Regulation of Coal-Fired Electric Power Under U.S. Law

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Abstract: Coal-fired power generation in the United States is facing significant new economic and regulatory pressures that are changing its role in the electric generation mix. This chapter examines the regulation of coal mining and combustion, focusing on regulatory trends and economic considerations that are likely to have the largest impacts on coal’s future as an electric generation fuel. As gas becomes cost-competitive with coal as an electricity generation fuel, it is commanding a growing share of the electric generation market, usually at the expense of coal. Increasingly stringent regulation of the environmental externalities associated with coal mining and coal combustion seem likely to hasten this trend. This chapter outlines those recent and pending regulatory changes.

Key words: energy, environment, air pollution, water pollution

Coal-fired generation has traditionally commanded the lion’s share of electricity production in the United States. Coal’s historical dominance in the electric generation market is attributable to the fact that the price of coal has been relatively low and stable over the years. The U.S. Energy Information Administration projects that coal-fired power will retain a significant share of the American electricity supply into the future (as will nuclear power), but natural gas and renewables will continue to command increasing shares of supply. Indeed, additions to American electric generating capacity from gas-fired and renewable sources have each outpaced additions of new coal-fired capacity in recent years; and in April 2012, coal-fired power’s share of American electricity generation fell below that of natural gas for the first time.

This trend is due to the declining price of natural gas in the United States, declining prices and

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2 U.S. Energy Information Administration, annual energy Outlook 2012 (early release), available at http://www.eia.gov/forecasts/aeo/er/. In the American electricity markets, these fuels and technologies compete against one another for electricity customers. In most American wholesale electricity markets electric generating plants are "dispatched" – that is, they are authorized to supply power to customers over the electric grid – on a marginal cost basis, with the least expensive plants commanding more customers. Therefore, significant changes in the relative costs of producing energy from these fuels can change the electric generation mix profoundly.


regulatory and tax incentives for renewables, and increasingly stringent federal regulation of the byproducts of coal combustion.\(^4\) Of course, coal-fired electric generation emits significantly higher volumes of greenhouse gases and other air pollutants than natural gas-fired generation or renewables. Since coal combustion is associated with tens of thousands of premature deaths in the United States each year,\(^5\) the substitution of natural gas- for coal-fired generation could yield substantial health benefits.\(^6\) That is why some energy planners see natural gas as a "bridge fuel" in the process of moving from a fossil fuel economy to one fueled by renewable energy resources,\(^7\) and why American environmental regulators have long sought to reduce the environmental impacts of coal and coal-fired power. As described in the following sections, the U.S. Environmental Protection Agency (EPA) has initiated new or more stringent regulation of many aspects of coal combustion, including regulation of water usage, waste disposal, and emissions of coal-fired power under the Clean Air Act; the coal industry is also facing some increasingly stringent regulation of certain types of coal mining. This paper will explain the complicated regulatory structure that governs the extraction and combustion of coal to produce useful energy.

\(^4\) Edison Electric Institute estimates that recent and proposed EPA regulations addressing coal-fired power, cumulatively, would cause the unplanned retirement of 17 to 59 gigawatts (GW) of coal-fired electric capacity (5.4% to 18.8% of the current coal-fired total of about 315 GW) by 2015, and would require incremental capital expenditures of $85 billion to $129 billion. ICF International, Potential Impacts of Environmental Regulation on the U.S. Generation Fleet, Final Report, prepared for the Edison Electric Institute (January 2011), available at http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resources/2011IRP/EEIModelingReportFinal-28January2011.pdf. As noted below, the EPA's cost and impact estimates are much lower.


\(^6\) On the other hand, natural gas (methane) is itself a potent greenhouse gas. To the extent that natural gas production produces increases in fugitive emissions of natural gas from production facilities and pipelines, a move from coal- to natural gas-fired generation might not yield much in the way of greenhouse gas emissions benefits.

Coal Mining

Historically, American coal was initially found primarily in the Appalachian Mountains, particularly in Pennsylvania and West Virginia. Today, coal production in the Powder River Basin of Wyoming and Montana exceeds that of Appalachia. The shift in coal production from East to West has been accompanied by a decline in underground mining and a corresponding growth in surface mining. According to EPA estimates, coal mining accounts for about 15 percent of anthropogenic methane emissions in the United States. Coal mining also produces a broad range of other environmental externalities that have triggered a series of ongoing battles over the regulation of coal mining.

1. Health and Safety Regulation

Underground mining refers to the digging of shafts and tunnels spreading out underground from a single minehead. Underground mining creates highly intensive activity on the surface around the minehead, but does not necessarily produce substantial visual impacts on the surface of the land under which the coal lies, because most of the work takes place underground. There are a variety of different kinds of underground mining methods.

Underground coal mines pose significant health and safety problems for the mine workers, including the safety risks associated with the use of heavy equipment in confined

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8 According to the U.S. Energy Information Administration’s 2010 data, Powder River Basin production was 468,428 thousand short tons in 2010; Appalachian production was 335,248 short tons. U.S. Energy Information Administration, Annual Coal Report, 2011


10 These risks include: (1) methane gas, which is commonly found in association with coal, is potentially explosive and can also cause asphyxiation; (2) the risk that the mine will collapse, killing or injuring workers in the miners; and (3) coal dust inhalation risks, including, black lung disease, a progressive loss of lung capacity that can be fatal unless the miner retires promptly after the initial diagnosis Alan Derickson, Black Lung: Anatomy of a Public Health Disaster (Cornell University Press, 1998).
spaces, the risks of subsidence or collapse, and the risks of health hazards associated with
methane and coal dust in the air.\textsuperscript{11} These risks led to the passage of the Federal Coal Mine
Health and Safety Act of 1969 ("FCMHSA"),\textsuperscript{12} and the Black Lung Benefits Act of 1972.\textsuperscript{13} The
latter statute requires coal companies to contribute to healthcare benefit funds covering miners.\textsuperscript{14} These continuing obligations, coupled with an increased incidence of black lung disease among
miners during the last decade,\textsuperscript{15} means that health insurance obligations will remain a significant
component of mining costs into the foreseeable future.

For its part, the FCMHSA establishes health and safety standards for underground
mining. The statute regulates coal dust and methane concentrations in underground mines,
imposes detailed safety and health rules in mines, and delegates enforcement responsibility to the
Federal Mine Safety and Health Administration ("MSHA"). MSHA rules include equipment
standards,\textsuperscript{16} health standards,\textsuperscript{17} and safety standards.\textsuperscript{18} Mining operations must submit quarterly
reports of methane emissions, methane destruction (for example, through flaring), and carbon
dioxide emissions, where applicable.\textsuperscript{19}

\textsuperscript{11} Kirchgessner, et al. conclude that 74 percent of methane emissions from coal mining operations come from
underground mines.
\textsuperscript{12} 30 U.S.C. § 801 et seq.,
\textsuperscript{13} 30 U.S.C. § 900 et seq.
\textsuperscript{14} The Coal Industry Retiree Health Benefits Act of 1993 codified this obligation, which had been agreed to in
collective bargaining agreements between mining employers and mining unions. 26 U.S.C. §9601 et seq. The
retroactive application of the act was upheld in Usery v. Turner Elkhorn Mining Co., 428 U.S. 1 (1976).
\textsuperscript{15} Howard Berkes, As Mine Protections Fail, Black Lung Cases Surge, National Public Radio, July 9, 2012,
\textsuperscript{16} 30 CFR Parts 14-36.
\textsuperscript{17} 30 CFR Part 70 (focused mostly on airborne dust prevention and monitoring).
\textsuperscript{18} 30 CFR Part 75.
\textsuperscript{19} 40 CFR § 98.322.
2. Regulating Water Discharges from Mines

Another source of regulatory cost pressure on mining operations comes from Clean Water Act rules designed to prevent surface water pollution from mines. Both underground mining and surface mining commonly produce so-called gob piles or slag piles – huge piles of rock and earth at the surface. As rainwater hits these gob piles, the minerals leach acids and other contaminants into the runoff, producing something called "acid mine drainage" (or "AMD"), which can find its way into streams or other nearby surface waters. Because of these AMD discharges, mine owners must secure a Clean Water Act discharge permit; this permitting obligation may extend beyond the close of mine operations, if discharges continue to occur. Alternatively, because drainage from abandoned underground coal mines poses major water pollution problems in those areas where coal has been mined for many years, it can result in liability for current and former owners under the Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA").

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22 42 U.S.C. § 9601 et seq. CERCLA liability extends to current "owners or operators" of contaminated land, or owners or operators "at the time of disposal." 42 U.S.C. § 960. The question of when drainage constitutes "disposal" is a complicated one. See e.g., Carson Harbor Village, Ltd., v. Unocal, 240 F.3d 841 (9th Cir. 2001), cert. denied Carson Harbor Village, Ltd. v. Braley, 122 S. Ct. 1437 (2002) (concluding that passive migration did not constitute disposal). This CERCLA liability problem is often aggravated in the eastern United States because of the high sulfur content of the coal. See William H. Rodgers, Jr., Environmental Law 724 (West Publishing, 2d ed. 1994).
Under its Clean Water Act authority, the EPA has established effluent limitations\textsuperscript{23} and New Source Performance Standards governing AMD from mines, which specify the procedures mine owners should use to control discharges that contain acids.\textsuperscript{24} Generally, in order to comply with these standards, mine operators must use either active or passive treatment systems. An active system may be manual or mechanical and requires the periodic addition of reagents, ongoing support, and maintenance, such as adding lime to a treatment pool to raise the pH of an acidic discharge. Passive systems are designed to be self-sustaining and use chemical or biological processes that rely on no external support. For example, constructed wetlands are sometimes used to treat mine drainage because many of the plant species that comprise wetlands thrive on acidic material.

3. \textit{Surface Mining Reclamation}

As the name implies, surface mining involves the removal of surface vegetation and topsoil in order to expose coal seams, which are directly dug from the ground. Although surface mining lacks some of the health and safety risks associated with underground mining, it too is subject to MHSA rules.\textsuperscript{25} It also has a substantial impact on the surface landscape. In addition to the visual impacts associated with the removal of surface vegetation and soil (known as “overburden”), this process can entail some methane\textsuperscript{26} and other air emissions, as well as the discharge of pollutants to surface waters. Since 1977, the Federal Surface Mining Control and

\textsuperscript{23} 40 C.F.R. §§ 434.32-434.34.

\textsuperscript{24} 40 C.F.R. § 434.35. Generally, 40 CFR Part 434 addresses a variety of different water discharges from mines, including AMD.

\textsuperscript{25} See especially 30 CFT Parts 71 and 77, establishing health and safety rules for surface mines.

\textsuperscript{26} Kirchgessner, et al. conclude that 26 percent of methane emissions from coal mining operations come from surface mining, coal handling and abandoned mines.
Reclamation Act ("SMCRA")\textsuperscript{27} has imposed regulations on surface mining operations designed to mitigate damage to the land and to require reclamation of the land after mining activities are completed. Congress delegated the implementation of SMCRA to the Office of Surface Mining Reclamation and Enforcement ("OSMRE"), a bureau housed within the U.S. Department of Interior. OSMRE, in turn, has the authority to approve state enforcement plans, and to delegate enforcement of SMCRA to states with approved plans.\textsuperscript{28} SMCRA requires a permit before any person may engage in surface mining operations.\textsuperscript{29} The permit application requires the mine operators to plan the mining operation in detail, identify adverse effects on the environment, and devise a reclamation plan.\textsuperscript{30} OSMRE rules include requirements that mining permittees post a bond to ensure the availability of resources necessary for reclamation at the cessation of mining operations,\textsuperscript{31} as well as specific performance standards for different categories of surface coal mines.\textsuperscript{32} Approved state programs become incorporated into federal OSMRE requirements.\textsuperscript{33}

4. \textit{Surface Mining and Wetlands}

Another source of regulatory cost pressure on surface mining comes from the controversy (and recent regulatory change) over so-called "mountain-top mining." For surface mining operations in mountainous regions, the removal of overburden poses a storage and disposal

\begin{itemize}
  \item \textsuperscript{27} 30 U.S.C. § 1201 \textit{et seq.}
  \item \textsuperscript{28} 30 U.S.C. § 1253.
  \item \textsuperscript{29} 30 U.S.C. § 1256(a); and 30 CFR Parts 772 and 773 (OSMRE permit requirements for coal operations).
  \item \textsuperscript{30} 30 CFR Parts 773 and 780.
  \item \textsuperscript{31} 30 CFR Part 800.
  \item \textsuperscript{32} 30 CFR Parts 810-828. OSMRE enforces its own rules regarding acid mine drainage at surface mines. See Cheyenne Sales Co., Inc. v. Norton, 2007 WL 773904 (N.D. W.Va. 2007) (upholding the federal agency's assertion of jurisdiction).
  \item \textsuperscript{33} 30 CFR Parts 900-955. At times, there has been conflict between OSMRE and state agencies administering SMCRA. See e.g., National Mining Association v. U.S. Department of the Interior, 70F.2d 1345 (DC circuit 1995) (affirming the right of OSMRE issue a notice of violation directly to a mining company even though it had delegated to the state agency primary enforcement authority, and the state agency has declined to act).
\end{itemize}
problem. In its natural state, the overburden is compacted: when removed, the overburden expands in volume such that some of the overburden cannot be put back in place during the reclamation process; alternatively, there may be no place to store overburden during mining operations at steeply sloping sites. As a consequence, mining companies prefer to deposit the overburden in the valleys below. The deposit of this “fill” or "spoil" material into federal wetlands requires a permit under section 404 of the Clean Water Act. The U.S. Army Corps of Engineers exercises permitting jurisdiction under section 404, while the EPA exercises an oversight and consultative role in the wetlands permitting process.

In 2009 the Corps discontinued its long-standing practice of permitting the deposition of fill or spoil material from coal mining operations into valley wetlands – so-called "valley fill" activities – something it had permitted for many years under its "Nationwide Permit 21." Also in 2009, the EPA and the Army Corps of Engineers instituted a so-called "enhanced coordination procedure" through which the EPA concluded that most of the pending mountaintop mining projects in Appalachia posed a threat to water quality, resulting in delays in the processing of those projects’ Section 404 permit applications. In October 2011, a federal court struck down the "enhanced coordination procedure" as an improper encroachment by the EPA on the Corps’

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35 When it established the section 404 permitting program in 1972, Congress chose to vest primary permitting jurisdiction in the Corps, which already exercise jurisdiction over the deposit of fill material in harbors under the Rivers and Harbors Act of 1899.
36 These roles are specified in a series of memoranda of understanding between EPA and the Corps, available at the EPA web site, at http://water.epa.gov/lawsregs/guidance/wetlands/mining.cfm#background.
37 U.S. Army Corps of Engineers, Proposed Suspension and Modification of Nationwide Permit 21, 74 Fed. Reg. 3411 (July 15, 2009). Prior to 2009, Nationwide Permit 21 had included valley fill activities in its definition of "activities that result in no more than minimal impacts. The Corps reversed that position in 2009: consequently, valley fill activities now require an individual permit from the Corps.
permitting authority under the Clean Water Act.\textsuperscript{38} However, that decision did not alter the requirement that mining companies obtain individual section 404 permits for valley fill activities.

**Coal Combustion – Air Emissions**

According to the Energy Information Administration, there are approximately 1400 commercial coal-fired power plants currently operating in the United States.\textsuperscript{39} Coal combustion produces a variety of air pollution byproducts, including: (1) carbon dioxide (CO\textsubscript{2}), a greenhouse gas; (2) sulfur dioxide (SO\textsubscript{2}), a precursor of acid rain; (3) nitrogen oxides (NO\textsubscript{x}), precursors of both acid rain and ground-level ozone (smog); (4) fine particles (“particulate matter,” or “PM”), an inhalation hazard; and (5) mercury (Hg), ingestion of which poses a risk to neurological development.\textsuperscript{40} Coal combustion also uses enormous quantities of water and produces solid waste byproducts in the form of coal ash. Collectively, regulation of these risks may affect the cost competitiveness of coal-fired power, though there remains considerable dispute about the likely economic impact of these regulatory changes. Nevertheless, it seems apparent that coal-fired power plants are facing the prospect of increased regulatory compliance costs in the coming years.

1. **Clean Air Act Regulation, Generally**

The United States Congress passed the Clean Air Act of 1970 with coal-fired power plants in mind, noting specifically the effects of particulates, sulfur dioxide, and nitrogen oxides on human health.\textsuperscript{41} That statute placed all three pollutants on the list of conventional air


\textsuperscript{40} According to the EPA's 2009 National Emissions Inventory, the coal combustion accounts for about 50% of mercury emissions, and 60% of sulfur dioxide emissions in the United States.

\textsuperscript{41} See e.g., Section 109 of the Clean Air Act, 42 U.S.C. § 7409 (2000) (obligating EPA to establish NAAQS for sulfur dioxide and nitrogen oxides). 42 U.S.C. § 7409(a) requires NAAQS for all pollutants “for which air quality
pollutants for which EPA promulgates national ambient air quality standards ("NAAQS"). The Act requires new sources of pollution, like power plants, to secure a permit from state regulators before emitting conventional pollutants, like sulfur dioxide, particulates and nitrogen oxides into the air. The permit must contain emissions limitations for these pollutants that reflect the level of pollution control that is achievable given currently available technology, meaning that the emissions limits must be relatively more stringent than levels of pollution control achieved by most other similar sources. It is up to the states to determine the precise emissions limitation that reflects this technology-based standard at any given point in time, subject to the requirement that the limitation not be less than certain backstop levels established by EPA.

Thus, as new permits are issued and old permits expire and are renewed, and as pollution control technology grows more efficient and effective, the statutory technology-based standard—the level of pollution control that is available, achievable, and better than the industry norm—grows more stringent over time. Since the Act’s passage, more and more air quality control regions in
the United States have come into attainment\textsuperscript{47} with the NAAQS for particulates, ozone and sulfur dioxide,\textsuperscript{48} as ground level concentrations of these pollutants have declined steadily. Despite this progress, critics contend that coal combustion continues to do harm by emitting pollution that slips through the cracks of the Clean Air Act regulatory regime. One such regulatory gap has been the long term transport of sulfur dioxide (and to a lesser extent, nitrogen oxides) in the upper atmosphere; another has been the regulation of toxics. More recently, the emission of carbon dioxide and other greenhouse gases has been a concern. All of these issues are addressed separately below.

2. \textit{NAAQS Revisions}

The permitting standards that apply to emissions from sources of conventional pollutants depend upon whether the source is located in an attainment area or a non-attainment area for the pollutant in question. If the plant is located in an area that is in attainment with NAAQS for the pollutants in question, the permit must contain emissions limitations that reflect the applicable statutory technology-based standard: that is, "best available control technology" ("BACT").\textsuperscript{49} Alternatively, if the plant is located in a non-attainment area for the pollutants in question, its emissions limits must reflect the lowest achievable emissions rate" ("LAER").\textsuperscript{50} In addition, the EPA has established backstop emissions limits for emissions from many source categories in the form of New Source Performance Standards ("NSPS"), including a longstanding NSPS covering

\textsuperscript{47} 42 U.S.C. § 7407(d)(1)(A)(i) (2000). The Clean Air Act classifies all air quality control regions as either “attainment” or “non-attainment” areas for each conventional pollutant, depending upon whether the region is meeting the federal standard.

\textsuperscript{48} U.S. EPA, \textit{Nonattainment Areas Map - Criteria Air Pollutants}, at http://www.epa.gov/air/data/nonat.html?us~USA~United%20States (last modified Dec. 16, 2004) (stating that as of this writing, a mere 13 counties in the United States are “nonattainment” (i.e., out of compliance with) for the sulfur dioxide standard, while 57 counties (mostly in the west) are nonattainment for particulate matter and more than 400 counties are nonattainment for the ozone standard.). This represents considerable improvement since the 1970s and 80s, particularly with respect to sulfur dioxide and particulates.

\textsuperscript{49} 42 U.S.C. § 7475(a)(4).

\textsuperscript{50} 42 U.S.C. § 7503(a)(2).
emissions of conventional pollutants from coal-fired power plants. Though it was not always the case, a majority of large coal-fired power plants are now subject to the full panoply of Clean Air Act requirements applicable to conventional pollutants, because most are classified by the Act as "major sources" that have been modified since the Act’s passage.

The EPA has proposed important recent changes to its regulation of emissions of conventional pollutants, changes that could significantly increase the cost of coal-fired power production. Section 109 of the Clean Air Act directs the EPA to periodically review its NAAQS to ensure that they continue to protect public health. The EPA has initiated, completed, or is considering three important NAAQS revisions that may have important effects on coal-fired power plants. In 2010, EPA revised the NAAQS for SO2 and proposed revisions of the NAAQS for ozone. The new SO2 standard replaces the old 24-hour standard of 140 parts per billion (ppb) with a 1-hour maximum of 75 ppb, which may increase the number of SO2 nonattainment areas, triggering more stringent emissions limits in permits issued for facilities in

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51 See 40 CFR Part 60.
52 Coal-fired power plants generally trigger the Clean Air Act's major source size thresholds. See 42 U.S.C. §7602(j) (containing the statute's definition of "major stationary source") and §7612(a) (containing the statute's definition of "major source" of hazardous air pollutants). Since the Clean Air Act's emissions standards apply to new or modified sources, old coal-fired power plants that have not been "modified" since the Act’s passage were able to evade much of the Act’s coverage until the 1990s. Litigation and regulatory conflict ultimately subjected most of these old plants to the Act’s requirements and standards applicable to new sources. See Environmental Defense v. Duke Energy Corp., 549 U.S. 561(2007)(upholding a broader, EPA interpretation of the statutory term "modification").
53 Since the Clean Air Act's emissions standards apply to new or modified sources, old coal-fired power plants that have not been "modified" since the Act’s passage were able to evade much of the Act’s coverage until the 1990s. Litigation and regulatory conflict over the definition of "modification" ultimately resulted in regulatory changes, court orders and settlements that brought most of these old plants under the Act’s requirements applicable to new sources. See e.g., Environmental Defense v. Duke Energy Corp., 549 U.S. 561(2007)(upholding a broader, EPA interpretation of the statutory term "modification").
54 42 U.S.C. § 7409.
those new nonattainment areas. The proposed ozone standard revision would lower the primary (health-based) standard from its current level of 75 ppb to between 60 to 70 ppb, averaged over 8 hours. Finally, in January of 2013 the EPA is revised the current standard for annual emissions of fine particles downward to 12 micrograms per cubic meter57 (leaving unchanged the standards for coarse particles, or the daily standard for fine particles). As of this writing, the EPA is proceeding slowly and cautiously with respect to the ozone NAAQS revisions. It has withdrawn the proposed ozone standard revision in favor of further risk analyses and study.

3. Pollutant Transport Rules

In the 1980s, concern over the effects of acid rain prompted the creation of the “acid rain program” through amendments to the Act in 1990.58 The acid rain program imposed upon coal-fired power plants a graduated reduction of emissions of acid rain precursors of more than 50 percent. That program has remained in effect since its creation, and its emissions reductions have been achieved through a tradeable permit program under which plants may buy and sell sulfur dioxide and nitrogen oxides emissions rights.59

Efforts to address transport of nitrogen oxides – ozone precursors – have been more contentious. Interstate transport of pollution can cause violations of NAAQS in downwind states. The EPA’s CSAPR,60 the product of a long and litigious history of EPA attempts to

58 See, e.g., National Acid Precipitation Assessment Program, Report to Congress (1990) (finding that a debate among scientists and policymakers through the 1980s produced a scientific consensus supporting the notions that sulfur dioxide contributes to acid rain, and that acid rain acidifies lakes and damages vegetation).
59 42 U.S.C. §§ 7651-51o (2000) (outlining program in which acid rain allowances – each representing the right to emit one ton of sulfur dioxide in a calendar year – are bought and sold on several public commodities exchanges). For a description of the program, including a description of market activity in the allowance market, see U.S. EPA, Acid Rain Program, at http://www.epa.gov/airmarkets/arp/ (last modified Apr. 14, 2004).
address the interstate transport of pollutants, \(^{61}\) requires 27 states to reduce power plant emissions of sulfur dioxides and nitrogen oxides that contribute to ozone and/or fine particle pollution in other states. Reductions in sulfur dioxide emissions under the rule are particularly significant: emissions would decline to 73 percent below 2005 levels in the covered states in 2014. The EPA estimates that the rule will impose compliance costs on the power sector of about $2.4 billion annually once it is fully implemented, \(^{62}\) and will render about 4.8 GW of coal-fired electric generating capacity uneconomic. \(^{63}\) By virtue of these changes, the CSAPR would reduce emissions of CO2 from electrical generating units by about 25 million metric tons annually. \(^{64}\) In August 2012 the D.C. Circuit Court of Appeals struck down the rule, concluding that the rule violated the Clean Air Act by: (i) imposing emissions reductions obligations on upwind states beyond those authorized by the statute; and (ii) establishing a federal implementation plan for the rule, rather than allowing states to issue state plans. \(^{65}\) On June 24, 2013, the U.S. Supreme Court agreed to hear the appeal of the D.C. Circuit decision, and has not rendered a decision as of this writing, nor has the EPA taken any action in response to the D.C. Circuit decision.

\(^{61}\) In 1998 the Clinton EPA issued its "NOx SIP Call," a rule requiring 22 states in the eastern half of the country to further reduce their emissions of ozone precursors like nitrogen oxides, specifically mandating that electric generating units share a significant portion of the burden of those reductions. Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone, 63 Fed. Reg. 57356 (October 27, 1998). In 2005 the Bush EPA replaced the Clinton initiative with its own “Clean Air Interstate Rule” (“CAIR”), which imposed NOx emission limits (“budgets”) on 28 eastern states and the District of Columbia. 70 Fed. Reg. at 25,165 (March 25, 2005). In July 2008 the D.C. Circuit Court of Appeals overturned CAIR for, among other things, failing to properly address its stated purpose of reducing upwind contributions to NAAQS violations; however, in response to an EPA petition CAIR remained in effect until the EPA’s promulgation of CSAPR. North Carolina v. EPA, 531 F.3d 896, 907 (D.C. Cir. 2008).

\(^{62}\) EPA’s estimates the benefits of the rule, primarily in the form of tens of thousands of premature deaths avoided, to be significantly greater than this number.

\(^{63}\) 76 Fed. Reg. 48208, 48346.

\(^{64}\) 76 Fed. Reg. 48311.

4. Toxic Emissions

Coal-fired power plants can emit mercury and other pollutants classified as toxic (or as “hazardous air pollutants” or “HAPs”) under the Clean Air Act.66 New and existing major sources of toxic emissions must secure a permit covering those emissions, and the permit must reflect "maximum achievable control technology," or "MACT."67 In February 2012 the EPA finalized its MACT standard for the emissions of HAPs from coal-fired power plants.68 The rule follows conflict between environmental interests and the Clinton and Obama administrations, on the one hand, and industrial interests and the Bush administration, on the other, over whether to regulate mercury emissions from coal-fired power plants as a hazardous pollutant under the Clean Air Act.69 The EPA estimates annual compliance costs for this new rule in the electric power industry of about $9.6 billion, but concludes that the rule will have negligible overall impacts on jobs.70 The agency estimates that the benefits of the new rule will greatly exceed its costs, and that most of those benefits will consist of averted deaths, neurological disorders, diseases and environmental effects associated with coal-fired power emissions.71 This rule has provoked claims from industry and some states that it will interfere with electric utilities' ability

69 The Bush administration had reversed an earlier Clinton administration determination to regulate mercury emissions as a hazardous under section 112 of the Clean Air Act. The Bush administration proposed to regulate those emissions under section 111 of the Act, governing conventional pollutants. The Bush administration rule was overturned in in New Jersey v. EPA, 517 F.3d 574 (D.C. Cir. 2008), cert denied 129 S.Ct. 1308 (2009), which recounts the history of this dispute.
to provide reliable electric service in some states, as coal-fired power plants are taken off-line faster than they can be replaced. If so, the consequent reduction in coal-fired electricity production will result in a corresponding reduction in emissions.

5. *Greenhouse Gas Emissions from Coal Combustion*

The regulation of carbon dioxide emissions from coal-fired power plants is addressed by several recent EPA rules. First, coal-fired power plants must comply with the GHG reporting rule and the GHG tailoring rule, which impose a variety of new GHG emissions reporting and control obligations on plant owners. In addition, in April 2012 the EPA proposed a specific New Source Performance Standard ("NSPS") for carbon dioxide emissions from fossil fueled electric generating facilities. The proposed standard applies only to new facilities, and is based upon emissions performance of current natural gas combined cycle ("NGCC") units. Based upon current technology, in order for new coal-fired power plants to comply with the standard, the plants would need to employ carbon capture and storage technology, currently a very expensive proposition. Because the proposed standard does not require retrofitting or other action at existing coal-fired power plants, the EPA concluded that the proposed rule would impose no significant compliance costs. However, the Edison Electric Institute has estimated that the proposed standard would cost any new coal-fired power plants subject to its terms $25 per ton of carbon dioxide emitted from the facility, effectively preventing the construction of new coal-

72 See supra sections __ and __.


74 77 Fed. Reg. 22392, 22430 ("The EPA believes this proposed rule will have no notable compliance costs associated with it, because electric power companies would be expected to build new [electric generating units] that comply with the regulatory requirements of this proposal even in the absence of the proposal, due to existing and expected market conditions.").
fired plants. Perhaps in response to these concerns, the EPA has indicated that it plans to repropose the GHG NSPS for power plants. The EPA believes that current market conditions imply that electric power industry will not build new coal-fired or other electric generating facilities whose emissions will exceed the 2012 proposed standard in any event, and that NGCC units will likely be the predominant future fossil fuel-fired technology. If that prediction is borne out, coal fired power will continue to lose market share to natural gas-fired power and renewables, producing corresponding decreases in greenhouse gas emissions as a consequence. This trend may be hastened by the Obama Administration’s climate action plan, announced June 25, 2013, which directs the EPA to establish GHG emissions limits for existing power plants. As of this writing, no such limits have yet been proposed.

Other Byproducts of Coal Combustion

In addition to the myriad regulatory regimes covering the air emissions associated with coal combustion, the EPA also regulates water and land pollution from coal plants. In particular, it has recently proposed new restrictions on the use of cooling water at coal-fired power plants, as well as new restrictions on the disposal of coal ash from coal-fired power plants.

Coal-fired power plants have long been subject to effluent discharge permitting requirements under section 402 of the Clean Water Act. Recently, however, the EPA has proposed new requirements aimed at reducing fish entrainment at cooling water intake structures associated with new or existing power plants and industrial facilities. These new requirements,

75 ICF, supra note 000.
issued under the agency's authority under section 316 of the Act, specify that (i) existing facilities that withdraw at least 25 percent of their water from an adjacent waterbody exclusively for cooling purposes and (ii) have a design intake flow of greater than 2 million gallons per day, would be subject to an upper limit on how many fish can be killed by being pinned against intake screens (impingement). The EPA estimates that all steam electric generating facilities will trigger this provision. The rule also specifies that existing facilities that add electrical generation capacity would be required to add technology that is equivalent to closed-cycle cooling (which continually recycles and cools the water so that minimal water needs to be withdrawn from an adjacent waterbody). This implies a more than 90 percent reduction in intake flow rates compared to once-through cooling water systems, something EPA suggests can be accomplished by incorporating a closed-cycle system into the design of the new unit, or by making other design changes equivalent to the reductions associated with closed-cycle cooling. The EPA estimates that total annualized compliance costs for facilities covered by this rule to be $384 million, of which approximately $318 million will fall on steam electric generators. The EPA and industry disagree over the likely economic effects of these costs on electric generating units. The EPA projects compliance cost to average only a few hundredths of a cent per kilowatt hour of electricity generated.

Coal combustion also produces solid waste byproducts in the form of ash – specifically "fly ash," particles removed from flue gas by air pollution control devices, such as electrostatic

79 “Section 316(b) of the CWA provides that any standard established pursuant to section 301 … of the CWA and applicable to a point source must require that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available (BTA) for minimizing adverse environmental impact.” Id.

80 Alternatively, the facilities could reduce their intake velocity to 0.5 feet per second, because at that rate, most of the fish can swim away from the cooling water intake. 76 Fed. Reg. 22174. The proposed rule represents the EPA's response to litigation striking down portions of an earlier rule were all aimed at cooling water intake structures. That earlier rule was challenged by environmental groups and partly overturned by courts. See e.g., Riverkeeper, Inc. v. U.S. EPA, 358 F. 3d 174, 181 (2d Cir.2004); and Entergy Corp. v. Riverkeeper Inc., 129 S. Ct. 1498, 68 ERC 1001 (2009).


82 Specifically, the proposed rule would require reductions in the intake water flow to levels "commensurate" with the closed loop system. See 40 § 125.94(d)(proposed), 76 Fed. Reg. 22174, 22284.

precipitators or fabric filters, and "bottom ash," particles that are too heavy to become airborne and collect in the furnace of coal-fired power plant. Coal ash represents a high-volume waste stream, and coal ash is disposed of in a variety of ways, including placement in landfills or impoundments, and use in road aggregate and other products.\(^{84}\) Despite the fact that coal ash often contains heavy metals and other toxic constituents, coal ash is not a listed hazardous waste under the Resource Conservation and Recovery Act ("RCRA"),\(^{85}\) nor does it typically exhibit hazardous characteristics.\(^{86}\) Most states containing coal ash landfills and surface impoundments have established permitting regimes covering coal ash disposal, but some have not.\(^{87}\)

After a high-volume spill of coal ash from an impoundment into a river in Tennessee, the EPA proposed in 2010 to regulate the disposal of fly ash and bottom ash – known in the EPA proposed rule as "coal combustion residuals," or “CCRs” – in surface impoundments or landfills under RCRA. Specifically, the agency proposed two options: (1) a "subtitle C proposal," which would regulate impoundment and landfill disposal as a hazardous wastes under RCRA subtitle C; and (2) a "subtitle D proposal," under which would regulate these same wastes as nonhazardous solid waste under RCRA subtitle D.\(^{88}\) Specifically, the subtitle C proposal would

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85 42 U.S.C. § 6901 et seq. A 1980 amendment to RCRA (known as the “Bevill Amendment”) directed EPA to study the regulation of coal ash under RCRA. The EPA found in the May 2000 determination that “disposal of [coal ash] did not warrant regulation under RCRA subtitle C as a hazardous waste, but did warrant federal regulation as a solid waste under subtitle D of RCRA.” [CITE] Even though the EPA found that [coal ash] should be regulated under subtitle D of the Resource Conservation and Recovery Act (RCRA) in May 2000, the EPA never issued regulations under subtitle D.

86 Most coal ash passes the toxic characteristic leaching procedure test used to establish so-called "characteristic" hazardous wastes under RCRA.

87 This is according to a 2009 survey performed by the Association of Solid and Territorial Solid Waste Management Officials.

subject “CCRs from [new and existing] electric utilities and independent power producers when destined for disposal in a landfill or surface impoundment”\textsuperscript{89} to full regulation as a hazardous waste under RCRA, including the permitting requirements,\textsuperscript{90} cradle-to-grave waste management requirements,\textsuperscript{91} and disposal standards including post-closure care (including standards for dam safety for surface impoundments and for catastrophic releases).\textsuperscript{92} The less stringent subtitle D proposal would establish national criteria for the regulation of CCRs disposed of in surface impoundments or landfills, including location standards, composite liner requirements, groundwater monitoring and corrective action requirements, and closure and post-closure care requirements, among other things. As of this writing, the EPA has not issued a final rule on the disposal of coal combustion residuals.

**Conclusion**

The cumulative, simultaneous effect of these regulatory developments may make coal-fired power less competitive, thereby hastening the switch to natural gas and other fuels over the long run. They may render some existing coal-fired power plants unable to compete in electricity markets, and (along with the new GHG NSPS for power plants) offer additional disincentives – along with the low price of natural gas (and of natural gas futures) – to prospective builders of new coal-fired plants. However, they represent the latest stages in an long-running policy struggle to balance the need for cost-effective energy against the need to protect public health and the environment, a struggle that is likely to continue into the future.

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\textsuperscript{89} 75 Fed. Reg. 35128.

\textsuperscript{90} Those permitting rules are found that at 40 CFR parts 124 and 270.

\textsuperscript{91} Those requirements are found that 40 CFR parts 260 through 268, parts 270 to 279, and part 124.

\textsuperscript{92} 75 Fed. Reg. 35148-66.