9	1.9	2,123	5.9	1.9	2,122	0.03
17	NRG	investor-owned corp.	74,402,363	63,773,649	48,506,424	132,985	39,817	62,694,387	1.47	3.6	1.1	1,685	4.2	1.2	1,962	5.4	1.5	2,239	0.06
18	Energy Future Holdings	privately held corp.	73,201,654	52,993,187	50,571,758	215,942	41,019	63,934,954	3.20	5.9	1.1	1,747	8.1	1.5	2,413	8.5	1.5	2,464	0.13
19	PSEG	investor-owned corp.	65,025,351	35,378,137	10,676,988	23,924	14,525	23,202,407	0.09	0.7	0.4	714	1.4	0.8	1,309	4.1	1.8	2,171	0.02
20	US Corps of Engineers	federal power authority	64,437,340	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	DTE Energy	investor-owned corp.	48,784,339	40,458,564	39,542,241	142,716	44,067	43,251,831	0.76	5.9	1.8	1,773	7.1	2.2	2,138	7.2	2.2	2,156	0.04
22	AES	investor-owned corp.	44,443,039	41,810,825	30,695,902	98,757	28,651	39,556,486	0.52	4.4	1.3	1,780	4.7	1.4	1,892	6.3	1.8	2,175	0.03
23	US Bureau of Reclamation	federal power authority	41,249,946	3,992,391	3,984,675	1,239	5,936	4,325,007	0.07	0.1	0.3	210	0.6	3.0	2,167	0.6	3.0	2,171	0.03
24	GenOn	investor-owned corp.	41,225,906	41,225,906	33,393,344	168,804	41,226	39,643,010	0.75	8.2	2.0	1,923	8.2	2.0	1,923	10.1	2.4	2,106	0.04
25	Allegheny Energy	investor-owned corp.	41,016,149	40,828,799	39,717,075	66,474	57,496	42,314,163	0.71	3.2	2.8	2,063	3.3	2.8	2,073	3.3	2.9	2,105	0.04
26	Dynegy	investor-owned corp.	38,585,118	38,585,118	23,943,363	56,166	12,811	32,435,730	0.16	2.9	0.7	1,681	2.9	0.7	1,681	4.7	1.0	2,167	0.01
27	Constellation	investor-owned corp.	35,215,166	18,468,329	13,845,960	26,034	11,898	17,177,582	0.08	1.5	0.7	976	2.8	1.3	1,859	3.7	1.6	2,135	0.01
28	PG&E	investor-owned corp.	32,473,598	3,641,357	-	42	889	1,816,152	-	0.0	0.1	112	0.0	0.5	998	-	-	-	-
29	Westar	investor-owned corp.	28,397,238	23,453,004	21,443,866	18,960	29,346	26,349,988	0.45	1.3	2.1	1,856	1.6	2.5	2,247	1.8	2.6	2,339	0.04
30	Santee Cooper	state power authority	27,886,857	24,709,243	21,705,762	30,084	12,702	24,565,016	0.10	2.2	0.9	1,762	2.4	1.0	1,986	2.8	1.1	2,132	0.01
31	Pinnacle West	investor-owned corp.	26,848,283	17,762,844	12,168,425	9,114	24,516	15,767,362	0.22	0.7	1.8	1,175	1.0	2.8	1,775	1.5	3.9	2,184	0.04
32	Great Plains Energy	investor-owned corp.	26,326,738	21,441,261	20,873,403	38,848	20,125	24,411,581	0.33	3.0	1.5	1,855	3.6	1.9	2,277	3.7	1.9	2,305	0.03
33	SCANA	investor-owned corp.	26,050,460	19,831,068	13,572,873	48,482	10,786	16,588,082	0.12	3.7	0.8	1,274	4.9	1.1	1,673	7.1	1.5	2,045	0.02
34	Salt River Project	power district	25,835,413	19,958,947	16,455,167	16,756	27,548	20,136,334	0.36	1.3	2.1	1,559	1.7	2.8	2,018	2.0	3.3	2,255	0.04
35	OGE	investor-owned corp.	25,184,002	24,479,047	14,098,645	41,165	30,838	21,485,333	0.21	3.3	2.4	1,706	3.4	2.5	1,755	5.8	3.5	2,189	0.03
36	New York Power Authority	state power authority	24,775,602	4,395,321	-	16	211	2,111,355	-	0.0	0.0	170	0.0	0.1	961	-	-	-	-
37	San Antonio City	municipality	22,525,164	14,074,452	12,143,775	22,507	9,133	15,743,546	0.27	2.0	0.8	1,398	3.2	1.3	2,237	3.7	1.3	2,321	0.04
38	CMS Energy	investor-owned corp.	22,185,926	20,988,407	17,895,923	74,042	20,636	21,141,887	0.23	6.7	1.9	1,906	7.0	1.9	1,976	8.2	2.1	2,179	0.03
39	Oglethorpe	cooperative	21,983,607	11,929,997	9,630,623	21,669	6,164	11,584,918	0.05	2.0	0.6	1,054	3.6	1.0	1,942	4.5	1.2	2,154	0.01
40	NV Energy	investor-owned corp.	20,526,715	20,526,715	5,157,891	4,616	9,214	12,483,079	0.08	0.4	0.9	1,216	0.4	0.9	1,216	1.8	3.1	2,278	0.03
41	Wisconsin Energy	investor-owned corp.	20,484,492	19,853,208	17,029,643	28,472	14,874	23,127,460	0.18	2.8	1.5	2,258	2.9	1.5	2,330	3.3	1.7	2,563	0.02
42	TECO	investor-owned corp.	19,049,262	19,049,262	10,561,350	9,639	5,340	16,513,642	0.05	1.0	0.6	1,734	1.0	0.6	1,734	1.8	0.9	2,400	0.01
43	Rockland Capital	privately held corp.	18,577,790	18,577,790	573,436	1,978	2,187	7,746,953	0.00	0.2	0.2	834	0.2	0.2	834	6.5	4.6	2,282	0.02
44	Associated Electric Coop	cooperative	18,027,712	18,027,712	14,895,437	32,115	11,583	17,382,138	0.22	3.6	1.3	1,928	3.6	1.3	1,928	4.3	1.5	2,139	0.03
45	EDF	foreign-owned corp.	17,885,102	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
46	Alliant Energy	investor-owned corp.	17,738,549	16,897,653	15,920,868	71,821	19,942	19,420,118	0.46	8.1	2.2	2,190	8.5	2.4	2,298	9.0	2.5	2,348	0.06
47	NE Public Power District	power district	17,510,123	10,425,817	10,311,788	33,501	19,022	11,883,373	0.14	3.8	2.2	1,357	6.4	3.6	2,280	6.5	3.7	2,294	0.03
48	Sempra	investor-owned corp.	17,015,869	13,960,937	-	30	449	6,045,003	-	0.0	0.1	711	0.0	0.1	866	-	-	-	-
49	General Electric	investor-owned corp.	16,841,948	16,367,258	20,363	62	1,802	7,193,160	0.00	0.0	0.2	854	0.0	0.2	876	1.1	0.9	2,141	0.00
50	Basin Electric Power Coop	cooperative	15,992,224	15,601,788	15,509,872	64,826	26,442	18,597,404	0.42	8.1	3.3	2,326	8.3	3.4	2,384	8.4	3.4	2,394	0.05
51	Omaha Public Power District	power district	15,870,079	11,555,128	11,405,698	24,811	15,638	12,646,302	0.35	3.1	2.0	1,594	4.3	2.7	2,189	4.4	2.7	2,204	0.06
52	DPL	investor-owned corp.	15,734,400	15,734,400	15,513,247	36,996	13,065	16,234,026	0.10	4.7	1.7	2,064	4.7	1.7	2,064	4.8	1.7	2,074	0.01

* Mercury emissions are based on 2010 TRI data for coal plants
† Fossil fuel emission rate = pounds of pollution per MWh of electricity produced from fossil fuel
†† Coal emission rate = pounds of pollution per MWh of electricity produced from coal
††† Mercury emissions rate = pounds of mercury per gigawatt hour (GWh) of electricity produced from coal

			2010 Generation (MWh)			2010 Emissions (tons)				Emission Rates (lbs/MWh)									
										All Generating Sources			Fossil Fuel Plants †			Coal Plants ††			
Rank	Owner	Ownership Type	Total	Fossil Fuel	Coal	SO_2	NOx	CO_2	Hg*	SO_2	NOx	CO_2	SO_2	NOx	CO_2	SO_2	NOx	CO_2	Hg†††
53	International Power	foreign-owned corp.	15,719,213	15,682,827	4,471,852	17,640	3,760	9,777,124	0.11	2.2	0.5	1,244	2.2	0.5	1,244	7.9	1.4	2,040	0.05
54	NiSource	investor-owned corp.	15,534,598	15,484,704	13,847,819	45,960	13,620	17,618,962	0.34	5.9	1.8	2,268	5.9	1.8	2,276	6.6	1.9	2,444	0.05
55	US Power Generating Company	privately held corp.	15,511,947	15,511,947	-	253	1,793	7,217,582	-	0.0	0.2	931	0.0	0.2	931	-	-	-	-
56	JEA	municipality	15,433,685	15,430,793	9,036,871	15,786	8,883	15,013,729	0.05	2.0	1.2	1,946	2.0	1.2	1,946	2.7	1.4	2,177	0.01
57	SUEZ Energy	foreign-owned corp.	15,027,994	13,919,073	1,088,595	1,464	2,729	6,367,537	0.01	0.2	0.4	847	0.2	0.4	915	2.6	1.7	2,294	0.01
58	IDACORP	investor-owned corp.	14,363,485	6,946,895	6,776,915	9,272	9,120	7,471,783	0.12	1.3	1.3	1,040	2.7	2.6	2,151	2.7	2.7	2,176	0.03
59	Occidental	investor-owned corp.	14,059,028	13,977,290	-	10	661	6,430,663	-	0.0	0.1	915	0.0	0.1	913	-	-	-	-
60	Los Angeles City	municipality	13,623,435	10,542,238	3,476,342	1,105	5,385	7,355,446	0.06	0.2	0.8	1,080	0.2	1.0	1,395	0.6	3.0	2,171	0.03
61	PNM Resources	investor-owned corp.	13,438,103	10,255,709	7,187,284	5,744	11,989	9,819,574	0.10	0.9	1.8	1,461	1.1	2.3	1,915	1.6	3.2	2,258	0.03
62	Tri-State	cooperative	13,421,898	13,421,898	13,365,697	8,017	18,142	15,393,380	0.10	1.2	2.7	2,294	1.2	2.7	2,294	1.2	2.7	2,290	0.01
63	Tenaska	privately held corp.	13,086,568	13,020,058	-	30	876	5,761,265	-	0.0	0.1	880	0.0	0.1	885	-	-	-	-
64	Intermountain Power Agency	power district	13,079,502	13,079,502	13,069,438	5,000	26,152	13,080,935	0.10	0.8	4.0	2,000	0.8	4.0	2,000	0.8	4.0	2,002	0.02
65	Municipal Elec. Auth. of GA	municipality	12,817,929	5,905,775	4,847,414	10,906	3,017	5,679,849	0.02	1.7	0.5	886	3.7	1.0	1,923	4.5	1.2	2,154	0.01
66	Dow Chemical	investor-owned corp.	12,664,586	12,007,931	-	13	419	5,379,890	-	0.0	0.1	850	0.0	0.1	837	-	-	-	-
67	Energy Capital Partners	privately held corp.	12,479,671	12,479,671	-	28	443	5,394,832	-	0.0	0.1	865	0.0	0.1	865	-	-	-	-
68	NC Public Power	municipality	12,371,316	1,400,455	1,387,825	1,324	573	1,460,040	0.01	0.2	0.1	236	1.9	0.8	2,085	1.9	0.8	2,087	0.01
69	East Kentucky Power Coop	cooperative	12,283,755	12,194,607	11,758,035	31,980	9,699	13,075,405	0.12	5.2	1.6	2,129	5.2	1.6	2,144	5.4	1.6	2,167	0.02
70	Lower CO River Authority	state power authority	11,946,974	11,765,633	7,034,112	17,133	5,014	10,324,842	0.11	2.9	0.8	1,728	2.9	0.9	1,755	4.9	1.2	2,234	0.03
71	Seminole Electric Coop	cooperative	11,749,493	11,749,491	8,898,763	16,972	2,844	10,723,098	0.05	2.9	0.5	1,825	2.9	0.5	1,825	3.8	0.5	2,105	0.01
72	Exxon Mobil	investor-owned corp.	11,600,728	10,706,069	-	11	415	4,235,129	-	0.0	0.1	730	0.0	0.1	727	-	-	-	-
73	Portland General Electric	investor-owned corp.	11,506,509	9,363,672	4,901,287	12,387	8,682	7,273,995	0.08	2.2	1.5	1,264	2.6	1.9	1,554	5.0	3.4	2,192	0.03
74	Arkansas Electric Coop	cooperative	11,421,821	10,698,225	9,785,912	24,355	13,649	10,926,950	0.24	4.3	2.4	1,913	4.6	2.6	2,043	5.0	2.7	2,133	0.05
75	Integrys	investor-owned corp.	11,325,461	10,557,392	10,416,048	25,880	8,213	11,815,154	0.22	4.6	1.5	2,086	4.9	1.5	2,221	4.9	1.6	2,236	0.04
76	Puget Holdings	privately held corp.	11,168,761	9,239,667	5,326,706	5,282	6,392	7,938,748	0.02	0.9	1.1	1,422	1.1	1.4	1,718	2.0	2.3	2,313	0.01
77	Iberdrola	foreign-owned corp.	11,078,069	1,012,214	-	2	54	411,648	-	0.0	0.0	74	0.0	0.1	813	-	-	-	-
78	TransAlta	foreign-owned corp.	10,442,647	9,087,203	8,486,571	2,616	11,668	10,943,991	0.17	0.5	2.2	2,096	0.6	2.6	2,409	0.6	2.7	2,508	0.04
79	Great River Energy	cooperative	10,389,302	10,318,389	10,046,554	20,565	10,709	11,793,077	0.42	4.0	2.1	2,270	4.0	2.1	2,286	4.1	2.1	2,305	0.08
80	Austin Energy	municipality	10,372,953	6,992,668	4,024,167	9,810	3,262	6,102,200	0.07	1.9	0.6	1,177	2.8	0.9	1,745	4.9	1.2	2,234	0.03
81	UniSource	investor-owned corp.	9,803,050	9,797,180	8,586,353	6,105	11,062	10,277,860	0.09	1.2	2.3	2,097	1.2	2.3	2,098	1.4	2.5	2,267	0.02
82	Big Rivers Electric	cooperative	9,748,681	9,748,681	7,630,297	21,900	11,196	11,506,109	0.10	4.5	2.3	2,361	4.5	2.3	2,361	5.7	2.9	2,341	0.03
83	ALLETE	investor-owned corp.	9,722,195	8,893,561	8,878,488	19,717	12,761	10,814,771	0.22	4.1	2.6	2,225	4.3	2.7	2,432	4.3	2.7	2,434	0.05
84	BP	foreign-owned corp.	9,570,182	6,738,636	-	100	455	2,635,792	-	0.0	0.1	551	0.0	0.1	703	-	-	-	-
85	Buckeye Power	cooperative	9,458,753	9,458,753	9,377,687	54,029	3,925	9,516,987	0.20	11.4	0.8	2,012	11.4	0.8	2,012	11.5	0.8	2,022	0.04
86	Energy Northwest	municipality	9,357,564	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
87	CLECO	investor-owned corp.	9,344,937	9,344,937	3,308,150	29,125	6,347	8,338,538	0.08	6.2	1.4	1,785	6.2	1.4	1,785	8.0	1.9	2,333	0.05
88	El Paso Electric	investor-owned corp.	8,521,949	3,591,561	699,332	567	4,656	2,608,968	0.01	0.1	1.1	612	0.3	2.6	1,453	1.6	5.6	2,078	0.03
89	Hoosier Energy	cooperative	8,504,209	8,487,283	8,087,136	33,249	5,930	8,711,275	0.09	7.8	1.4	2,049	7.8	1.4	2,053	8.2	1.5	2,106	0.02
90	ArcLight Capital	privately held corp.	8,353,882	8,222,732	-	15	381	3,690,297	-	0.0	0.1	883	0.0	0.1	898	-	-	-	-
91	PUD No 2 of Grant County	power district	8,221,855	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
92	Grand River Dam Authority	state power authority	7,785,928	6,981,697	5,029,411	13,488	11,083	7,212,342	0.27	3.5	2.8	1,853	3.9	3.2	2,066	5.4	4.4	2,517	0.11
93	LS Power	privately held corp.	7,729,992	7,729,992	920,557	760	874	4,237,488	0.05	0.2	0.2	1,096	0.2	0.2	1,096	1.6	0.9	2,649	0.11
94	Chevron	investor-owned corp.	7,661,301	7,435,347	-	5	70	2,510,624	-	0.0	0.0	655	0.0	0.0	666	-	-	-	-
95	PUD No 1 of Chelan County	power district	7,654,238	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
96	International Paper	investor-owned corp.	7,453,728	1,464,201	-	-	495	1,068,889	-	-	0.1	287	-	0.7	1,457	-	-	-	-
97	Sacramento Municipal Util Dist	municipality	7,290,595	5,130,104	-	11	126	2,269,854	-	0.0	0.0	623	0.0	0.0	885	-	-	-	-
98	Avista	investor-owned corp.	7,158,278	3,352,835	1,664,328	1,641	1,952	2,617,975	0.01	0.5	0.5	731	1.0	1.2	1,562	2.0	2.3	2,313	0.01
99	PowerSouth Energy Coop	cooperative	7,008,925	6,987,394	4,004,502	7,721	6,703	6,129,360	0.04	2.2	1.9	1,749	2.2	1.9	1,754	3.9	3.2	2,381	0.02
100	TransCanada	foreign-owned corp.	6,905,947	5,154,112	-	264	1,306	2,937,109	-	0.1	0.4	851	0.1	0.5	1,140	-	-	-	-
		Total (in thousands)	3,539,528	2,455,946	1,662,102	4,677	1,842	2,197,551	0.03										
		Average (mean)	35,395,276	24,559,464	16,621,018	46,769	18,415	21,975,511	0.30	2.5	1.1	1,366	3.0	1.4	1,721	4.6	2.2	2,224	0.03
		Median	15,931,151	13,250,700	8,888,625	17,053	10,198	11,545,514	0.10	2.1	1.1	1,398	2.8	1.4	1,899	4.6	2.0	2,186	0.03

Generation by Fuel Type

The 100 largest power producers in the U.S. accounted for 86 percent of the electricity produced in 2010. Coal accounted for 45 percent of the power produced by the 100 largest companies, followed by natural gas (24 percent), nuclear (20 percent), hydroelectric power (6 percent), oil (1 percent), and non-hydroelectric renewables and other fuel sources (3 and 2 percent, respectively). Natural gas was the source of 37 percent of the power produced by smaller companies, followed by coal (31 percent), non-hydroelectric renewables/other (19 percent), hydroelectric power (8 percent), nuclear power (4 percent), and oil (2 percent).

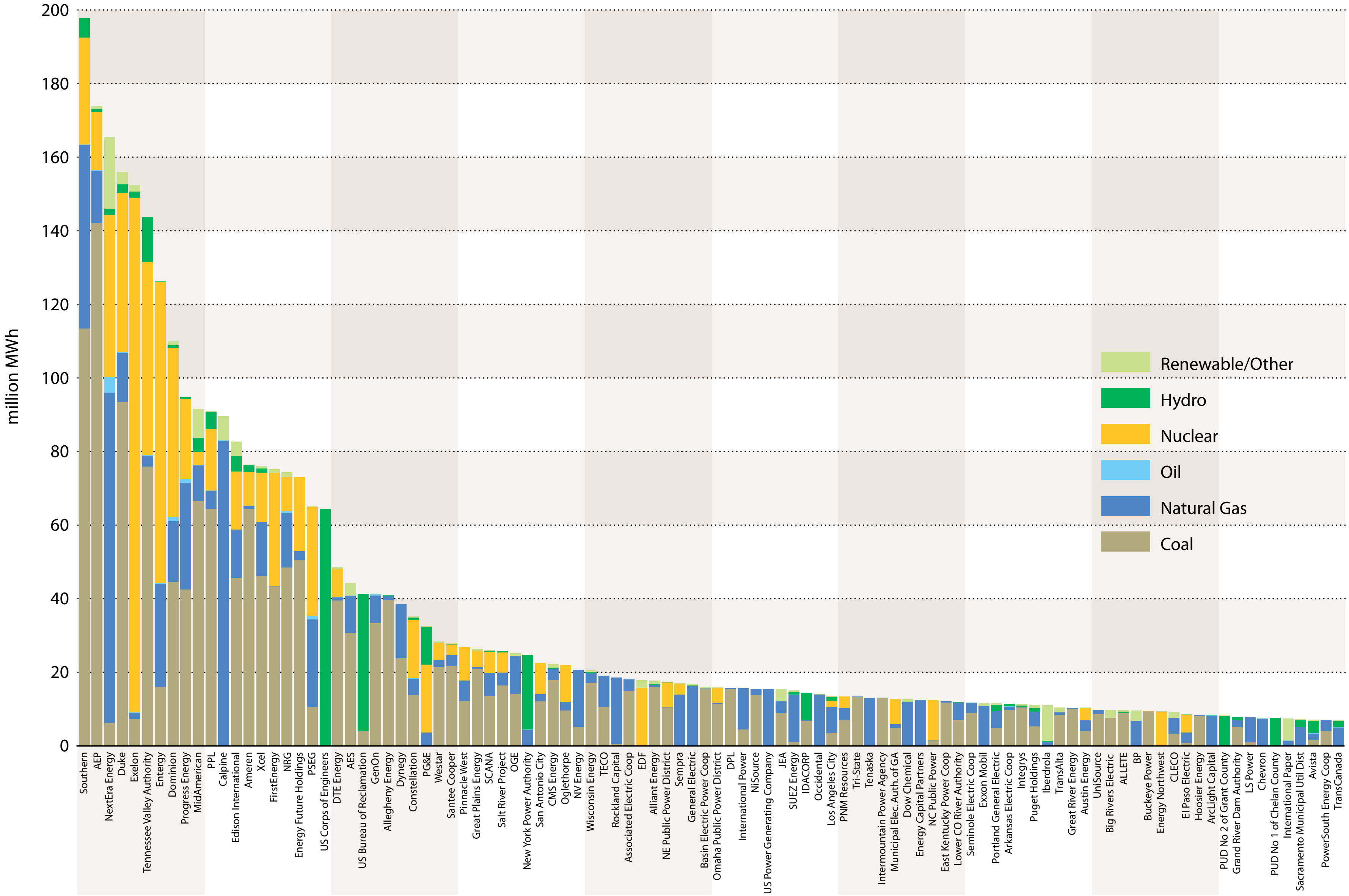
As a portion of total electric power production, the 100 largest companies accounted for 90 percent of all coal-fired power, 78 percent of natural gas-fired power, 54 percent of oil-fired power, 97 percent of nuclear power, 82 percent of hydroelectric power and 62 percent of non-hydroelectric renewable power.

Figure 10 illustrates 2010 electric generation by fuel for each of the 100 largest power producers. The generation levels, expressed in million MWh, show production from facilities wholly and partially owned by each producer and reported to the EIA. Coal or nuclear accounted for over half of the output of the largest generators. The exceptions are a handful of generating companies whose assets are dominated by hydroelectric or natural gas-fired plants. Figure 10 illustrates the modest contribution non-hydroelectric renewable sources made to the total generation of the largest power producers.

These data reflect the mix of generating facilities that are directly owned by the 100 largest power producers, not the energy purchases that some utility companies rely on to meet their customers' electricity needs. For example, some utility companies have signed long-term supply contracts for the output of renewable energy projects. In this report, the output of these facilities would be attributed to the owner of the project, not the buyer of the output.

FIGURE 10

Generation of 100 Largest Power Producers by Fuel Type



Emissions Rankings

Table 4 shows the relative ranking of the 100 largest power producers by several measures—their contribution to total generation (MWh), total emissions and emission rates (emissions per unit of electricity output). These rankings help to evaluate and compare emissions performance.

Figures 11 through 18 illustrate SO_2, NOx, CO_2, and mercury emissions levels (expressed in tons for SO_2, NOx and CO_2, and pounds for mercury) and emission rates for each of the 100 largest producers. These comparisons illustrate the relative emissions performance of each producer based on the company's ownership stake in power plants with reported emissions information. For SO_2 and NOx, the report presents comparisons of total emissions levels and rates for fossil fuel-fired facilities. For CO_2, the report presents comparisons of total emissions levels and rates for all generating sources (e.g., fossil, nuclear, and renewable). For mercury, the report presents comparisons of total emissions levels and rates for coal-fired generating facilities only.

The mercury emissions shown in this report were obtained from EPA's Toxics Release Inventory (TRI). The TRI contains facility-level information on the use and environmental release of chemicals classified as toxic under the Clean Air Act. Because coal plants are the primary source of mercury emissions within the electric industry, the mercury emissions and emission rates presented in this report reflect the emissions associated with each producer's fleet of coal plants only. Other toxic air pollutant emissions, such as hydrogen chloride and hydrogen fluoride (acid gases), are also reported to EPA under the TRI program. However, we have not included these air toxics because of uncertainties about the quality of the data submitted to EPA. We will continue to evaluate whether these pollutants might be included in future benchmarking efforts. In general, there is a strong correlation between SO_2 reductions resulting from flue-gas desulfurization unit (FGD) installations and co-benefit reductions in acid gas emissions.

The emissions data for each pollutant are displayed in several formats to assist with a thorough evaluation of emissions performance. The charts present both the total emissions by company as well as their average emission rates. The charts are sorted by either total emissions or average emission rates. The charts of total emissions provide a breakdown of emissions by fuel type.

The evaluation of emissions performance by both emission levels and emission rates provides a more complete picture of relative emissions performance than viewing these measures in isolation. Total emission levels are useful for understanding each producer's contribution to overall emissions loading, while emission rates are useful for assessing how electric power producers compare according to emissions per unit of energy produced when size is eliminated as a performance factor.

The charts illustrate significant differences in the total emission levels and emission rates of the 100 largest power producers. For example, the tons of CO_2 emissions range from zero to over 155 million tons per year. The NOx emission rates range from zero to 4 pounds of emissions per MWh of generation. The total tons of emissions from any producer are influenced by the total amount of generation that a producer owns and by the fuels and technologies used to generate electricity. Although the amount of generation owned is an important factor, some producers that generated similar amounts of electricity had significantly disparate total emission levels. For example in the top quartile, eight producers each generated between 100 and 200 million MWh of electricity in 2010. Among these producers, emissions ranged from 16,911 tons to 498,009 tons of SO_2, 10,697 tons to 129,951 tons of NOx, and 9.5 million tons to 155 million tons of CO_2.

TABLE 4

Company Rankings for 100 Largest Power Producers
in alphabetical order

		By Generation			By Tons of Emissions				By Emission Rates										
									All Generating Sources			Fossil Fuel Plants			Coal Plants				
Owner	**Ownership Type**	**Total**	**Fossil**	**Coal**	**SO_2**	**NOx**	**CO_2**	**Hg**	**SO_2**	**NOx**	**CO_2**	**SO_2**	**NOx**	**CO_2**	**SO_2**	**NOx**	**CO_2**	**Hg**
AEP	investor-owned corp.	2	2	1	1	1	1	2	11	32	30	12	40	39	13	52	73	20
AES	investor-owned corp.	22	18	18	16	21	19	17	18	37	29	21	49	49	19	46	45	31
Allegheny Energy	investor-owned corp.	25	20	15	20	9	17	12	31	4	14	40	6	27	55	17	68	27
ALLETE	investor-owned corp.	83	75	51	47	39	54	32	20	6	7	28	11	1	44	23	7	12
Alliant Energy	investor-owned corp.	46	38	27	19	29	31	19	4	11	8	2	19	7	3	30	11	8
Ameren	investor-owned corp.	14	10	7	6	15	6	4	12	47	23	9	54	17	15	66	37	7
ArcLight Capital	privately held corp.	90	77	-	88	91	84	-	85	86	70	90	88	83	-	-	-	-
Arkansas Electric Coop	cooperative	74	61	46	41	35	53	30	19	8	21	25	15	32	33	25	61	14
Associated Electric Coop	cooperative	44	36	30	33	44	34	33	26	39	19	37	53	44	45	59	58	41
Austin Energy	municipality	80	80	67	58	71	75	62	51	63	58	49	64	60	36	69	33	34
Avista	investor-owned corp.	98	92	72	71	76	87	75	67	66	79	67	57	67	62	34	17	74
Basin Electric Power Coop	cooperative	50	42	29	21	23	32	22	3	2	2	3	3	4	6	9	9	9
Big Rivers Electric	cooperative	82	68	55	44	45	51	50	17	9	1	26	22	5	24	16	12	47
BP	foreign-owned corp.	84	84	-	81	86	86	-	80	83	88	80	89	94	-	-	-	-
Buckeye Power	cooperative	85	69	48	23	69	61	37	1	56	16	1	67	35	1	76	76	19
Calpine	investor-owned corp.	12	5	-	80	61	20	-	82	79	78	84	83	89	-	-	-	-
Chevron	investor-owned corp.	94	79	-	93	94	89	-	92	93	83	94	95	95	-	-	-	-
CLECO	investor-owned corp.	87	71	71	36	60	63	58	7	36	28	13	50	54	9	44	14	11
CMS Energy	investor-owned corp.	38	28	23	18	27	29	31	6	21	22	8	32	40	7	37	41	49
Constellation	investor-owned corp.	27	35	33	38	42	35	57	53	61	66	48	52	51	51	54	60	66
Dominion	investor-owned corp.	8	12	12	10	8	13	16	42	49	65	24	34	53	20	31	59	51
Dow Chemical	investor-owned corp.	66	55	-	89	89	80	-	89	89	75	91	92	90	-	-	-	-
DPL	investor-owned corp.	52	40	28	29	37	38	48	14	26	13	22	39	29	38	50	72	65
DTE Energy	investor-owned corp.	21	21	16	11	12	16	10	10	23	31	7	24	21	11	36	54	24
Duke	investor-owned corp.	4	3	3	3	4	3	13	34	51	51	27	45	50	30	55	77	62
Dynegy	investor-owned corp.	26	22	19	22	38	22	40	36	62	40	45	71	63	39	72	52	64
East Kentucky Power Coop	cooperative	69	54	39	34	51	44	43	13	28	9	17	41	20	28	53	51	57
EDF	foreign-owned corp.	45	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Edison International	investor-owned corp.	13	14	11	7	10	12	14	15	38	50	10	37	48	5	35	35	48
El Paso Electric	investor-owned corp.	88	91	76	77	68	88	73	76	46	86	73	13	70	70	1	71	33
Energy Capital Partners	privately held corp.	67	53	-	86	88	79	-	84	88	72	87	90	88	-	-	-	-
Energy Future Holdings	privately held corp.	18	15	8	5	17	8	1	9	45	34	5	42	2	4	58	5	1
Energy Northwest	municipality	86	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Entergy	investor-owned corp.	7	17	26	25	11	21	21	64	60	87	55	25	66	25	27	46	10
Exelon	investor-owned corp.	5	73	56	52	50	60	46	70	80	93	34	21	25	42	22	29	42
Exxon Mobil	investor-owned corp.	72	60	-	91	90	83	-	90	87	80	92	91	93	-	-	-	-
FirstEnergy	investor-owned corp.	16	16	13	13	14	15	15	29	42	55	15	30	23	21	41	64	46
General Electric	investor-owned corp.	49	39	78	82	77	71	78	81	78	73	82	82	86	74	73	57	78
GenOn	investor-owned corp.	24	19	17	8	16	18	11	2	18	20	4	28	46	2	32	65	16
Grand River Dam Authority	state power authority	92	82	63	55	46	70	29	28	3	26	32	4	28	29	3	3	2
Great Plains Energy	investor-owned corp.	32	27	22	28	28	25	27	35	29	25	36	33	11	52	43	19	37
Great River Energy	cooperative	79	65	45	46	49	49	23	22	16	4	31	26	9	48	38	18	4
Hoosier Energy	cooperative	89	76	54	32	64	62	56	5	35	15	6	46	31	8	62	66	55
Iberdrola	foreign-owned corp.	77	95	-	94	95	95	-	94	95	95	89	85	92	-	-	-	-
IDACORP	investor-owned corp.	58	83	59	60	54	66	44	56	40	64	50	12	19	58	24	44	28
Integrys	investor-owned corp.	75	62	43	39	57	48	35	16	34	12	19	43	15	34	56	32	22
Intermountain Power Agency	power district	64	51	36	67	24	43	49	62	1	17	68	1	36	75	4	78	61
International Paper	investor-owned corp.	96	93	-	-	85	94	-	-	82	89	-	70	69	-	-	-	-
International Power	foreign-owned corp.	53	41	66	49	70	59	47	44	68	56	53	77	73	10	63	75	15
JEA	municipality	56	45	49	54	55	42	66	48	41	18	56	58	42	59	64	43	69

A ranking of 1 indicates the highest absolute number or rate in any column: the highest generation (MWh), highest emissions (tons), or highest emission rate (lbs/MWh). A ranking of 100 indicates the lowest absolute number or rate in any column.

		By Generation			By Tons of Emissions				By Emission Rates									
									All Generating Sources			Fossil Fuel Plants			Coal Plants			
Owner	Ownership Type	Total	Fossil	Coal	SO_2	NOx	CO_2	Hg	SO_2	NOx	CO_2	SO_2	NOx	CO_2	SO_2	NOx	CO_2	Hg
Los Angeles City	municipality	60	63	70	75	65	67	63	75	59	62	76	63	71	76	14	49	29
Lower CO River Authority	state power authority	70	57	58	50	67	56	45	38	55	36	44	66	58	36	70	33	35
LS Power	privately held corp.	93	78	75	76	82	82	64	73	77	61	77	81	76	68	74	1	3
MidAmerican	privately held corp.	10	7	5	15	3	5	6	41	17	37	43	18	30	54	18	31	39
Municipal Elec. Auth. of GA	municipality	65	85	65	57	72	78	72	52	69	69	33	62	45	40	67	56	72
NC Public Power	municipality	68	94	73	73	84	93	74	71	85	90	57	69	26	64	77	70	67
NE Public Power District	power district	47	64	44	31	30	47	41	23	13	49	11	2	10	18	6	21	45
New York Power Authority	state power authority	36	88	-	87	92	91	-	93	94	92	83	86	79	-	-	-	-
NextEra Energy	investor-owned corp.	3	4	60	30	25	14	70	69	73	85	69	73	77	35	61	42	70
NiSource	investor-owned corp.	54	44	32	26	36	33	26	8	25	5	14	38	12	16	40	6	13
NRG	investor-owned corp.	17	11	9	12	18	9	5	25	48	39	30	55	41	27	60	30	6
NV Energy	investor-owned corp.	40	29	62	68	52	46	59	68	54	57	72	65	74	66	13	24	38
Occidental	investor-owned corp.	59	47	-	92	83	72	-	91	84	68	93	87	82	-	-	-	-
OGE	investor-owned corp.	35	25	31	27	19	28	36	30	7	38	39	16	57	22	7	39	40
Oglethorpe	cooperative	39	56	47	45	62	50	68	50	64	63	35	60	43	40	67	55	71
Omaha Public Power District	power district	51	59	40	40	32	45	25	32	19	41	29	9	16	43	19	36	5
PG&E	investor-owned corp.	28	90	-	83	80	92	-	88	90	94	81	75	78	-	-	-	-
Pinnacle West	investor-owned corp.	31	37	37	61	26	39	34	65	22	59	65	8	55	71	5	40	26
PNM Resources	investor-owned corp.	61	66	57	65	41	58	52	61	24	46	64	20	47	69	12	27	44
Portland General Electric	investor-owned corp.	73	70	64	56	56	68	60	47	31	54	51	35	68	31	8	38	36
PowerSouth Energy Coop	cooperative	99	81	68	63	58	74	69	45	20	33	54	31	59	49	11	10	56
PPL	investor-owned corp.	11	9	6	9	6	7	8	27	30	44	23	29	33	32	39	69	43
Progress Energy	investor-owned corp.	9	8	14	14	13	10	18	40	53	53	38	56	65	26	48	63	52
PSEG	investor-owned corp.	19	23	41	42	34	26	54	63	70	81	60	68	72	46	47	48	59
PUD No 1 of Chelan County	power district	95	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PUD No 2 of Grant County	power district	91	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Puget Holdings	privately held corp.	76	72	61	66	59	64	71	60	43	47	63	48	62	63	33	16	74
Rockland Capital	privately held corp.	43	34	77	70	75	65	77	72	75	77	74	79	91	17	2	23	60
Sacramento Municipal Util Dist	municipality	97	87	-	90	93	90	-	87	92	84	86	94	85	-	-	-	-
Salt River Project	power district	34	30	25	53	22	30	24	55	14	43	58	7	34	61	10	28	18
San Antonio City	municipality	37	46	38	43	53	40	28	49	58	48	41	51	14	53	65	15	17
Santee Cooper	state power authority	30	24	20	35	40	24	51	46	52	32	52	61	37	57	71	62	76
SCANA	investor-owned corp.	33	32	34	24	48	36	42	24	57	52	18	59	64	12	57	74	58
Seminole Electric Coop	cooperative	71	58	50	51	73	55	65	37	67	27	46	76	52	50	78	67	68
Sempra	investor-owned corp.	48	48	-	84	87	76	-	86	91	82	88	93	87	-	-	-	-
Southern	investor-owned corp.	1	1	2	2	2	2	3	21	44	45	20	47	56	14	42	53	25
SUEZ Energy	foreign-owned corp.	57	49	74	72	74	73	76	74	72	76	75	78	81	60	51	20	73
TECO	investor-owned corp.	42	33	42	59	66	37	67	59	65	35	66	72	61	65	75	8	77
Tenaska	privately held corp.	63	52	-	85	81	77	-	83	81	71	85	84	84	-	-	-	-
Tennessee Valley Authority	federal power authority	6	6	4	4	5	4	7	33	50	60	16	36	22	23	45	47	50
TransAlta	foreign-owned corp.	78	74	53	69	43	52	39	66	12	11	71	14	3	78	20	4	23
TransCanada	foreign-owned corp.	100	86	-	78	79	85	-	77	71	74	78	74	75	-	-	-	-
Tri-State	cooperative	62	50	35	62	31	41	53	58	5	3	62	10	8	73	21	22	63
UniSource	investor-owned corp.	81	67	52	64	47	57	55	57	10	10	61	23	24	72	28	25	53
US Bureau of Reclamation	federal power authority	23	89	69	74	63	81	61	78	74	91	70	5	18	76	14	50	30
US Corps of Engineers	federal power authority	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
US Power Generating Company	privately held corp.	55	43	-	79	78	69	-	79	76	67	79	80	80	-	-	-	-
Westar	investor-owned corp.	29	26	21	48	20	23	20	54	15	24	59	17	13	67	26	13	21
Wisconsin Energy	investor-owned corp.	41	31	24	37	33	27	38	39	33	6	47	44	6	56	49	2	54
Xcel	investor-owned corp.	15	13	10	17	7	11	9	43	27	42	42	27	38	47	29	26	32

NOx and SO_2 Emissions Levels and Rates

Figures 11 through 14 display SO_2 and NOx emission levels and emission rates for fossil fuel-fired generating sources owned by each company.

"Fossil only" emission rates are calculated by dividing each company's total NOx and SO_2 emissions from fossil-fired power plants by its total generation from fossil-fired power plants. Companies with significant coal-fired generating capacity have the highest total emissions of SO_2 and NOx because coal contains higher concentrations of sulfur than natural gas and oil and coal plants generally have higher NOx emission rates.

Figures 11 through 14 illustrate wide disparities in the "fossil only" emission levels and emission rates of the 100 largest power producers. Their total fossil generation varies from 0 MWh to 164 million MWh and:

- SO_2 emissions range from 0 to 498,009 tons, and SO_2 emission rates range from 0 pounds per MWh to 11.4 pounds per MWh;
- NOx emissions range from 0 to 129,951 tons, and NOx emission rates range from 0 pounds per MWh to 4 pounds per MWh.

FIGURE 11

Fossil Fuel - NOx Total Emissions and Emission Rates

Total emissions (thousand tons) and emission rates (lbs/MWh) from fossil fuel generating facilities

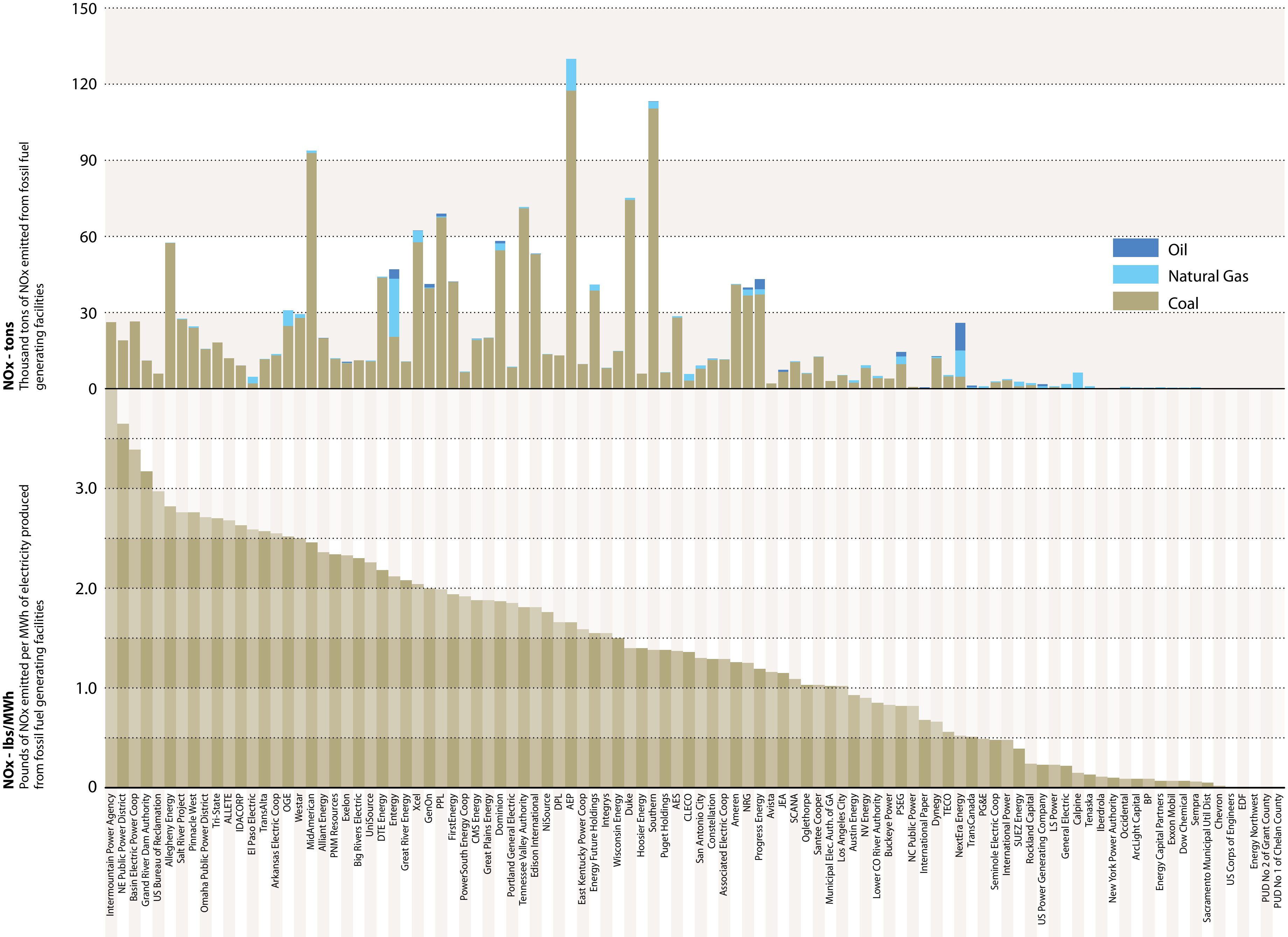


FIGURE 12

Fossil Fuel - NOx Total Emissions and Emission Rates

Total emissions (thousand tons) and emission rates (lbs/MWh) from fossil fuel generating facilities

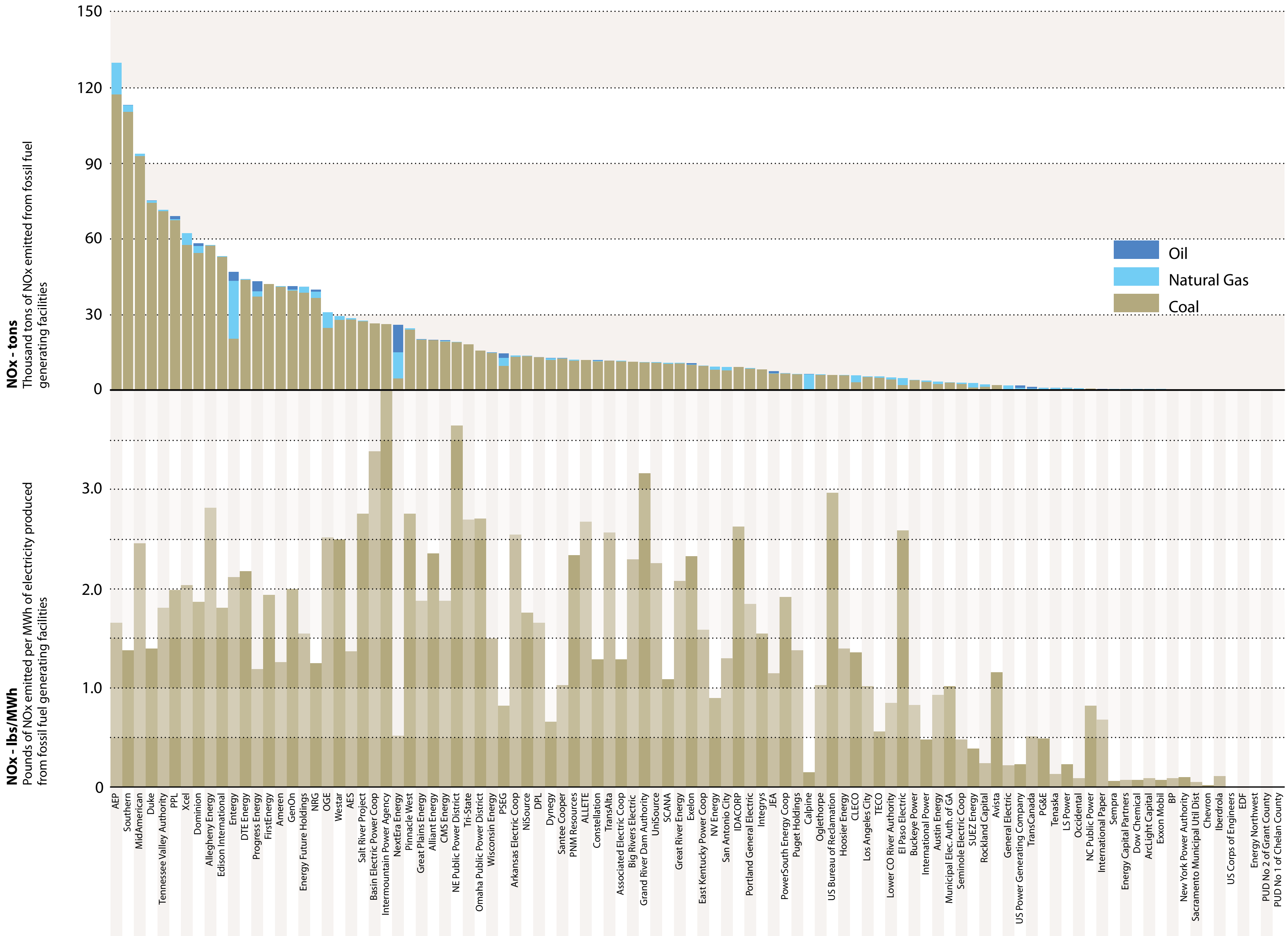


FIGURE 13

Fossil Fuel - SO_2 Total Emissions and Emission Rates
Total emissions (thousand tons) and emission rates (lbs/MWh) from fossil fuel generating facilities

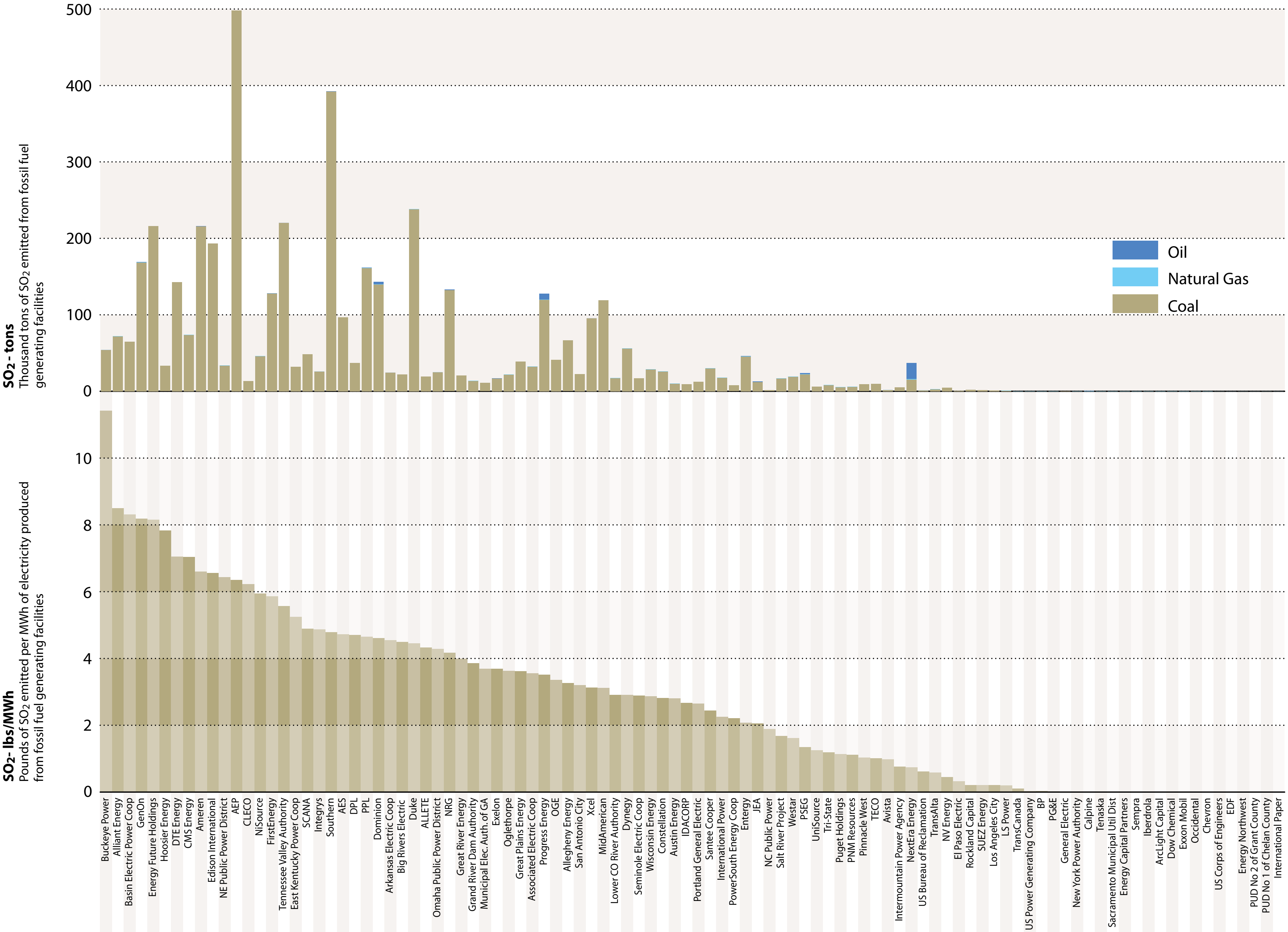
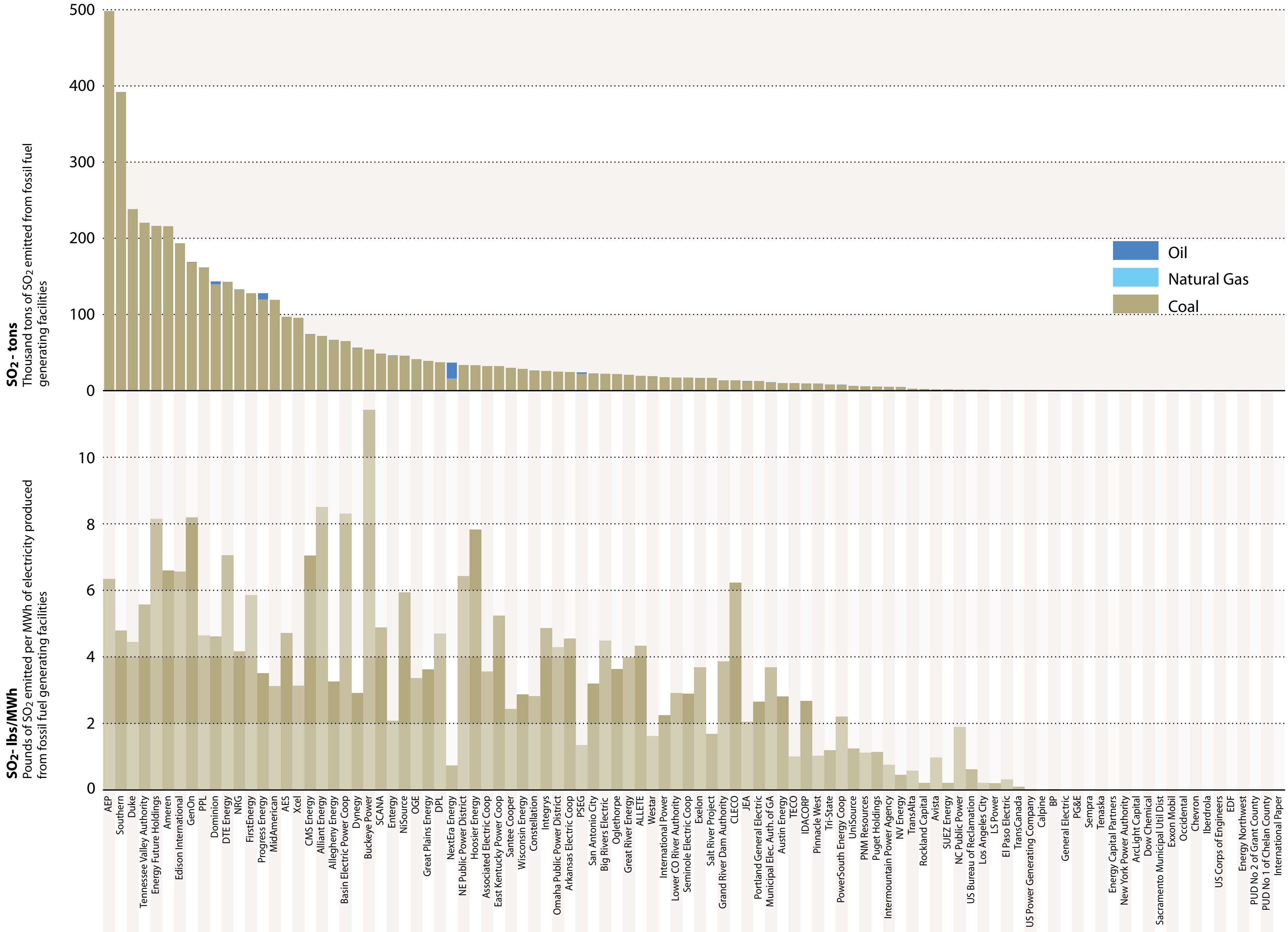


FIGURE 14

Fossil Fuel - SO_2 Total Emissions and Emission Rates

Total emissions (thousand tons) and emission rates (lbs/MWh) from fossil fuel generating facilities



CO_2 Emission Levels and Rates

Figures 15 and 16 display total CO_2 emission levels from coal, oil, and natural gas combustion and emission rates based on all generating sources owned by each company.

"All-source" emission rates are calculated by dividing each company's total CO_2 emissions by its total generation. In most cases, producers with significant non-emitting fuel sources, such as nuclear, hydroelectric and wind power, have lower all-source emission rates than producers owning primarily fossil fuel power plants. Among the 100 largest power producers:

- Coal-fired power plants are responsible for 82.6 percent of CO_2 emissions.
- Natural gas-fired power plants are responsible for 16 percent of CO_2 emissions.
- Oil-fired power plants are responsible 0.8 percent of CO_2 emissions.

Figures 15 and 16 illustrate wide disparities in the "all-source" emission levels and emission rates of the 100 largest power producers. Their total electric generation varies from 6.9 million MWh to 198 million MWh and their CO_2 emissions range from 0 to 155 million tons, and CO_2 emission rates range from 0 pounds per MWh to 2,360.5 pounds per MWh.

FIGURE 15

All Source - CO_2 Total Emissions and Emission Rates

Total emissions (million tons) and emission rates (lbs/MWh) from all generating facilities

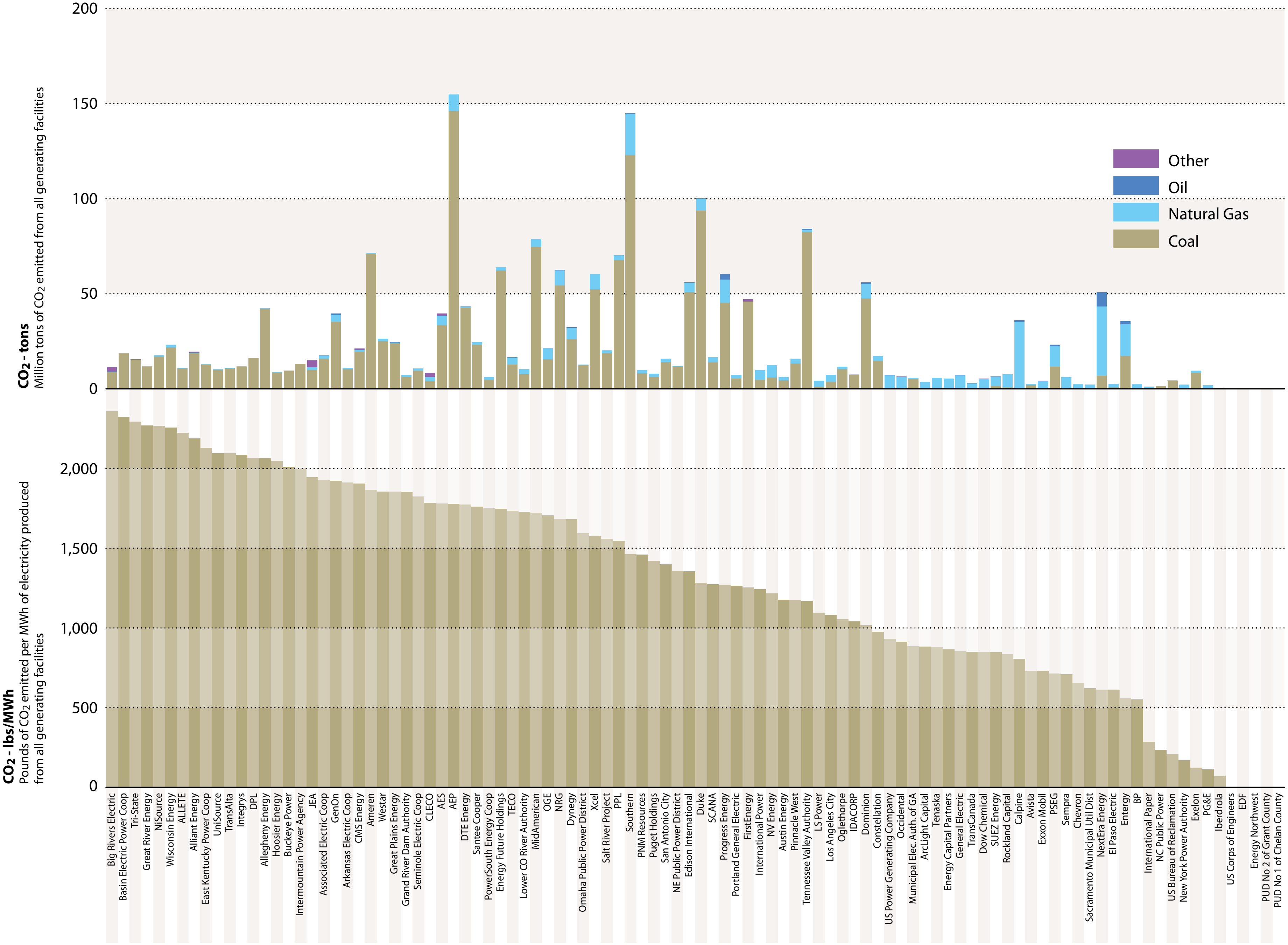
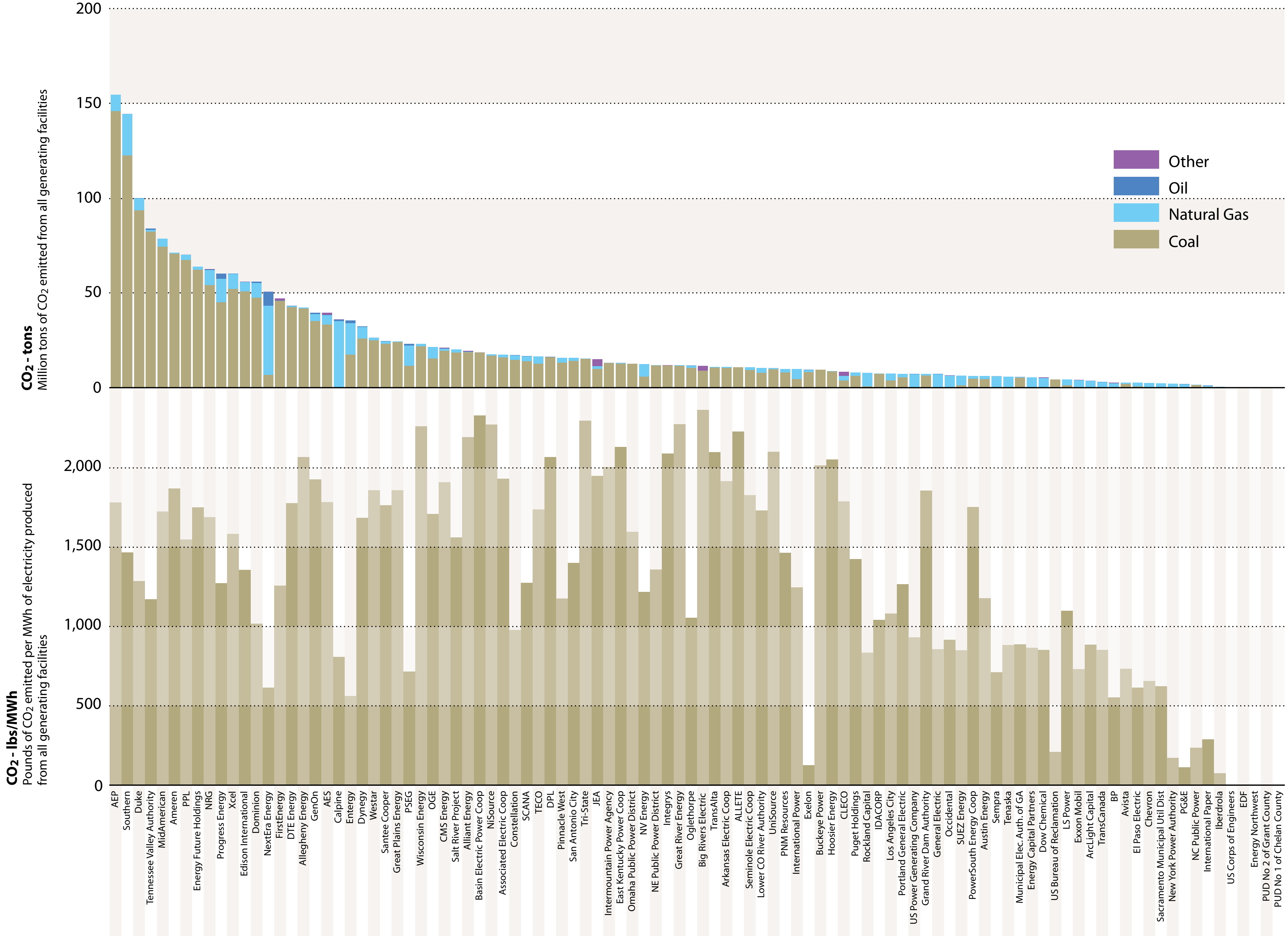


FIGURE 16

All Source - CO_2 Total Emissions and Emission Rates

Total emissions (million tons) and emission rates (lbs/MWh) from all generating facilities



Mercury Emission Levels and Rates

Figures 17 and 18 display total mercury emission levels and emission rates from coal-fired power plants.

In 2005, EPA issued rules regulating mercury emissions from coal-fired power plants. However, in February 2008, the DC Circuit found the rules invalid and they never took effect. EPA has since developed emissions standards for coal- and oil-fired electric generating units to regulate emissions of mercury and other hazardous air pollutants. The standards are scheduled to go into effect in 2015, assuming that there are no delays due to on-going legal challenges to the rule. The differences in mercury emission rates seen in the following figures are largely due to the mercury content and type of coal used, and the effect of control technologies designed to lower SO_2, NOx, and particulate emissions.

Coal mercury emissions from the top 100 power producers range from less than 1 pound to 6,398 pounds, and coal mercury emission rates range from 0.0001 pound per GWh to 0.127 pound per GWh.

FIGURE 17

Coal - Mercury Emission Rates and Total Emissions
Emission rates (lbs/GWh) and total emissions (pounds) from coal plants

1 gigawatt-hour (GWh) = 1,000 MWh

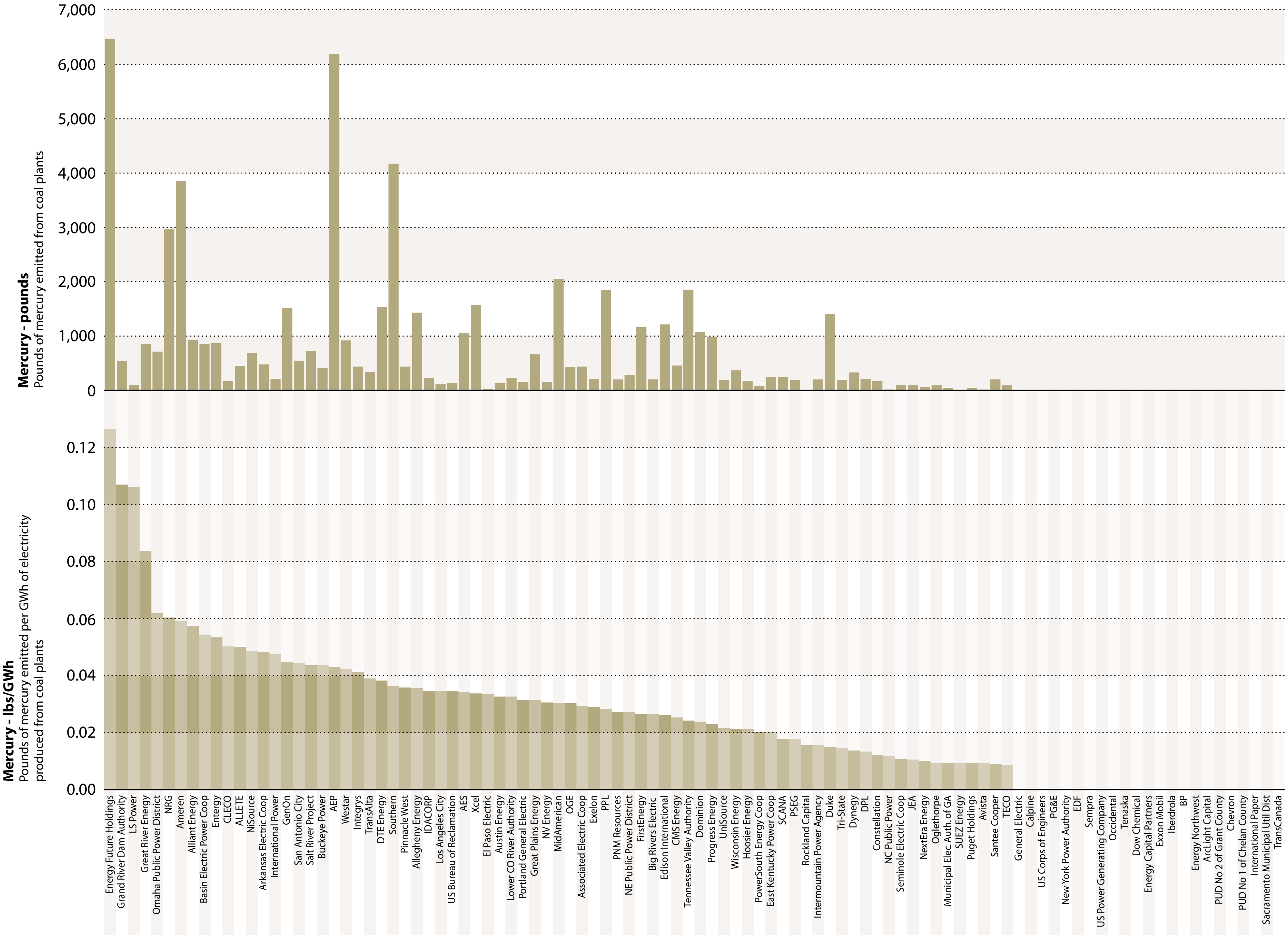
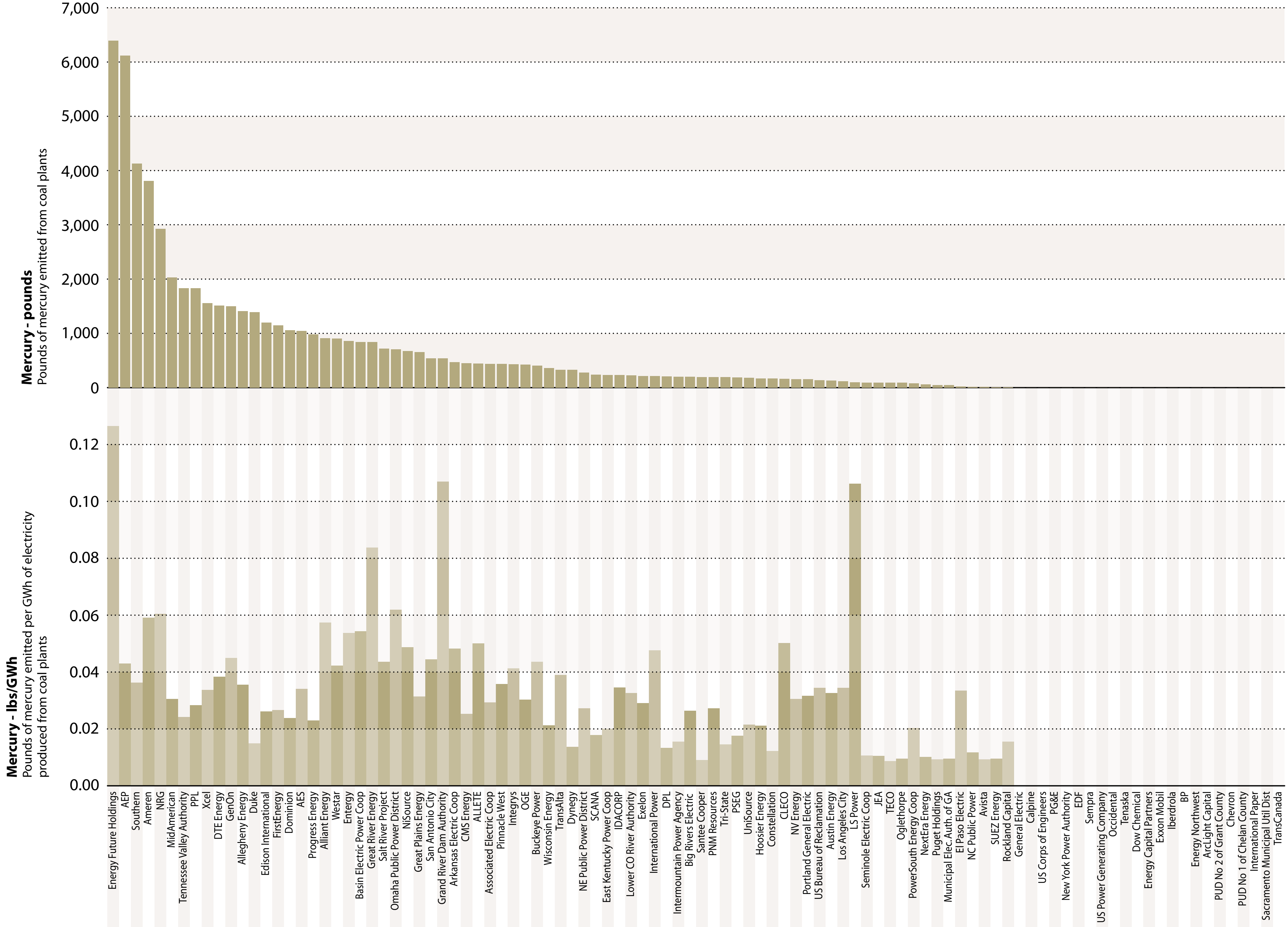
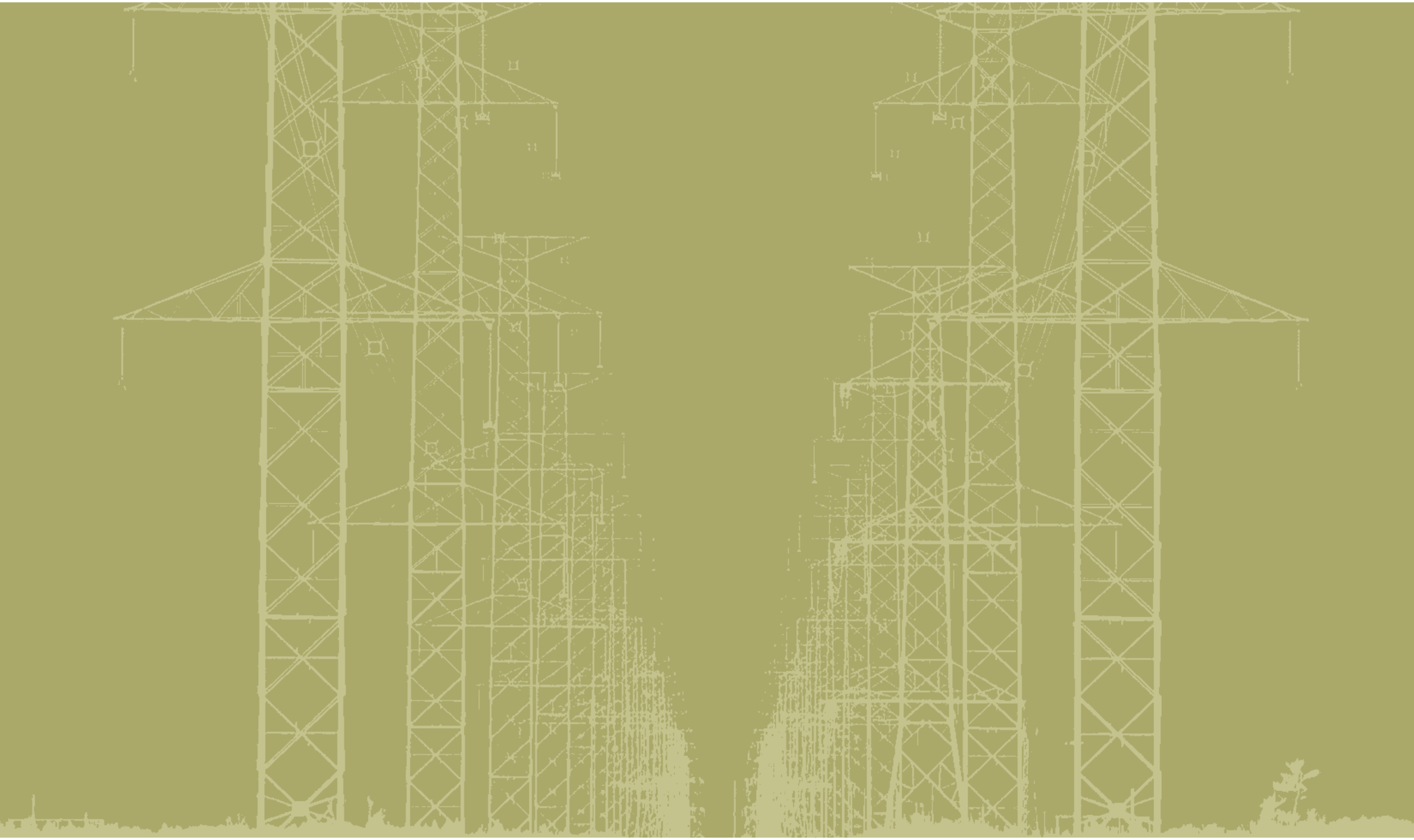


FIGURE 18

Coal - Mercury Total Emissions and Emission Rates
Total emissions (pounds) and emission rates (lbs/GWh) from coal plants

1 gigawatt-hour (GWh) = 1,000 MWh



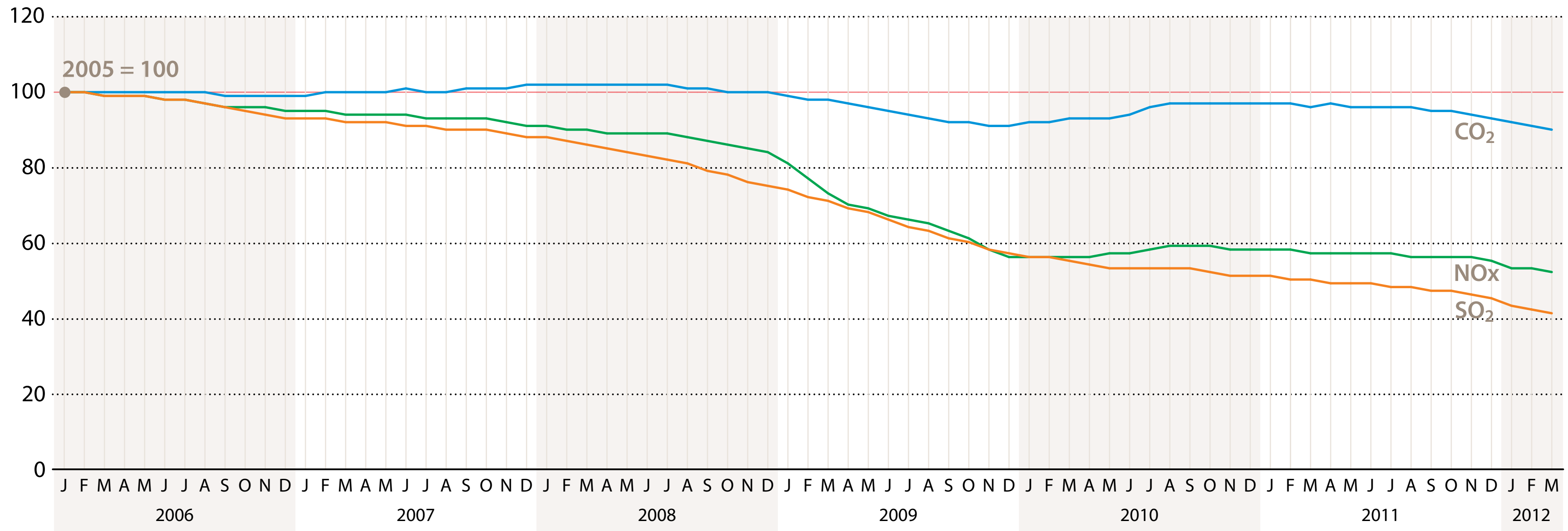


Preliminary 2011 Emissions Analysis

In preparing the Emissions Benchmarking report, we recognize that the past several years have been a particularly active period in terms of companies switching to lower emitting fuels and installing pollution control systems, as will the next several years. Unfortunately, there is a lag time in terms of the release of the data used in developing the benchmarking database, which prevents us from using 2011 and 2012 data in our comprehensive assessments. However, NOx, SO_2, and CO_2 emissions data for 2011 and the first quarter of 2012 are currently available. We used these more recent datasets to chart emission trends since 2005. Figure 19 plots the trends in power plant NOx, SO_2, and CO_2 emissions since 2005 (indexed 12-month moving totals[36]).

FIGURE 19

Annual Emission Levels: CO_2, NOx, SO_2
(12-month Moving Total Index: 2005 = 100)



SOURCE: MJB&A ANALYSIS; U.S. ENVIRONMENTAL PROTECTION AGENCY: AIR MARKETS PROGRAM DATA.

In the wake of the recent economic recession, power plant emissions declined significantly, in part due to a decline in overall electricity demand. Emissions then leveled off from 2010 through 2011, and now look to be resuming their downward trajectory. As detailed elsewhere in this report, the two major forces driving this recent drop in emissions are record low natural gas prices and an increased level of pollution controls installed at coal plants.

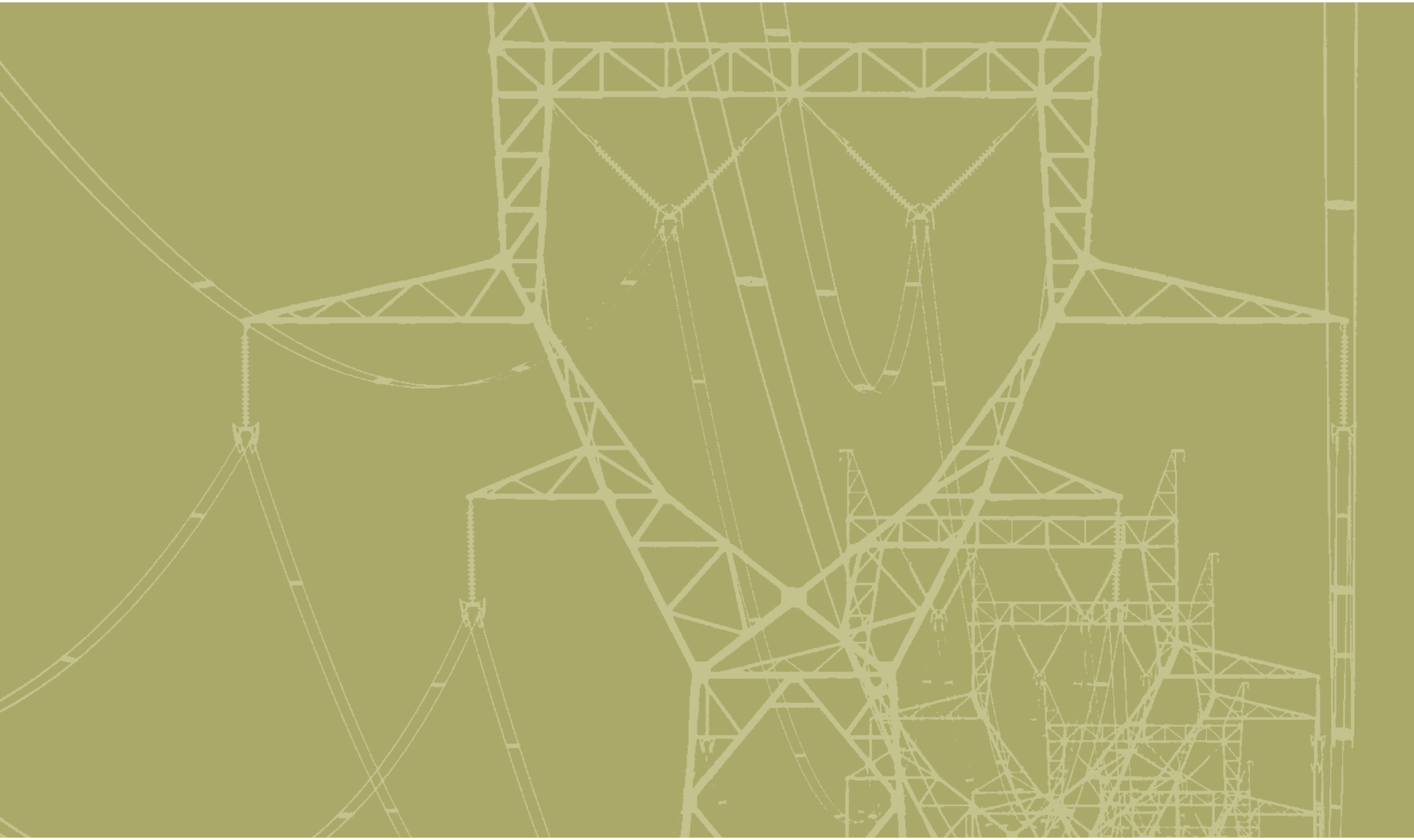
According to EPA, over 33 GW of coal capacity (over 10 percent of the existing total) was scheduled to bring scrubbers online in 2010 and 2011.[37] For example, John Amos (West Virginia), W H Sammis (Ohio), Coffeen (Illinois), and PSEG Hudson (New Jersey), four large coal plants that together account for about seven GW of generating capacity, installed scrubbers during this period. SO_2 emission levels at all three plants dropped by between 31 and 62 percent (over 2010 levels) in 2011.[38] Extending this analysis to all coal plants in the country, we find several cases where SO_2 and NOx emissions in 2011 declined sharply, without a corresponding drop in their total heat input or fuel burned. This suggests either new control equipment was installed at these plants or existing controls were utilized more often than before. Table 3 compares the total emissions in 2010 and 2011 of the 40 coal plants with the largest SO_2 and NOx emissions reductions in 2011. The percent reductions have been adjusted for changes in fuel consumption to highlight SO_2 and NOx reductions resulting from new controls and improved performance of existing controls. CO_2 emissions are directly proportional to the amount of fuel consumed; as a result the percent reductions indicate little or no change when adjusted for fuel consumption.

Future versions of the Benchmarking report will provide a full analysis of the 2011 data.

TABLE 5

Coal Plants with the Highest Emission Reductions
(ranked in order of capacity in MW)

			SO_2 (tons)				NOx (tons)				CO_2 (tons)			
	Plant Name	State	2010	2011	Change	Change (adj. for change in heat input)	2010	2011	Change	Change (adj. for change in heat input)	2010	2011	Change	Change (adj. for change in heat input)
	Total for all U.S. Coal Plants		**5,063,999**	**4,503,348**	**-11%**	**-5%**	**1,945,138**	**1,830,520**	**-6%**	**0%**	**2,020,478,166**	**1,882,985,943**	**-7%**	**-1%**
1	Scherer	GA	69,862	50,488	-28%	-23%	16,921	15,361	-9%	-5%	25,133,404	24,137,771	-4%	0%
2	John E Amos	WV	19,868	8,610	-57%	-57%	4,068	3,929	-3%	-4%	15,833,972	15,905,865	0%	0%
3	FirstEnergy W H Sammis	OH	12,761	4,202	-67%	-48%	11,496	7,635	-34%	-14%	14,134,825	10,472,587	-26%	-6%
4	Crystal River	FL	39,477	26,207	-34%	-25%	10,723	7,400	-31%	-22%	13,293,936	12,162,147	-9%	0%
5	J M Stuart	OH	9,805	8,441	-14%	-15%	7,990	7,759	-3%	-4%	13,726,752	14,562,270	6%	5%
6	Labadie	MO	66,794	57,947	-13%	-18%	9,796	9,890	1%	-4%	18,996,587	19,941,927	5%	0%
7	Jim Bridger	WY	13,654	9,689	-29%	-15%	17,008	13,175	-23%	-8%	16,278,550	13,978,254	-14%	0%
8	Widows Creek	AL	10,982	5,770	-47%	-30%	2,996	1,821	-39%	-21%	6,378,836	5,240,088	-18%	0%
9	Conesville	OH	16,558	9,456	-43%	-58%	7,797	8,885	14%	-1%	7,038,706	8,069,679	15%	0%
10	Mountaineer	WV	3,247	2,009	-38%	-53%	2,077	2,352	13%	-2%	7,894,102	9,080,293	15%	0%
11	Winyah	SC	4,997	3,510	-30%	-15%	3,386	2,767	-18%	-3%	6,805,933	5,781,215	-15%	0%
12	Coal Creek	ND	18,115	15,067	-17%	-15%	8,672	7,977	-8%	-6%	10,057,675	9,793,671	-3%	-1%
13	Crist	FL	4,449	2,847	-36%	-15%	7,905	4,380	-45%	-23%	6,432,627	5,053,003	-21%	0%
14	Merom	IN	11,940	8,813	-26%	-34%	4,016	3,327	-17%	-25%	7,016,806	7,577,743	8%	0%
15	Clay Boswell	MN	6,655	3,965	-40%	-54%	6,441	4,715	-27%	-40%	7,219,474	8,294,020	15%	2%
16	George Neal North	IA	21,662	14,445	-33%	-20%	9,497	7,624	-20%	-6%	7,295,257	6,313,261	-13%	0%
17	Coffeen	IL	211	83	-61%	-62%	1,586	1,450	-9%	-9%	5,980,177	6,030,638	1%	0%
18	Stanton Energy Center	FL	4,487	2,394	-47%	-28%	6,525	5,057	-22%	-4%	6,038,423	4,897,215	-19%	0%
19	Coronado	AZ	11,722	7,352	-37%	-28%	12,625	10,186	-19%	-10%	7,307,274	6,594,556	-10%	0%
20	Dave Johnston	WY	13,321	11,306	-15%	-19%	7,347	7,181	-2%	-6%	5,992,190	6,227,910	4%	0%
21	Cliffside	NC	12,217	308	-97%	-100%	864	709	-18%	-20%	2,490,794	2,544,261	2%	0%
22	E W Brown	KY	20,922	1,023	-95%	-84%	5,691	4,766	-16%	-6%	3,395,497	3,031,044	-11%	0%
23	Milton R Young	ND	27,099	5,918	-78%	-98%	11,605	11,471	-1%	-21%	5,473,220	6,553,771	20%	0%
24	Harding Street	IN	21,666	18,994	-12%	-30%	2,606	2,616	0%	-17%	3,516,724	4,053,075	15%	-2%
25	Sandow Station	TX	1,498	1,548	3%	-18%	1,329	1,286	-3%	-24%	3,595,856	4,357,144	21%	0%
26	PSEG Hudson Generating Station	NJ	1,727	987	-43%	-31%	2,071	752	-64%	-52%	2,301,874	1,953,338	-15%	-3%
27	PSEG Mercer Generating Station	NJ	8,564	571	-93%	-41%	892	424	-52%	0%	2,131,872	977,848	-54%	-2%
28	Cane Run	KY	9,488	7,824	-18%	-16%	5,957	5,595	-6%	-4%	3,622,682	3,492,071	-4%	-2%
29	Cheswick Power Plant	PA	11,806	9,290	-21%	-59%	2,522	3,293	31%	-7%	1,940,009	2,672,465	38%	0%
30	Williams	SC	947	607	-36%	-15%	2,023	1,527	-25%	-4%	3,378,221	2,671,380	-21%	0%
31	Coleto Creek	TX	17,616	13,694	-22%	-16%	3,234	2,634	-19%	-12%	4,561,945	4,277,773	-6%	0%
32	State Line Energy	IN	10,567	8,044	-24%	-18%	8,240	7,002	-15%	-9%	3,485,817	3,289,531	-6%	0%
33	Bailly	IN	9,162	2,560	-72%	-89%	2,752	1,972	-28%	-45%	2,660,841	3,106,647	17%	0%
34	Trimble County	KY	1,707	3,110	82%	-15%	1,104	2,013	82%	-15%	3,996,625	7,972,343	99%	2%
35	Charles R Lowman	AL	6,661	4,301	-35%	-34%	6,142	3,189	-48%	-47%	3,841,266	3,797,055	-1%	0%
36	Gibbons Creek	TX	12,146	2,650	-78%	-73%	2,277	2,115	-7%	-2%	3,700,104	3,507,282	-5%	0%
37	R D Morrow	MS	7,612	3,302	-57%	-33%	6,101	4,578	-25%	-2%	2,619,368	2,008,396	-23%	0%
38	C P Crane	MD	5,589	5,682	2%	-16%	2,450	2,498	2%	-16%	1,035,469	1,242,442	20%	2%
39	Wyodak	WY	6,768	2,387	-65%	-39%	4,221	2,409	-43%	-17%	3,199,282	2,365,139	-26%	0%
40	Genoa	WI	8,874	3,297	-63%	-18%	1,609	706	-56%	-11%	1,767,918	970,264	-45%	0%



Use of the Benchmarking Data

This report provides public information that can be used to evaluate electric power producers' emissions performance and risk exposure. Transparent information on emissions performance is useful to a wide range of decision-makers, including electric companies, financial analysts, investors, policymakers, and consumers.

Electric Companies

This provision of transparent information supports corporate self-evaluation and business planning by providing a useful "reality check" that companies can use to assess their performance relative to key competitors, prior years and industry benchmarks. By understanding and tracking their performance, companies can evaluate how different business decisions may affect emissions performance over time, and how they may more appropriately consider environmental issues in their corporate policies and business planning.

This report is also useful for highlighting the opportunities and risks companies may face from environmental concerns and potential changes in environmental regulations. Business opportunities may include increasing the competitive advantage of existing assets, the chance to generate or enhance revenues from emission trading mechanisms, and opportunities to increase market share by pursuing diversification into clean energy. Corporate risks that could have severe financial implications include a loss of competitive advantage or decrease in asset value due to policy changes, risks to corporate reputation, and the risk of exposure to litigation arising from potential violations of future environmental laws and regulations. Becoming aware of a company's exposure to these opportunities and risks is the first step in developing effective corporate environmental strategies.

Investors

The financial community and investors in the electric industry need accurate information concerning environmental performance in order to evaluate the financial risks associated with their investments and to assess their overall value. Air emissions information is material to investors and can be an important indicator of a company's management.

Evaluation of financial risks associated with SO_2, NOx and mercury has become a relatively routine corporate practice. By comparison, until recent years, corporate attention and disclosure of business impacts related to CO_2 has been more limited. This is likely to change with the U.S. Securities and Exchange Commission's (SEC) issuance, in January 2010, of interpretive guidance concerning corporate climate risk disclosure. All publicly-traded companies in the U.S. are required to disclose climate-related "material" effects on business operations – whether from new emissions management policies, the physical impacts of changing weather or business opportunities associated with the growing clean energy economy – in their annual SEC filings. Despite the SEC's guidance, not all publically traded companies mentioned climate change in their most recent annual Form 10-K filings. As a result, some have concluded that SEC requirements must be strengthened to ensure companies meet the expectations of their investors to disclose climate-related risks.

Numerous studies have pointed to the growing financial risks of climate change issues for all firms, especially those within the electric industry. Changing environmental requirements can have important implications for long-term share value, depending on how the changes affect a company's assets relative to its competitors. Especially in the context of climate change, which poses considerable uncertainty and different economic impacts for different types of power plants, a company's current environmental performance can shed light on its prospects for sustained value.

As the risks associated with climate change have become clearer and the prospect of regulation more imminent, the financial implications of climate change for the electric industry have drawn the attention of Wall Street. Ratings agencies such as Moody's Investors Service and Standard and Poor's have issued reports analyzing the credit impacts of climate change for the power sector. In its Annual Industry Outlook published in January 2010, Moody's identified "regulatory risks… from increasingly stringent environmental mandates, especially potential carbon dioxide emission restrictions" as a key longer-term challenge for the industry.[39] In a February 2012 news release, Moody's identified environmental regulations as both a risk and opportunity for the industry. "Older coal plants face large capital costs for new emission control equipment that is unlikely to be recovered in today's depressed energy margins. On the other hand, newer gas-fired generation, renewable energy, nuclear, and fully scrubbed coal-fired plants are likely to benefit over the long term due to shrinking reserve margins."[40] In May 2012, Standard and Poor's Rating

Services predicted that over the next several years, "More-stringent environmental regulations for power plants [will] make it less likely that new coal-fired generation plants will be built in the U.S., creating doubt for future coal demand."[41] Mainstream financial firms such as Citigroup and Sanford C. Bernstein have issued reports evaluating the company-specific financial impacts of different regulatory scenarios on electric power companies and their shareholders.[42, 43]

Shareholder concern about the financial impacts of climate change has increased significantly over the past decade. Much of this concern is directed toward encouraging electric companies to disclose the financial risks associated with climate change, particularly the risks associated with the future regulation of CO_2. The Carbon Disclosure Project (CDP) was launched in 2000 and annually requests climate change information from companies. CDP now represents 655 institutional investors with combined assets of over $78 trillion under management, and, as of 2012, requests climate strategy and greenhouse gas emissions data from over 3,000 of the world's largest companies. In addition to its original Climate Change Program, CDP also recently introduced Supply Chain and Water Disclosure Programs that gather information from 50 and 190 companies, respectively. Since 2011, CDP has moved towards scoring companies not only on the comprehensiveness of their carbon disclosure, but also on their performance to combat climate change through mitigation, adaptation, and transparency. CDP notes that the performance score is a developing metric.

In 2003, the Investor Network on Climate Risk (INCR) was launched to promote better understanding of the risks of climate change among institutional investors. INCR, which now numbers 100 institutional investors representing assets of $10 trillion, encourages companies in which its members invest to address and disclose material risks and opportunities to their businesses associated with climate change and a shift to a lower carbon economy.

Shareholders have demonstrated increasing support for proxy resolutions requesting improved analysis and disclosure of the financial risks companies face from CO_2 emissions and their strategies for addressing these risks. In response to shareholder activity, more than a dozen of the largest U.S. electric power companies have issued reports for investors detailing their climate-related business risks and strategies. Shareholders continue to file resolutions with electric power companies that have not yet disclosed this information. According to the Investor Network on Climate Risk, at least 66 shareholder resolutions relating to climate and environmental issues at more than 40 oil, coal, and electric power companies were filed in the 2011 proxy season, a 50 percent increase over the number filed in 2010.

Policymakers

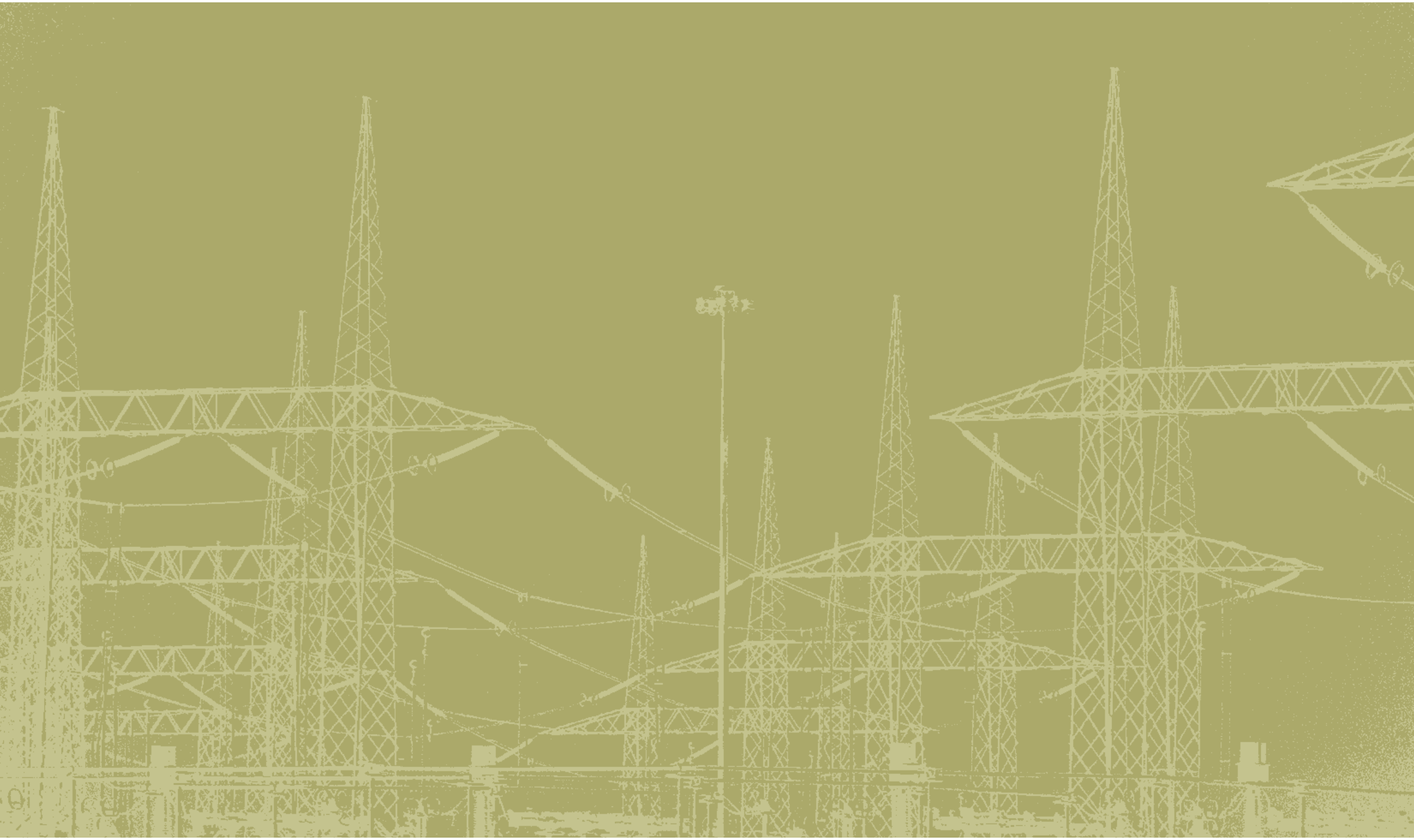
The information on emissions contained in this report is useful to policymakers who are working to develop long-term solutions to the public health and environmental effects of air pollutant emissions. The outcomes of federal policy debates concerning various regulatory and legislative proposals to improve power plant emissions performance will impact the electric industry, either in regard to the types of technologies or fuels that will be used at new power plant facilities or the types of environmental controls that will be installed at existing facilities.

Information about emissions performance helps policymakers by indicating which pollution control policies have been effective (e.g., SO_2 reductions under the Clean Air Act's Acid Rain Program), where opportunities may exist for performance and environmental improvements (e.g., SO_2 and NOx emissions performance standards for large, older facilities under the Regional Haze Rule), and where policy action is required to achieve further environmental gains (e.g., the environmental and financial risks associated with climate change).

Electricity Consumers

Finally, the information in this report is valuable to electricity consumers. Accurate and understandable information on emissions promotes public awareness of the difference in environmental performance and risk exposure. In jurisdictions that allow consumers to choose their electricity supplier, this information enables consumers to consider environmental performance in power purchasing decisions. This knowledge also enables consumers to hold companies accountable for decisions and activities that affect the environment and/or public health and welfare.

The information in this report can also help the public verify that companies are meeting their environmental commitments and claims. For example, some electric companies are establishing voluntary emissions reduction goals for CO_2 and other pollutants, and many companies are reporting significant CO_2 emission reductions from voluntary actions. Public information is necessary to verify the legitimacy of these claims. Public awareness of companies' environmental performance supports informed public policymaking by promoting the understanding of the economic and environmental tradeoffs of different generating technologies and policy approaches.



Appendix A
Data Sources, Methodology and Quality Assurance

This report examines the air pollutant emissions of the 100 largest electricity generating companies in the United States based on 2010 electricity generation, emissions and ownership data. The report relies on publicly-available information reported by the U.S. Energy Information Administration (EIA), U.S. Environmental Protection Agency (EPA), Securities and Exchange Commission (SEC), state environmental agencies, company websites, and media articles.

Data Sources

The following public data sources were used to develop this report:

EPA AIR MARKETS PROGRAM DATA (AMP): EPA's Air Markets Program Data account for almost all of the SO_2 and NOx emissions, and about 75 percent of the CO_2 emissions analyzed in this report. These emissions were compiled using EPA's on-line emissions database available at http://http://ampd.epa.gov/ampd/.

EPA TOXICS RELEASE INVENTORY (TRI): Power plants and other facilities are required to submit reports on the use and release of certain toxic chemicals to the TRI. The 2010 mercury emissions used in this report are based on TRI reports submitted by facility managers and which are available at http://http://iaspub.epa.gov/triexplorer/tri_release.chemical.

EIA FORMS 923 POWER PLANT DATABASES (2010): EIA Form 923 provided almost all of the generation data analyzed in this report. EIA Form 923 provides data on the electric generation and heat input by fuel type for utility and non-utility power plants. The heat input data was used to calculate approximately 25 percent of the CO_2 emissions analyzed in this report. The form is available at http://www.eia.doe.gov/cneaf/electricity/page/eia906_920.html.

EIA FORM 860 ANNUAL ELECTRIC GENERATOR REPORT (2010): EIA Form 860 is a generating unit level data source that includes information about generators at electric power plants, including information about generator ownership. EIA Form 860 was used as the primary source of power plant ownership for this report. The form is available at http://www.eia.doe.gov/cneaf/electricity/page/eia860.html.

EPA U.S. INVENTORY OF GREENHOUSE GAS EMISSIONS AND SINKS (2012): EPA's U.S. Inventory of Greenhouse Gas Emissions and Sinks report provides in Annex 2 heat contents and carbon content coefficients of various fuel types. This data was used in conjunction with EIA Form 923 to calculate approximately 25 percent of the CO_2 emissions analyzed in this report. Annex 2 is available http://epa.gov/climatechange/emissions/downloads12/US-GHG-Inventory-2012-Annex-2-Emissions-from-Fossil-Fuel-Combustion.pdf.

Plant Ownership

This report aims to reflect power plant ownership as of December 31, 2010. Plant ownership data used in this report are primarily based on the EIA-860 database from the year 2010. EIA-860 includes ownership information on generators at electric power plants owned or operated by electric utilities and non-utilities, which include independent power producers, combined heat and power producers, and other industrial organizations. It is published annually by EIA.

For the largest 100 power producers, plant ownership is further checked against self-reported data from the producer's 10-K form filed with the SEC, listings on their website, and other media sources. Ownership of plants is updated based on the most recent data available. Consequently, in a number of instances, ultimate assignment of plant ownership in this report differs from EIA-860's reported ownership. This primarily happens when the plant in question falls in one or more of the categories listed below:

1. It is owned by a limited liability partnership shareholders of which are among the 100 largest power producers.
2. The owner of the plant as listed in EIA-860 is a subsidiary of a company that is among the 100 largest power producers.
3. It was sold or bought during the year 2010. Because form 10-K for a particular year is usually filed by the producer in the first quarter of the following year, this report assumes that ownership as reported in form 10-K is more accurate.

Power plant ownership reflected in this report does not include power purchase agreements.

Identifying "who owns what" in the dynamic electricity generation industry is probably the single most difficult and complex part of this report. In addition to the categories listed above, shares of power plants are regularly traded and producers merge, reorganize, or cease operations altogether. While considerable effort was expended in ensuring the accuracy of ownership information reflected in this report, there may be inadvertent errors in the assignment of ownership for some plants where public information was either not current or could not be verified.

Generation Data and Cogeneration Facilities

Plant generation data used in this report come from EIA Form 923.

Cogeneration facilities produce both electricity and steam or some other form of useful energy. Because electricity is only a partial output of these plants, their reported emissions data generally overstate the emissions associated with electricity generation. Generation and emissions data included in this report for cogeneration facilities have been adjusted to reflect only their electricity generation. For all such cogeneration facilities emissions data were calculated on the basis of heat input of fuel associated with electricity generation only. Consequently, for all such facilities EIA form 923, which report a plant's total heat input as well as that which is associated with electricity production only, was used to calculate their emissions.

NOx and SO_2 Emissions

The EPA AMP database collects and reports SO_2 and NOx emissions data for nearly all major power plants in the U.S. Emissions information reported in the AMP database is collected from continuous emission monitoring (CEM) systems. SO_2 and NOx emissions data reported to the AMP account for all of the SO_2 and NOx emissions assigned to the 100 largest power producers in this report.

The AMP database collects and reports SO_2 and NOx emissions data by fuel type at the boiler level. This report consolidates this data at the generating unit and plant levels. In the case of jointly owned plants, because joint ownership is determined by producer's share of installed capacity, assignment of SO_2 and NOx emissions to the producers on this basis implicitly assumes that emission rates are uniform across the different units. This may cause producers to be assigned emission figures that are slightly higher or lower than their actual shares.

CO_2 Emissions

CO_2 emissions reported through the EPA AMP account for approximately 75 percent of the CO_2 emissions used in this report. The remaining 25 percent was calculated using heat input data from EIA form 923 and carbon content coefficients of various fuel types provided by EPA. Table A.1 shows the carbon coefficients used in this procedure. Non-emitting fuel types, whose carbon coefficients are zero, are not shown in the table.

EIA form 923 reports heat input data by fuel type at the prime mover level. This report consolidates that data at the generating unit and plant levels. In the case of jointly owned plants, because joint ownership is determined by producer's share of installed capacity, assignment of CO_2 emissions to the producers on this basis implicitly assumes that emission rates are uniform across the different units. This may cause producers to be assigned emission figures that are slightly higher or lower than their actual shares.

TABLE A.1

Carbon Content Co-efficients by Fuel Type

FUEL TYPE	CARBON CONTENT COEFFICIENTS (Tg Carbon/Qbtu)
COAL	
Anthracite Coal and Bituminous Coal	25.44
Lignite Coal	26.65
Sub-bituminous Coal	26.50
Waste/Other Coal (includes anthracite culm, bituminous gob, fine coal, lignite waste, waste coal)	26.05
Coal-based Synfuel (including briquettes, pellets, or extrusions, which are formed by binding materials or processes that recycle materials)	25.34
OIL	
Distillate Fuel Oil (Diesel, No. 1, No. 2, and No. 4 Fuel Oils)	20.17
Jet Fuel	19.70
Kerosene	19.96
Residual Fuel Oil (No. 5, No. 6 Fuel Oils, and Bunker C Fuel Oil)	20.48
Waste/Other Oil (including Crude Oil, Liquid Butane, Liquid Propane, Oil Waste, Re-Refined Motor Oil, Sludge Oil, Tar Oil, or other petroleum-based liquid wastes)	20.55
Petroleum Coke	27.85
GAS	
Natural Gas	14.46
Blast Furnace Gas	18.55
Other Gas	18.55
Gaseous Propane	14.46

Mercury Emissions

Mercury emissions data for coal power plants presented in this report were obtained from EPA's Toxics Release Inventory (TRI). Mercury emissions reported to the TRI are based on emission factors, mass balance calculations or data monitoring. The TRI contains facility-level information on the use and environmental release of chemicals classified as toxic under the Clean Air Act. Because coal plants are the primary source of mercury emissions within the electric industry, the mercury emissions and emission rates presented in this report reflect the emissions associated with each producer's fleet of coal plants only.

Endnotes

1. Private entities include investor-owned and privately held utilities and non-utility power producers (e.g., independent power producers). Cooperative electric utilities are owned by their members (i.e., the consumers they serve). Publicly-owned electric utilities are nonprofit government entities that are organized at either the local or state level. There are also several federal electric utilities in the United States, such as the Tennessee Valley Authority.

2. SO_2 and NOx emissions data from U.S. Environmental Protection Agency (EPA), *National Emissions Inventory (NEI) Air Pollutant Emissions Trends Data,* October 2011. http://www.epa.gov/ttnchie1/trends/ (accessed June 18, 2012)
   CO_2 emissions data from EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2010,* at p. ES-7, April 2012. http://www.epa.gov/climatechange/emissions/downloads12/US-GHG-Inventory-2012-Main-Text.pdf (accessed June 18, 2012)
   Mercury emissions data from, EPA, U.S. EPA *Toxics Release Inventory Reporting Year 2010 National Analysis: Overview* at p. 7. January 2012. http://www.epa.gov/tri/tridata/tri10/nationalanalysis/overview/2010TRINAOverview.pdf (accessed June 18, 2012)

3. U.S. Energy Information Administration (EIA), *Utility, Non-utility, and Combined Heat & Power Plant Data Files* (EIA 923). 2010

4. The Atlanta Journal-Constitution, *Natural gas surpasses coal in Southern Co.'s energy mix,* April 25, 2012.

5. See, for example, AEP's decision to withdraw its $1 billion plan to retrofit the Big Sandy power plant in Kentucky.

6. EIA, *Spot natural gas prices near ten year lows during winter 2011-2012,* April 19, 2012.

7. Id.

8. Credit Suisse, *E&P Sector Launch - 2012: Year of the Water Dragon in E&P,* February 6, 2012.

9. EIA, *Horizontal drilling boosts Pennsylvania's natural gas production,* May 23, 2012.

10. EPA, *Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews,* April 17, 2012 (signed).

11. The Hill, *Obama order coordinates federal oversight of 'fracking' gas development,* April 13, 2012.

12. M.J. Bradley & Associates LLC (MJB&A), *Retirement Tracking Database,* May 17, 2012. (This includes units that are mothballed.)

13. The average size and age of the units that have announced plans to retire since January 2010, is 150 MW and 53 years, respectively.

14. Susan F. Tierney, *Why Coal Plants Retire: Power Market Fundamentals as of 2012,* February 16, 2012.

15. Id.

16. EIA, *U.S. coal consumption fell while exports increased during the fourth quarter of 2011,* April 25, 2012.

17. Id.

18. EIA, *Electric Power Monthly,* March 2012. (Percentages based on Table 1.1, preliminary 2011 data.)

19. EIA, *Short Term Energy Outlook,* May 2012.

20. American Wind Energy Association, *U.S. Wind Industry Annual Market Report Year Ending 2009,* April 10, 2010.

21. American Council for an Energy-Efficient Economy (ACEEE), *Opportunity Knocks: Examining Low-Ranking States in the State Energy Efficiency Scorecard,* May 2012.

22. ISO New England, *Draft Final Energy Efficiency Forecast,* 2015-2021, March 2012.

23. Consortium for Energy Efficiency, *State of the Efficiency Program Industry-Budgets, Expenditures, and Impacts 2011,* March 14, 2012.

24. Id.

25. Id.

26. Id.

27. PJM, 2015/2016 RPM *Base Residual Auction Results,* May 18, 2012.

28. ACEEE, *Energy Efficiency Resource Standards,* http://www.aceee.org/topics/eers (accessed June 18. 2012)

29. Id.

30. Monitoring Analytics (PJM Market Monitor), *PJM State of the Market Report 2011*

31. EIA, *Wholesale electricity prices mostly lower in 2011,* January 11, 2012.

32. MJB&A, *supra* n.12.

33. EIA, *Annual Energy Outlook 2011,* April 26, 2011. (Low Gas Price, Retrofit Required 20 Scenario. This scenario is projected to result in 48.4 GW of coal plant retirements (Reference and Policy Case combined). This is higher than the current level of announced retirements, but not far off.)

34. Id.

35. Southern Company, *Summary Annual Report: 2011 and Vogtle Units 3 and 4 project website.* (accessed June 19, 2012)
American Electric Power (AEP), *Analyst & Investor Meeting,* New York, NY, February 10, 2012.
Tennessee Valley Authority, *TVA Website: Fossil Generation Development & Construction Projects.* (accessed June 19, 2012)
NextEra Energy, Profile 2012. *Cape Canaveral Next Generation Clean Energy Center and Riviera Beach Next Generation Clean Energy Center webpages.* (accessed June 19, 2012)
Exelon Corporation, *Exelon Corporation and Constellation Energy merger fact sheet.*
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Edison International, *Q1 2012 Earnings Conference,* May 4, 2012.

Ameren, *News articles and Ameren Missouri 2011 IRP.*
Xcel, *Website: Clean Air-Clean Jobs Plan.* (accessed June 19, 2012)

36. 12-month moving totals are a simple way of controlling for seasonality and data points that are outliers. It also allows for the inclusion of the most recent monthly emissions data. The 12-month moving total for a given month is the total for the preceding 12 months. For example, the 12-month moving total for February of 2012 is obtained by adding up monthly emissions from the beginning of March 2011 until the end of February 2012.

37. EPA, *National Electric Energy Data System (v 4.10_MATS),* December 2011.

38. Total fuel burned, as indicated by total heat input, in 2010 and 2011 at these three plants are mostly unchanged or differ by an amount that is markedly less than the reduction in their respective SO_2 emissions. This suggests that the SO_2 reductions are due to new pollution control equipment coming online or existing ones being run harder, and not because of a lower utilization rate.

39. Moody's, *Annual Outlook: U.S. Electric Utilities Face Challenges Beyond Near-Term,* January 2010.

40. Public Power Weekly. *Moody's: Outlook remains mixed for power project sector,* February 27, 2012.

41. Wall Street Journal, *S&P Cuts Consol Energy's Outlook Amid Coal-Industry Challenges,* May 4, 2012.

42. Bernstein Research, *U.S. Utilities: Which Utilities Are Most at Risk from Pending Plant Retirements?,* 23 April 2008.

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