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Regulation of Power Plant Wastewater Discharges: Summary of the EPA Final Rule

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Summary

To implement the Clean Water Act (CWA), the Environmental Protection Agency (EPA) issues effluent limitation guidelines (ELG), or technology-based standards, for categories of industrial dischargers. These standards are implemented through permits issued by states or EPA to individual facilities. In November 2015, EPA promulgated revised effluent limitations for the steam electric power industry to replace rules that were issued in 1982. The new rule was effective on January 4, 2016.

Two factors have altered existing wastestreams or created new wastestreams from many power plants since promulgation of the 1982 ELG. These factors are the development of new technologies for generating electric power, such as coal gasification, and, as a result of federal and state requirements, the widespread implementation of air pollution controls to reduce emissions of hazardous air pollutants and acid gases, such as flue gas desulfurization (scrubber) systems. While scrubbers dramatically reduce emissions of harmful pollutants into the air, some create a significant liquid waste stream. As a result, pollutant discharges from this industry to surface waters have increased in volume, with additional chemical constituents, and EPA believes that many current CWA permits for power plants do not fully address potential water quality impacts of these discharges.

Based on studies of the industry and to settle litigation brought by environmental advocates, EPA proposed a rule in April 2013 to revise the steam electric ELG and issued a final rule in November 2015. A total of 1,080 steam electric plants that burn fossil fuels and whose primary purpose is generating electricity are subject to the ELG. Only a subset of these plants is likely to incur compliance costs as a result of the 2015 rule—only 133—because a large portion of the industry has already implemented processes or technologies that are required by the rule. All of the plants that are expected to incur compliance costs are coal- or petroleum coke-fired. EPA estimates that the annualized compliance costs for the rule are $496 million pre-tax and $340 million after-tax, costs that the agency believes are economically achievable and would have minimal effects on the electricity market, both nationally and regionally. The rule also would reduce pollutant discharges by 385 million pounds annually and reduce water use by 57 billion gallons per year. Estimated costs of the rule exceed estimates of monetized benefits; however, the CWA does not require that the benefits of regulation exceed or even equal the costs.

An EPA rule under the Resource Conservation and Recovery Act (RCRA) on managing coal combustion residuals (CCR) also relates to the CWA ELG rule, because both statutes address coal ash that is generated by power plants and released to the environment. The scope of the CWA and RCRA rules differ. While both address disposal of CCR in surface impoundments at power plants, only the RCRA rule regulates disposal of CCRs in landfills. To coordinate the two rules, in the final CCR rule, EPA extended by one year that rule's deadline for owners or operators of covered facilities to prepare a closure plan. This would give owners or operators 24 months after publication of the CCR rule, or slightly more than 6 months after the effective date of the revised ELG, to understand the requirements of both regulations and to make the appropriate business decisions and prepare closure and post-closure plans.

Many in industry are concerned that the 2015 rule will impose new requirements and compliance timelines at the same time that power plants are implementing other EPA rules. One issue concerns impacts of the proposal on small entities, including small businesses and small governmental jurisdictions. Environmental advocates view the ELG differently from industry and reportedly are generally satisfied with the final rule, but many do have concerns with issues such as compliance deadlines in the rule. Both industry groups and environmental groups have challenged the rule in federal court.

EPA rules affecting steam electric power plants have been scrutinized and criticized based on their stringency, feasibility, and projected compliance costs. Congressional interest has been evident in legislation to alter the direction and substance of some of EPA's regulatory actions and initiatives. To this point, discussion of the power plant ELG has centered on the administrative proceedings at EPA and has not drawn specific attention of lawmakers.

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Introduction

Since 2009, the Environmental Protection Agency (EPA) has proposed, promulgated, and is developing a number of regulations affecting the operation of the nation's steam electric power plants. Given the central role of electric power in the nation's economy, concerns have been raised about the cost and potential impact of many of these regulations.

Industry and environmental advocacy groups have been keenly interested in both the substance of these rules and schedules for their implementation. A particular issue has been whether the regulations, especially the cumulative impact of implementing multiple rules, will lead to retirement of a significant number of electric generating units, with negative effects on the reliability of the nation's power supply. All together, these rules have been characterized by critics as a regulatory "train wreck" that would impose excessive costs and lead to plant retirements that could threaten the adequacy of electricity capacity across the country. EPA and many other analysts maintain that this will not be the case.

Much of the criticism addressed to EPA's actions has concerned Clean Air Act rules, but Clean Water Act (CWA) rules also have been part of the discussion, such as a 2014 rule to regulate cooling water intake structures at power plants and some industrial sources.[1] The most recent major rule affecting power plants that EPA has promulgated concerns limits on discharges of wastewater, and it is the subject of this report. It is the last of a suite of Obama Administration utility sector rules that also includes greenhouse gas standards for utilities and a rule for disposal of coal combustion residuals from power plants. The CWA power plant rule is a complex regulation, involving limits on six pollutant wastestreams. Finalized in November 2015, it updates standards that were issued more than 30 years ago, which did not reflect today's power plant technology.

Background

The 1972 CWA established a comprehensive program to "restore and maintain the chemical, physical and biological integrity of the Nation's waters." To implement the act, EPA was directed to issue effluent limitation guidelines and standards, or technology-based regulations, for industrial dischargers. The effluent limitation guidelines (ELG) are to reflect pollutant reductions that can be achieved by categories or subcategories of industrial point sources using technologies that represent appropriate levels of control. Since 1972, EPA has promulgated effluent limitation guidelines for 57 industrial categories, including for the steam electric power industry.

For point sources that introduce pollutants directly into U.S. waters (termed direct dischargers), limits on specific pollutants set in effluent guidelines are implemented through National Pollutant Discharge Elimination System (NPDES) permits that are issued by EPA or states. For sources that discharge to publicly owned treatment works, or POTWs (termed indirect dischargers), EPA promulgates pretreatment standards that apply to those sources and are enforced by POTWs, and state and federal authorities. The guidelines and standards apply to direct and indirect discharges of conventional pollutants;[2] toxic pollutants, including toxic metals and toxic organic pollutants;

[1] For information, see CRS Report R41786, *Cooling Water Intake Structures: Summary of the EPA Rule*, by (name re dacted) .

[2] CWA §304(a)(4) designates the following as conventional pollutants: biochemical oxygen demand (BOD5), total suspended solids, fecal coliform, pH, and any additional pollutants defined by EPA as conventional; EPA designated oil and grease as an additional conventional pollutant in 1979.

and non-conventional pollutants, which are all other pollutants that are not categorized as conventional or toxic (e.g., ammonia-N, phosphorus, and total dissolved solids).

The CWA established several different kinds of effluent limitations, four for new and existing direct dischargers and two for new and existing indirect dischargers. Effluent limitations are based on performance of specific technologies, but regulations do not require use of a specific control technology. In establishing effluent limitations, EPA considers the cost and/or economic achievability of the controls. The economic test differs based on the level of control specified in the ELG.

- Best Practicable Control Technology Currently Available (BPT)—BPT limitations generally are based on the average of the best existing performance of plants within the industry or subcategory. In specifying BPT, EPA considers the total cost of applying the control technology in relation to the effluent reduction benefits, as well as the age of the equipment and facilities, processes employed, and other factors. BPT limitations can cover conventional, toxic, and non-conventional pollutant discharges.
- Best Available Technology Economically Achievable (BAT)—BAT limitations generally represent the best existing performance in the industrial category or subcategory. BAT is the principal national means of controlling toxic and nonconventional pollutant discharges. Factors considered in assessing BAT include the cost of achieving BAT effluent reductions, processes employed, and other factors. The EPA Administrator has considerable discretion in assigning the weight accorded to these factors. BAT limitations may be based on effluent reductions attainable through changes in a facility's processes and operations.
- Best Conventional Pollutant Control Technology (BCT)—BCT is not an additional limitation, but it replaces BAT for the control of conventional pollutant discharges from existing industrial sources. The statute specifies factors to be assessed in determining BCT, including a two-part "cost reasonableness" test.
- New Source Performance Standards (NSPS)—NSPS are based on the best available demonstrated control technology (BADCT) and represent the most stringent control attainable through the application of technology. New plants have the opportunity to install the best and most efficient production processes and wastewater treatment technologies. EPA is directed to take into consideration the cost of achieving the effluent reduction and any non-water quality environmental impacts and energy requirements.
- Pretreatment Standards for Existing Sources (PSES)—PSES are designed to control the discharge of pollutants that pass through, interfere with, or are otherwise incompatible with the operation of a POTW. PSES standards are analogous to BAT for direct dischargers.
- Pretreatment Standards for New Sources (PSNS)—Like PSES, PSNS are designed to control the discharge of pollutants that pass through, interfere with, or are otherwise incompatible with the operation of a POTW. EPA considers the same factors in promulgating PSNS that it does in promulgating NSPS.

The requirements of the statute embody the concept that, over time, industrial sources will achieve greater pollutant removal by employing progressively more stringent technologies. Thus, the 1972 law required sources to achieve effluent limitations based on BPT by July 1, 1977, and effluent limitations based on BAT by July 1, 1983 (in 1987 Congress modified the BAT compliance date to March 31, 1989). New sources are expected to comply with applicable effluent limitations when they commence operation.

Requirements of ELGs apply to direct discharges through incorporation into NPDES permits issued by EPA or authorized states under CWA Section 402[3] and to indirect discharges through local pretreatment programs under CWA Section 307.[4]

Steam Electric Power Industry ELG

EPA initially promulgated effluent limitation guidelines for the steam electric industry in 1974 and issued revised standards in 1982.[5] The 1982 rules apply to about 1,100 nuclear- and fossil-fueled steam electric power plants nationwide, 495 of which are coal-fired.

Under CWA Section 301(d), EPA has a duty to review existing effluent limitation guidelines at least every five years and, if appropriate, revise them. EPA had been studying the ELG for the steam electric power generating category since the mid-1990s and on several occasions indicated that a preliminary study of discharges from this category was necessary. During the 2005 review of the existing effluent guidelines for all categories, EPA identified the rules governing the steam electric power point source category for possible revision, based in part on data showing that the industry ranked high in discharges of toxic and nonconventional pollutants. Power plant discharges account for about 30% of all toxic pollutants discharged into U.S. surface waters by all industrial categories that are regulated under the CWA.[6]

Broadly speaking, two factors have altered existing wastestreams or created new wastestreams at many power plants since promulgation of the 1982 power plant ELG. The first is the development of new technologies for generating electric power, such as coal gasification. The second, a result of federal and state requirements, is the widespread implementation of air pollution controls to reduce emissions of hazardous air pollutants and acid gases (e.g., flue gas desulfurization [FGD], selective catalytic reduction [SCR], and flue gas mercury controls [FGMC]). In particular, the use of wet FGD systems (the kind that generate liquid discharges) to control sulfur dioxide air emissions has increased significantly since 1982. Consequently, each year the pollutant discharges from this industry are increasing in volume, with additional chemical constituents. They account for 50%-60% of all toxic pollutants discharged into surface waters by all industrial categories currently regulated under the CWA, according to EPA. The main pollutants of concern for these discharges include metals (mercury, arsenic, selenium), nitrogen, and total dissolved solids (TDS).

EPA initiated a study, completed in 2009,[7] which found that the 1982 regulations did not adequately address the pollutants being discharged and have not kept pace with changes that have occurred in the electric power industry over the last three-plus decades, specifically the increase of FGD systems, or scrubbers, at coal-fired power plants to control air pollution. According to EPA, as of 2008, 30% of coal-fired power plants were using FGD systems to control sulfur

[3] 33 U.S.C. §1342. EPA has authorized 46 states to administer the NPDES permit program. See http://www.epa.gov/npdes/npdes-state-program-information.

[4] 33 U.S.C. §1317. EPA has authorized 36 states to administer pretreatment programs.

[5] 40 CFR Part 423.

[6] U.S. Environmental Protection Agency, Office of Water, *Final Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Industry*, Fact sheet, September 2015.

[7] U.S. Environmental Protection Agency, *Steam Electric Power Generating Point Source Category: Final Detailed Study Report*, EPA 821-R-09-008, October 2009.

dioxide emissions from the flue gas generated in the plants' boilers and prevent buildup of certain corrosive constituents such as chlorides, and by 2025, nearly 80% of coal-fired generating capacity is expected to employ FGD systems. While scrubbers dramatically reduce emissions of harmful pollutants into the air, some create a significant liquid waste stream (especially wet scrubbers). In addition, discharges from coal combustion residual (CCR) surface impoundments at steam electric power plants have a potential to degrade water quality. EPA believes that many current CWA permits for power plants do not fully address potential water quality impacts of these discharges through appropriate pollutant limits and monitoring and reporting requirements. In addition, EPA identified several wastestreams that are relatively new to the industry (e.g., carbon capture wastewater) and others for which there is little characterization data (e.g., gasification wastewater).

In 2009, environmental groups sued EPA to compel the agency to commit to a schedule for issuing revised guidelines for this industry. Pursuant to a 2010 consent decree that it entered into with these litigants, EPA agreed to propose the revised power plant ELG by July 23, 2012, and to finalize the rule by January 31, 2014. These dates were subsequently modified and required EPA to propose revised effluent limitations by April 2013, and publish a final rule 13 months later.[8] Pursuant to that agreement, EPA proposed revised standards on April 19, 2013. Public comments on the proposal were accepted until September 20, 2013. In April 2014, EPA and the environmental litigants agreed to give the agency an additional 16 months—until September 30, 2015—to finalize the effluent guidelines for the power plant sector. EPA announced the final rule on September 30, 2015; it was published in the *Federal Register* on November 3, 2015, and became effective on January 4, 2016.[9]

Overview of Sources Regulated under the Final Rule

The revised ELG applies to two broad categories of firms in the electric generating industry, electric utilities and non-industrial non-utilities. Both categories produce electric power for distribution and/or sale. Non-industrial non-utilities (which generally operate in a non-regulated pricing environment) account for 49% of plants but represent only 30% of total U.S. generating capacity. Utilities, which generally operate in a rate regulation framework, consist of investor owned utilities that account for about 50% of all U.S. electric generating capacity; publicly owned utilities (federal, state, and municipalities) that represent 13% of U.S. electric generation capacity; and rural electric cooperatives, representing 4% of U.S. generating capacity.

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[8] Consent decree in Defenders of Wildlife and Sierra Club v. EPA, Case No. 10-cv-1915, D.C. D.C., December 12, 2012. Electric utility industry groups, which were not parties to the consent decree, attempted to challenge the dates in the consent decree, but a federal appeals court ruled that the industry lacked standing to intervene in the consent decree that compelled EPA to follow a timeline for the rulemaking. Defenders of Wildlife v. EPA, D.C. Cir., No. 12-5122, April 23, 2013.

[9] U.S. Environmental Protection Agency, "Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, Final Rule," 80 *Federal Register* 67838-67903, November 3, 2015. EPA also issued several supporting documents in connection with the final rule. *Technical Development Document for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*, Document No. 821-R-15-007, September 2015, hereinafter, TDD; *Environmental Assessment for the Effluent Limitations Guidelines and Standards for the Steam Electric Generating Point Source Category*, Document No. 821-R-15-006, September 2015*; Benefit and Cost Analysis for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*, Document No. 821-R-15-005, September 2015, hereinafter, Benefit-Cost; and *Regulatory Impact Analysis for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*, Document No. 821-R-15-004, September 2015, hereinafter, RIA. See http://www.epa.gov/eg/steam-electric-power-generating-effluent-guidelines-2015-final-rule-documents.

The number of steam electric plants subject to the ELG is 1,080 (units that do not burn fossil fuels or plants with a primary purpose other than generating electricity are not subject to the ELG). These plants operate approximately 1,210 generating units with total capacity of 741,000 megawatts (MW) of electricity. According to data compiled by EPA for the rulemaking, the 1,080 steam electric plants represent about 19% of the total number of plants in the power generation sector, but represent about 70% of the total national electric generating capacity. The vast majority (93%) burn at least some amount of either coal or natural gas, and 74% of the steam electric units in the industry burn more than one type of fuel (e.g., coal and oil, coal and gas). Coal- and petroleum-coke fired plants comprise 44% of the 1,080 plants subject to the ELG. Coal is the most common primary fuel type for stand-alone steam turbines, while gas is the primary fuel for nearly all combined cycle systems. Oil-fired units account for about 5% of generating units, and nuclear plants account for about 4.5%.[10]

The largest capacity plants (>500 MW) comprise 63% of all steam electric power plants and 92% of the steam electric generating capacity for all plants regulated by the ELG. Most steam electric power plants are either gas- or coal-fired and have a generating capacity greater than 500 MW. The smallest plants, under 100 MW, comprise about 10% of plants and provide less than 1% of generating capacity, according to the industry data used in the rulemaking.[11]

Overview of the 1982 and 2015 Revised Rules

The 1982 pollutant discharge limitations apply to the following wastestreams: once-through cooling water, cooling tower blowdown, bottom ash transport water, fly ash transport water, boiler blowdown, metal cleaning wastes, low volume wastes,[12] and material storage and construction site runoff (including coal pile runoff). The 1982 ELG contains standards for BPT, BAT, and PSES for existing sources and NSPS and PSNS for new sources.

The 2013 proposal addressed BAT and PSES for existing sources, and NSPS and PSNS requirements for new sources.[13] EPA proposed to establish new or additional requirements for seven processes utilized by steam electric power plants and byproducts of those processes. EPA had found that these wastestreams, some of which were not evaluated or were evaluated to only a limited extent during the previous rulemakings, contain pollutants in concentrations and mass loadings that cause documented environmental impacts. EPA also determined that treatment technologies to reduce or eliminate the pollutant discharges are available, economically achievable, and have acceptable non-water quality environmental impacts.

In developing the 2013 proposal, EPA evaluated eight regulatory options[14] and ultimately identified four preferred alternatives out of the eight for regulation of existing discharges and one preferred alternative for regulation of new sources. In the proposed rule, EPA did not express a preference for any one of the four options for existing sources that discharge directly to surface water. The options differed in the wastestreams controlled by the regulation, the size of the units

[10] TDD, p. 4-17, Table 4-3.

[11] TDD, pp. 4-16–4-17, Table 4-4.

[12] Under the 1982 ELG, low volume wastes meant wastewater from all sources except those for which specific limitations are included, such as wastewater from boiler blowdown or floor drains.

[13] EPA did not propose to revise the 1982 BPT effluent guidelines, because the statutory deadline for compliance with BPT limits is long passed, and the same wastestreams would be controlled at the more stringent BAT and NSPS levels of the rule.

[14] The eight regulatory options are shown in 78 *Federal Register* 34458 (June 7, 2013), Table VII-1.

controlled, and the types of controls. Each of the options was successively more stringent in terms of pollutant removal, as well as more costly to implement.

The 2015 revised rule contains BAT and PSES standards for existing sources and NSPS and PSNS requirements for new sources, which apply to the following wastestreams: FGD wastewater, fly ash transport water, bottom ash transport water, flue gas mercury control (FGMC) system wastewater, gasification wastewater, and combustion residual leachate from landfills or surface impoundments. The requirements for these wastestreams are summarized in **Table 1** and are described below. (The six wastestreams are described in more detail in the **Appendix** to this report.)[15]

In developing the 2015 revised rule, EPA evaluated five regulatory options for existing sources—three were identical to options in the 2013 proposal, and two were variants of options in the proposed rule.[16] The BAT and PSES requirements for existing sources in the final rule are one of the variants. These requirements are most similar to the proposed rule's preferred option for new sources—and thus, most stringent—with the exception of one wastestream—combustion residual leachate. For that wastestream, the final rule establishes BAT standards equivalent to BPT requirements contained in the 1982 ELG.[17] For new sources (NSPS and PSNS), the final rule establishes standards at levels generally similar to the 2013 proposed rule. A new source is one that begins operation on November 17, 2015, or later.[18]

Table 1. Pollutant Discharge Limitations and Technology Basis for 2015 Steam Electric Generating Point Source Category Effluent Limitations Guidelines and Standards

Wastestreams	Pollutant Discharge Limitations and Technology Basis for Existing Sources (BAT and PSES)	Pollutant Discharge Limitations and Technology Basis for New Sources (NSPS and PSNS)
Flue Gas Desulfurization (FGD) Wastewater	Numeric limitations on mercury, arsenic, selenium, and nitrate/nitrite as N	Numeric limitations on mercury, arsenic, selenium, and Total Dissolved Solids (TDS)
	Chemical precipitation + biological control technology	Evaporation control technology
Fly Ash Transport Water	Zero discharge of pollutants	Zero discharge of pollutants
	Dry handling control technology	Dry handling control technology

[15] The 2013 proposed rule also included provisions to establish BAT/NSPS/PSES/PSNS standards for a seventh wastestream, non-chemical metal cleaning wastes, and to set those standards equal to BPT limits in the 1982 rules for chemical metal cleaning wastes. However, because EPA determined that it did not have sufficient information on discharges of non-chemical cleaning wastes or available control technologies, the 2015 revised rule reserves BAT/NSPS/PSES/PSNS for non-chemical metal cleaning wastes, as the previous regulations did. TDD, p. 8-37.

[16] EPA believes that none of the additional regulatory options considered for the final rule involves regulation of different pollutants or wastestreams, or the application of different control technologies, than those explicitly considered and presented in the proposed rule. 80 *Federal Register* 67848.

[17] A more stringent standard for combustion residual leachate that EPA considered but rejected would have required technology based on chemical precipitation, rather than surface impoundments, as in the final rule.

[18] Sources that were subject to the 1982 NSPS/PSNS will continue to be subject to such standards under the 2015 rule. In addition, sources to which the 1982 NSPS/PSNS apply are also subject to the newly promulgated BAT/PSES requirements of the 2015 rule, because they are existing sources with respect to requirements of the revised rule.

Wastestreams	Pollutant Discharge Limitations and Technology Basis for Existing Sources (BAT and PSES)	Pollutant Discharge Limitations and Technology Basis for New Sources (NSPS and PSNS)
Bottom Ash Transport Water	Zero discharge of pollutants	Zero discharge of pollutants
	Dry handling or closed loop control technology	Dry handling or closed loop control technology
Flue Gas Mercury Control (FGMC) Wastewater	Zero discharge of pollutants	Zero discharge of pollutants
	Dry handling control technology	Dry handling control technology
Gasification Wastewater	Numeric limitations on mercury, arsenic, selenium, and TDS	Numeric limitations on mercury, arsenic, selenium, and TDS
	Evaporation control technology	Evaporation control technology
Combustion Residual Leachate	Impoundment control technology (equal to BPT standard)	Numeric limitations on mercury and arsenic
		Chemical precipitation control technology

Source: TDD, Table 8-1, page 8-3, and U.S. Environmental Protection Agency, "Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category; Final Rule," 80 *Federal Register* 67838-67903, November 3, 2015.

Revised Requirements for Direct Discharges

For generating units that are *existing* sources and that discharge directly to surface waters, the final rule establishes BAT requirements as follows:

- For fly ash transport water, bottom ash transport water, and FGMC wastewater, the rule establishes a zero discharge limitation for all pollutants in these wastewaters. The BAT technology basis for fly ash transport water and FGMC wastewater is dry handling. The BAT technology basis for bottom ash transport water is dry handling or closed-loop systems.
- For FGD wastewater, the rule establishes numeric effluent limitations on mercury, arsenic, selenium, and nitrate/nitrite as N in the discharge. The numeric limits for these pollutants in the final rule are less stringent than the limits in the 2013 proposal.[19] The BAT technology for controlling this wastestream is based on chemical precipitation plus biological treatment.
- The final rule includes an option for existing dischargers of FGD wastewater that voluntarily choose to have extended time to achieve compliance with more stringent numeric limits for mercury, arsenic, selenium, and nitrate/nitrite as N. That is, rather than having to comply with the FGD standards as soon as possible after November 1, 2018 (see "Timing of New Requirements"), these sources will

[19] For example, under the 2013 proposal, direct discharges of FGD wastewater would have had to meet a limit of 242 nanograms per liter (ng/L) of mercury, maximum for any one day, and 119 ng/L for a 30-day average. The final rule establishes a limit of 788 ng/L for the same pollutant, maximum for any one day, and 356 ng/L for a 30-day average.

be required to comply with the more stringent standards, but not until December 31, 2023. The more stringent BAT limits under the voluntary option will require dischargers to use technology—chemical precipitation followed by evaporation—that EPA determined was too expensive to require for all steam electric power plants.[20]

- For gasification wastewater, the rule establishes numeric effluent limitations on mercury, arsenic, selenium, and Total Dissolved Solids (TDS) in the discharge. The BAT technology for controlling this wastestream is based on evaporation.
- The 1982 ELG included combustion residual leachate within the definition of low volume waste sources, which were subject to BPT limitations on TSS and oil and grease. In the final rule, EPA established a separate definition for combustion residual leachate; thus, no longer is it considered a low volume waste source. The BAT technology for managing combustion residual leachate in the revised rule is based on surface impoundments, the same as the 1982 BPT regulations.
- For all of the regulated wastestreams, the 2015 final rule retains BPT limits established in the 1982 rule for discharges of Total Suspended Solids (TSS) and oil and grease.

The final rule, like the 2013 proposed rule, establishes BAT effluent limits for existing oil-fired generating units and small electric generating units (EGUs), that is, those 50 MW or smaller, that differ from the effluent limits for all other generating units. For these facilities, EPA set BAT effluent limits equal to existing BPT effluent limits for all of the wastestreams addressed by the rule. According to EPA, oil-fired units generate substantially fewer pollutants, are generally older and operate less frequently, and in many cases are more susceptible to early retirement when faced with compliance costs attributable to the ELG. Likewise, small EGUs are more likely to incur compliance costs that are proportionately higher than those incurred by large units, because they are not as able to take advantage of economies of scale, while the amount of pollutants collectively discharged by small units is a small portion of pollutants discharged collectively by all power plants.

The final rule includes a provision to prevent existing facilities from circumventing the effluent limitation standards and guidelines. This anti-circumvention provision would prevent facilities from mixing wastewater from one of the more highly regulated waste streams with another that would be subject to a lower standard and disposing of the waste under the less stringent limit. The anti-circumvention provision applies only to those wastestreams for which the final rule establishes zero discharge limitations or standards (fly ash transport water, bottom ash transport water, and FGMC wastewater).

For all generating units that are *new* sources and will discharge directly to surface waters (including oil-fired and small generating units), the final rule establishes NSPS as follows:

- For fly ash transport water, bottom ash transport water, and FGMC wastewater, the rule establishes a zero discharge standard for all pollutants. The NSPS technology basis for fly ash transport water and FGMC wastewater is dry handling, and the technology basis for bottom ash transport water is dry handling

[20] The voluntary option in the final rule differs from a voluntary option under the proposed rule. The proposal included a voluntary incentives program with incentives in the form of additional implementation for plants that eliminate the discharge of all process wastewater (except cooling water). Because the final rule contains zero discharge limits for several wastestreams, EPA decided that the voluntary incentives program should focus on FGD wastewater. TDD, pp. 8-25–8-27.

or closed-loop systems. These are the same as the technology bases for the BAT limitations for direct discharges in the final rule.

- For discharges of FGD wastewater, the rule establishes numeric standards on mercury, arsenic, selenium, and TDS. The numeric limits for these pollutants are the same as the BAT limits for existing sources, described above. The NSPS technology is based on chemical precipitation followed by evaporation—the same basis as for BAT limitations for direct discharges in the voluntary incentives program described above.
- For discharges of gasification wastewater, the rule establishes numeric standards on arsenic, mercury, selenium, and TDS, which are the same as the BAT limits for existing sources, described above. Similarly, the NSPS technology is based on evaporation, the same basis as for BAT limitations for direct dischargers in the final rule.
- For discharges of combustion residual leachate, the rule establishes numeric standards on mercury and arsenic. The numeric limits for these pollutants are the same as the BAT limits for direct discharges from existing sources, described above. The NSPS technology basis of these requirements is chemical precipitation.

Revised Requirements for Indirect Discharges to Publicly Owned Treatment Works (POTWs)

As described above, EPA prescribes pretreatment standards for existing sources (PSES) and new sources (PSNS) that discharge wastewater to publicly owned treatment works (POTWs), rather than fully treating their wastes and discharging directly to nearby surface waters. Under CWA Section 307(b), pretreatment standards are intended to prevent the discharge of pollutants that would pass through, interfere with, or otherwise be incompatible with the operation of the POTW.

For discharges from *existing* sources to POTWs (PSES), the final rule establishes standards as follows:

- For fly ash transport water, bottom ash transport water, and FGMC wastewater, the 2015 rule establishes a zero discharge standard for all pollutants. The PSES technology basis of the standard for these wastestreams is dry handling (fly ash transport water and FGMC wastewater) and dry handling or closed-loop systems (bottom ash transport water).
- For discharges of FGD wastewater, the rule establishes numeric standards on mercury, arsenic, selenium, and nitrate/nitrite as N. The PSES technology basis for this wastestream is chemical precipitation plus biological treatment, the same as for BAT limitations for direct discharges in the final rule.
- For discharges of gasification wastewater, the rule establishes numeric standards on mercury, arsenic, selenium, and TDS. The PSES technology basis is evaporation.

For discharges from *new* sources to POTWs (PSNS), the 2015 revised rule establishes PSNS that are the same as the rule's NSPS, described above. EPA believes that the technology for new indirect discharging sources to meet these requirements is available and is economically achievable, because the costs to install technologies at new units are typically less than the costs to retrofit existing units. A key factor that affects compliance costs for *existing* sources is the need to retrofit new pollution controls to replace existing pollution controls, but new sources do not trigger retrofit costs because pollution controls are installed at the time the new source is constructed.

Relationship of the ELG to Other EPA Rules and Rulemakings

The steam electric power sector is a source of significant pollutant emissions and discharges to the environment,[21] and thus is subject to pollution control requirements under a number of federal environmental laws. In the preamble to the final rule and documents supporting it, EPA discusses how the ELG relates to several existing EPA rules and pending rulemakings. These include regulations under the Clean Air Act (such as Mercury and Air Toxics Standards promulgated in 2012 and the 2015 Clean Power Plan)[22] and other provisions of the CWA (such as the 2014 cooling water intake rule).[23] A 2014 rule under the Resource Conservation and Recovery Act (RCRA)[24] on managing coal combustion residuals (CCR) also relates to the CWA ELG rule, because both statutes address coal combustion waste such as coal ash that is generated by electric utilities and independent power producers and is released to the environment.

The ELG and the CCR Rule under RCRA

Disposal of CCR onsite at individual power plants may involve decades-long accumulation of tons of dry ash (in a landfill) or wet ash slurry (in a surface impoundment) deposited at the site. In December 2008, national attention was turned to risks associated with managing CCR when a breach in a surface impoundment pond at the Tennessee Valley Authority's Kingston, TN, plant released 1.1 billion gallons of coal fly ash slurry that damaged or destroyed homes and property. Beyond the potential for a sudden, catastrophic release from a surface impoundment, a more common threat associated with CCR management is the leaching of contaminants commonly present in the waste, primarily heavy metals, resulting in surface or groundwater contamination. This risk is particularly high at unlined surface impoundments, which are in common use today.

The Kingston release also brought attention to how the waste is managed and regulated. CCR management is primarily regulated by individual states. For several years, EPA considered whether and how to establish national standards to regulate CCR and address potential threats of improper CCR management to human health and the environment, because of concerns about inconsistencies and deficiencies in some state regulatory programs. In December 2014, EPA finalized a rule that establishes national criteria applicable to landfills and surface impoundments under RCRA's Subtitle D non-hazardous solid waste requirements.[25] The rule establishes

[21] EPA estimates that the total pollutant loadings associated with combustion wastewater discharges from steam electric power plants alone contribute 50%-60% of the reported toxic-weighted pollutant loadings of the combined discharges of all industrial categories currently regulated in the United States. 78 *Federal Register* 34505.

[22] For information, see CRS Report R42144, *EPA's Utility MACT: Will the Lights Go Out?*, by (name redacted) , and CRS Report R44341, *EPA's Clean Power Plan for Existing Power Plants: Frequently Asked Questions*, by (name redacted) et al.

[23] For information, see CRS Report R41786, *Cooling Water Intake Structures: Summary of the EPA Rule*, by (name re dacte d) .

[24] RCRA established the federal program for regulating solid and hazardous waste management (42 U.S.C. §§ 6901 et seq.). For information, see CRS Report RL30798, *Environmental Laws: Summaries of Major Statutes Administered by the Environmental Protection Agency*, coordinated by (name redacted) .

[25] U.S. Environmental Protection Agency, "Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals from Electric Utilities," 80 *Federal Register* 21302-21501, April 17, 2015. Although this rule was finalized by EPA in December 2014, it was not published in the *Federal Register* until April 2015. The effective date of the CCR rule is October 14, 2015.

technical requirements for CCR landfills and surface impoundments under Subtitle D of RCRA to address the risk of coal ash disposal. Under Subtitle D, EPA does not have the authority to implement or enforce its requirements. Instead, EPA will continue to rely on states to operate approved regulatory programs or citizen suits to enforce the new standards.

The scope of the CWA ELG and RCRA rule differ. While both address disposal of CCR in surface impoundments at power plants, only the RCRA rule regulates disposal of CCRs in landfills. In the preamble to the 2013 proposed ELG, EPA said that it would seek to effectively coordinate any final RCRA and CWA requirements to ensure that the rules work together while minimizing the potential for overlap of two regulatory structures, especially concerning surface impoundments. For example, the RCRA rule could potentially require a surface impoundment to either undergo closure or retrofit. But a decision on what action to take with that unit may ultimately be directly influenced by requirements of the revised ELG. One possible consequence of the requirements in the ELG is that many power plants will convert from wet to dry fly ash handling systems and will no longer send such wastes to surface impoundments. If this occurs, it might affect the time frames for closure of impoundments under a RCRA rule, according to EPA.

In the final CCR rule, EPA extended by one year, compared to the proposed rule, that rule's deadline for owners or operators of covered facilities to prepare a closure plan. This would give owners or operators 24 months after publication of the CCR rule, or slightly more than 6 months after the effective date of the revised ELG, to understand the requirements of both regulations and to make the appropriate business decisions and prepare closure and post-closure plans.[26]

BMPS for CCR Impoundments

CWA Section 304(e) authorizes EPA to supplement effluent limitation guidelines with Best Management Practices (BMPs) for toxic or hazardous pollutants in order to control plant site runoff, spillage or leaks, sludge or waste disposal, and drainage from raw material storage that is ancillary to the regulated industrial process and may contribute significant amounts of pollutants to U.S. waters. In the ELG proposal, EPA said that it was considering using this authority to establish BMP requirements to address impoundment construction, operation, and maintenance. EPA explained that the BMPs under consideration were similar to structural integrity and corrective action requirements that EPA had proposed in the then-pending RCRA rulemaking to address CCR.[27] In the CWA proposal, EPA said that the BMP provisions being considered in both the ELG and CCR rulemakings, such as requiring that impoundment inspections be conducted weekly by a qualified person, are critical to ensure that owners and operators of impoundments become aware of structural stability problems before they occur. If included in the ELG rule, these BMPs would become conditions to be included in CWA permits, along with numeric limits and other requirements in that rule, thus utilizing the CWA to accomplish a portion of the agency's objectives in the CCR regulatory proposal.

The 2013 CWA proposal included BMP provisions for CCR surface impoundments similar to those for coal slurry impoundments at coal mines promulgated by the Mine Safety and Health Administration (MSHA).[28] These provisions in the proposed ELG would require facilities using CCR impoundments to submit to the CWA permitting authority (EPA or an authorized state) plans for design, construction, and maintenance of existing impoundments, as well as closure plans.

[26] Ibid., p. 21428.

[27] The BMP provisions in the ELG proposal did not include closure requirements that were proposed as part of the CCR rulemaking under RCRA.

[28] 30 C.F.R. 77.216.

They also would require periodic inspection and annual certification of the construction, operation, and maintenance of the impoundment.

In the 2015 final CWA rule, EPA declined to include BMPs, saying that many commenters had argued that BMPs are better suited for the CCR rule.[29]

Timing of New Requirements

EPA believes that providing a window of time for facilities to raise capital, plan and design systems, and construct and test equipment will enable installation of technology during planned shutdown or maintenance periods. Further, EPA anticipates that for many plants, changes to FGD wastewater treatment systems, fly ash and bottom ash transport systems, and leachate treatment systems would constitute major system modifications requiring several years to accomplish. In the 2015 final rule, EPA provides that BAT limitations for existing sources (those that would establish requirements more stringent than existing BPT requirements) will apply beginning three years after the effective date of the rule. Thus, the rule will apply to discharges generated on or after the date established by the permitting authority that is as soon as possible within the next permitting cycle after November 1, 2018. Under the rule, all steam electric facilities will have the BAT limitations applied to their permits no later than December 31, 2023, approximately eight years from the anticipated date of promulgation of a final regulation. Permitting authorities will have flexibility to determine the "as soon as possible" date (but no later than December 31, 2023), based on considerations of a facility's need for new treatment technology. Plants are assumed to implement the control technologies beginning in 2019.

For those parts of the rule where EPA promulgated BAT limits equivalent to current BPT limits (e.g., combustion residual leachate), the rule does not build in an implementation period for meeting its limitations, since existing facilities presumably are already meeting these limits. These requirements are applicable on the date that a permit is issued to a discharger, after the rule's effective date. Also, new NSPS and PSNS requirements (for new sources) would be applicable on the effective date of the rule.

Because pretreatment standards are self-implementing (they do not require permits), existing sources that are indirect dischargers must comply with the final rule by November 1, 2018.

"Legacy" Wastewater

EPA defines "legacy" wastewater as discharges of wastewater and associated pollutants from existing sources from the six wastestreams regulated by the ELG that are generated prior to the date established by the permitting authority for the effective date of the 2015 rule (see above). Wastewater generated after the date established by the permitting authority is referred to as "newly generated" wastewater. Under the final rule (and as proposed by EPA in 2013), legacy wastewater discharges will continue to be subject to existing BPT effluent limits, not to more stringent BAT or PSES requirements that apply to newly generated wastewater. In other words, discharges from the regulated wastestreams that occur before the date set by the permitting authority for meeting the rule's new standards will not be required to retrofit to meet more stringent standards.

In developing the 2013 proposal, EPA found that these legacy wastewaters are typically transferred to surface impoundments that often commingle legacy wastewaters and other plant

[29] 80 *Federal Register* 67863.

wastewaters, such as cooling water or coal pile runoff. Except in limited circumstances, plants do not treat the legacy wastewater that they send to an impoundment using anything beyond the surface impoundment itself. Under the 2015 final rule, the technology basis to meet the rule's BAT requirements will eliminate wastewater in the future (e.g., the zero discharge requirement for fly ash transport water will necessitate conversion to dry ash handling) but does not eliminate wastewater that has already been generated and transferred to an existing impoundment. EPA evaluated whether technologies would be available that might represent BAT for these legacy wastewaters, but determined that these alternatives are either impracticable or insufficient data are available for establishing BAT effluent limitations. In the final rule, the agency did not establish zero discharge BAT limitations for legacy wastewater because technologies that can achieve zero discharge were not shown to be available. EPA believes that the rule's zero discharge requirements for newly generated discharges of fly ash transport water, bottom ash transport water, and FGMC wastewater will provide strong incentives for power plants to greatly reduce, if not completely eliminate, disposal of their major sources of ash-containing wastewater in surface impoundments.[30]

Costs and Benefits of the ELG

Compliance Costs

EPA estimates that the final rule will result in annualized pre-tax compliance costs for industry of $496.2 million and after-tax costs of $339.6 million.[31] Pre-tax costs provide insight on the total expenditures as incurred by the plants, while after-tax annualized costs are a more meaningful measure of impact on privately owned for-profit plants, because they incorporate approximate capital depreciation and other relevant tax treatments in the analysis.[32] EPA's estimates of compliance costs reflect anticipated unit retirements or fuel conversion, ash handling conversions (from wet to a dry or closed-loop ash handling system), and repowerings[33] announced as of August 2015. The agency projects that 133 steam electric power plants (130 direct discharging facilities and three indirect discharging plants), or 12% of plants to which the final rule applies, will incur costs associated with the rule.[34]

EPA also analyzed the social costs of the final ELG, which are the costs from the viewpoint of society as a whole, rather than regulated facilities only. Social costs include costs incurred by both private entities and government in implementing the regulation. In this case, EPA estimates that the final rule will not lead to additional costs to permitting authorities, so, in calculating social costs, the agency only estimated social costs for owners of steam electric power plants. The analysis projects total annualized social costs of $479.5 million at a 3% discount rate and $471.2 million at a 7% discount rate. The value for the 7% discount rate is slightly lower than the comparable pre-tax industry costs described above ($471.2 million versus $496.2 million) due to the consideration of the timing of expenditures in the annualized social calculations.[35]

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[30] Ibid., pp. 67854-67855.

[31] 2013 dollars at a 7% discount rate.

[32] 80 *Federal Register* 67864.

[33] Repowering is the process of replacing older power stations with newer ones that either have a greater nameplate capacity or more efficiency which results in a net increase of power generated.

[34] 80 *Federal Register* 67881.

[35] Ibid., pp. 67864-67865. The social cost analysis covers a 24-year period during which plants install control (continued...)

Overall, EPA concludes that the limitations and standards in the final rule are economically achievable for the industry as a whole. EPA projects that 88% of the plants subject to the rule will incur zero compliance costs, because they already have implemented processes or technologies that are the basis for the rule. An estimated 8% of plants will incur compliance costs of less than 1% of revenue and in EPA's view are unlikely to face economic impacts (88 plants) as a result of the ELG rule. The agency estimates that 4% of plants will have compliance costs between 1% and 3% of revenue (38 plants), and less than 1% of plants have costs above 3% of revenue (eight plants).

The number of plants projected to incur non-zero compliance costs is about 50% less than that estimated at the time of the 2013 proposal, due to such factors as announced unit retirements, relevant operational changes, and changes that plants are likely to make in response to the CCR and other EPA rules.[36] Regionally, plants in the Reliability First Corporation (covering the eastern United States and lower Great Lakes region) and the Southeast are generally expected to have the highest compliance costs.

EPA estimates that variable production costs at steam electric power plants will increase by approximately 0.3%, or 10 cents per megawatt-hour, at the national level as a result of the rule. Major compliance costs are associated with controls on FGD and bottom ash transport wastewater. An important factor that reduced total compliance costs of the final rule, compared with stringent alternatives in the 2013 proposal, is the standard for one of the wastestreams, combustion residual leachate. By retaining the technology basis of the 1982 BPT ELG—i.e., surface impoundments—EPA concluded that facilities will incur no compliance costs for managing this wastestream. In developing the final rule, the agency considered a regulatory option that would establish limitations for arsenic and mercury in combustion residual leachate based on treatment using a chemical precipitation system, but concluded that the amount of pollutants discharged in combustion residual leachate is a small portion of the pollutants discharged collectively by all steam electric power plants. That fact, combined with the final rule's standards for larger contributors of pollutant discharges (e.g., FGD wastewater), led EPA to conclude that retaining the BPT standard for this wastestream still represents reasonable further progress toward the CWA's goal of eliminating the discharge of all pollutants.[37]

EPA does not expect the final rule to increase costs to permitting authorities, because it does not change permit application requirements or increase the number of permits issued to steam electric power plants. Overall, EPA expects that the rule will reduce the burden to permitting authorities, because, by establishing national BAT standards, it will require permitting authorities to make fewer site-specific permitting decisions than under the 1982 ELG.[38]

Electricity Market and Other Impacts

EPA also examined impacts of the final rule on electricity markets, including changes in capacity to plant or unit closures (i.e., capacity closures and avoided closures) and changes in the price of electricity (due to increased generation costs). Overall, EPA concluded that the final rule will not significantly affect total costs of electricity production either in the short run (2020) or the long

(...continued)

technologies and the useful life of the longest-lived technology at any facility (20 years).

[36] Ibid., p. 67864.

[37] Ibid., p. 67854.

[38] Ibid., p. 67888.

run (2030). Under the final rule, the electricity market would generate 843 million kWh less coal-fired electricity in 2030, or 0.2% of the 359,982 MW baseline (2009) capacity. The change is based on a combination of incremental capacity closures (corresponding to eight generating units nationwide) and avoided capacity closures nationally (six generating units).

EPA projects that the final rule will have small effects on the electricity market in 2030, both nationally and regionally, despite the higher compliance costs. At the national level, total annual costs are estimated to increase by 0.4%, compared with the 2009 baseline. The agency's model projects a small increase on electricity prices nationally, with increases of no more than 0.5% in any region and a 0.2% reduction in the West.

EPA examined impacts of the ELG on residential, commercial, industrial, and transportation consumers and concluded that industrial consumers would experience the highest price increases relative to their baseline electricity price (0.21% nationally), while residential consumers would experience the lowest price increases (0.11% nationally). The higher relative price increase for industrial consumers is due to the lower baseline electricity rates paid by this sector and EPA's assumption of uniform price increase across all consumer groups. EPA's analysis shows the average annual cost per residential household increasing as a result of the ELG, depending on the region, by $0.03 (in the Northeast Power Coordinating Council region) to $2.67 (in the Reliability First Corporation region) with a national average of $1.42.[39]

EPA's model projects that total coal-fired generating capacity will decrease by approximately 0.6% due to the ELG final rule. Coal-fired plants may generate less electricity than would otherwise occur in the absence of the rule, due to increased production costs. In addition, some plants may retire earlier than would otherwise occur. These effects may lead to lower employment at coal-fired power plants and in coal mining. Generation using other fuels, including natural gas, nuclear power, and renewable fuels such as biomass, would increase modestly and would have positive labor impacts (e.g., natural gas extraction, constructing and operating natural gas power plants). EPA estimated that approximately 60% of the annualized compliance costs for the final rule are annualized capital costs. These capital costs are not expected to significantly affect employment at steam electric power plants themselves, but could increase employment in industries that manufacture and install equipment, according to EPA.[40]

Many stakeholders and other observers have criticized EPA for not analyzing the impacts of its regulatory proposals on jobs, the labor market, and the economy broadly, arguing that the agency fails to consider the economy-wide effects of its rules. EPA does not have a robust methodology to fully assess impact of all possible changes in employment, so it is difficult for the agency to project how the ELG would affect employment levels in the entire U.S. economy. Thus, EPA did not quantify long-run economy-wide regulatory changes in employment resulting from the ELG, which would depend on how the electric power sector adjusts to regulatory requirements, as well as indirect upstream and downstream effects in the rest of the economy, and the overall state of the economy and the labor market.[41]

EPA acknowledges some uncertainties in these analyses. For example, it assumes that electricity demand at the national level would not change between the baseline and post-compliance options, and the model does not capture changes in demand that may result from electricity price increases associated with proposed ELG. Also, fuel prices—differences in actual fuel prices vs. modeled

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[39] RIA, pp. 7-4–7-9.

[40] Ibid., pp. 6-5–6-12.

[41] Ibid.

prices, such as lower natural gas prices—would be expected to affect the cost of electricity generation and the amount of electricity generated, but effects of fuel prices are not reflected in the analysis. Estimates of price increases to households and other consumer groups assume 100% pass-through of compliance costs, which EPA characterizes as a worse-case scenario that may overstate potential impact, depending on whether power plants are able to pass their costs on to electricity customers. Further, how states choose to comply with the Clean Power Plan may lead to fewer or more coal-fired steam power plant retirements than EPA's model is able to project. Such differences could affect power plant existing and new capacity, production costs, prices, and other factors.

Environmental Benefits/Pollutant Reductions Compared with Costs

EPA estimated the reduction of conventional, non-conventional, and priority (toxic) pollutants that would result from the final rule is 385 million pounds per year. The largest amount of pollutant reduction (96%) is nonconventional pollutants, such as ammonia, phosphorus, and TDS. Additionally, the final rule will eliminate or reduce water withdrawals associated with wet fly ash and bottom ash transport and wet FGD scrubbers by 57 billion gallons per year. Reduced water usage is significant, because total water withdrawals by the steam electric power industry (primarily for cooling purposes) are larger than those of any other public or private sector.[42]

EPA expects a number of environmental and ecological improvements and reduced impacts to wildlife and human health to result from reductions in effluent loadings for the different proposed options. The agency conducted an environmental assessment that examined several beneficial outcomes, including improvements in water quality, reduction in impacts to wildlife, and reduction in number of receiving waters impacted by potential human health cancer and non-cancer risks.

In that analysis, EPA estimated that reduced pollutant loadings to surface waters would improve water quality by reducing metal concentrations to receiving waters. Metals in combustion wastewater discharges such as arsenic, cadmium, copper, and chromium can drastically alter aquatic populations and communities and the surrounding ecosystems that rely on them. Selenium is the metal most frequently associated with environmental impacts following exposure to combustion wastewaters. On average, total selenium receiving water concentrations would be reduced by two-thirds under the final rule, leading to a reduction in the number of receiving waters exceeding the freshwater chronic criteria for selenium.[43]

EPA acknowledges that there are varying degrees of completeness and rigor in its ability to assess benefits. Where possible, EPA quantified expected effects and associated human health and ecological benefits—such as reduced incidence of cancer from arsenic exposure via fish consumption—but EPA was able to monetize only a small subset of health benefits associated with reduced steam electric discharges. Other benefits can be quantified, but not monetized, such as reduced non-cancer adverse health effects. Quantifying and monetizing the benefits of regulations is challenging because of a large number of uncertainties in approaches used to value benefits. Finally, due to data limitations and gaps in understanding how society values certain

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[42] Water withdrawals for thermoelectric power were 161 billion gallons in 2010, or 45% of total withdrawals for all uses. U.S. Geological Survey, U.S. Department of the Interior, *Estimated Use of Water in the United States in 2010*, Circular 1405, 2014.

[43] 80 *Federal Register* 67874.

water quality changes, some effects can be neither quantified nor monetized, such as reduced sediment contamination and increased property values from water quality improvements.

EPA also recognizes a number of other limitations and uncertainties in analyzing benefits. Some may lead to potential overestimation of benefits. For example, the analysis is based on information on loadings of toxic metals that that was subsequently revised downward by EPA, and the change indicates that water quality improvements due to the ELG may be lower than the agency estimated. Others may lead to underestimation of benefits: EPA estimated the benefits of reducing mercury exposure in children, but not in adults, although the scientific literature suggests that exposure to mercury also may have adverse health effects in adults.[44]

Despite the data limitations, EPA projects annualized monetized benefits of the final rule (human health, recreational uses, improved ecological conditions, groundwater quality, avoided impoundment failures, air-related [i.e., human health and avoided climate change impacts], and reduced water withdrawals) to range from $451 million to $566 million, with a mid-point of $463 million (at a 3% discount rate), and from $387 million to $478 million, with a mid-point of $397 million, at a 7% discount rate.[45]

Finally, EPA evaluated the net benefits (i.e., benefits minus costs) and estimates that the annual monetized social costs exceed the mid-range annual monetized benefits for the final ELG by $16.5 million using a 3% discount rate and by $74.2 million using a 7% discount rate.[46] It should be noted that the CWA does not require that the benefits of regulation exceed or even equal the costs. It does require that effluent limitations "result in reasonable further progress toward the national goal of eliminating the discharge of all pollutants."[47]

Issues

Steam electric power plants are highly technical and complex industrial operations. So, too, the revised ELG is very technical and complex. Industry's major concern with the 2013 proposed rule was that EPA would set overly stringent standards that will be an economic burden on generators and may not be achievable. Following release of the final rule, an industry spokesman noted that the rule will force technological and operational changes at existing facilities that have the potential to create compliance challenges and increase customer costs.[48] The technology bases of the rule are available, companies generally agree, but there is concern that the standards may require extensive retrofitting that is costly and could reduce generating plant effectiveness, and some may be infeasible (e.g., may not be physically possible within the plant's footprint). Many in industry are concerned that the CWA rule imposes new requirements and compliance timelines at the same time that power plants are implementing other costly and burdensome EPA rules. The

[44] Benefit-Cost, pp. 3-21–3-23, 4-22–4-23.

[45] EPA estimated the annualized value of future benefits using two discount rates: 3% and 7%. The 3% discount rate reflects society's valuation of differences in the timing of consumption; the 7% discount rate reflects the opportunity cost of capital to society. In Circular A-4, the Office of Management and Budget recommends that 3% be used when a regulation affects private consumption, and 7% be used in evaluating a regulation that will mainly displace or alter the use of capital in the private sector. All future costs and benefits in EPA's analyses are discounted to 2015, the promulgation year of the rule, and are expressed in 2013 dollars.

[46] Benefit-Cost, pp. 13-2–13-3.

[47] CWA §301(b)((2)(A); 33 U.S.C 1311(b)(2)(a).

[48] Lara Beaven, "Advocates Mull Challenge to 'Suspect' Utility ELG Legacy Waste Provisions," *InsideEPA*, October 15, 2015. Hereinafter, Beaven, *InsideEPA*.

agency attempted to address the issue of timing and coordination with other rules both through the timing of the final ELG and deadlines in the RCRA coal ash rule, discussed above.

One issue concerns impacts of the rule on small entities, including small businesses and small governmental jurisdictions. The Regulatory Flexibility Act (RFA) requires agencies to prepare a regulatory flexibility analysis of most rules. The RFA, as amended by the Small Business Regulatory Enforcement Fairness Act (SBREFA), requires EPA to convene a Small Business Advocacy Review Panel for most rules, unless the agency can certify that a rule will not have a significant economic impact on a substantial number of small entities.[49]

EPA did analyze impacts of the proposed ELG on small entities. EPA projects that 22 small entities (small businesses, small organizations, and small governmental jurisdictions) will incur compliance costs as a result of the final rule. It estimates that six small entities owning steam electric power plants (one cooperative, one nonutility, and four municipalities) will incur compliance costs exceeding 1% of revenue as a result of the final rule, and one additional municipality will incur costs exceeding 3% of revenue. Further, potential impacts of the rule on small entities and municipalities are reduced by establishing requirements for small power plants (50 MW or less) equal to the previous BPT limits. The agency believes that these impacts are small and support a finding of no significant economic impact on a substantial number of small entities.[50]

Nevertheless, a number of stakeholders are concerned that EPA underestimated costs of portions of the rule (for example, by overestimating the bottom ash removal efficiencies of power plants). Some were critical that EPA did not convene a SBREFA panel, with small business representatives participating, to evaluate the impact prior to the proposed rulemaking.[51] Spokesmen for the National Rural Electric Cooperative Association (NRECA) argue that EPA has underestimated compliance costs of the final rule. NRECA believes that the ELG, together with other recent EPA rules, will disproportionately affect the small- and medium-sized power plants that its members operate.[52]

Environmental advocates view the ELG differently from industry and reportedly are generally satisfied with the final rule, but expressed concerns that parts of the rule were not stringent enough. Many had urged that EPA promulgate standards requiring the most environmentally protective technologies (i.e., dry handling of fly ash and bottom ash by all plants, and chemical precipitation plus biological treatment or evaporation of FGD scrubber waste by all plants). They opposed regulatory options in the proposed rule would have set BAT equal to current BPT standards for some wastestreams and thus allow continued use of surface impoundments for bottom ash and combustion residual leachate, because impoundments can be a significant source of contamination of surface and ground water. Thus, they endorsed provisions of the final rule that will require dry handling of fly ash and bottom ash from power plants.

Environmental advocates indicated concern with some provisions of the final rule, however, such as allowing compliance deadlines as late as December 31, 2023, under the rule's incentive program (rather than in three years) and the lack of strict limits on legacy wastestreams, discussed previously. Some advocates dispute EPA's view that it is not possible to establish BAT limits for

[49] 5 U.S.C. §§601 et seq.

[50] 80 *Federal Register* 67888-67889.

[51] In June 2011, EPA issued a notice inviting small businesses to nominate representatives to participate in a SBREFA panel in connection with the rule. However, no panel was convened.

[52] Amena H. Saiyid, "New Power Plant Effluent Limits Too Costly, Critics Say," *Bloomberg BNA Daily Environment Report*, November 3, 2015, pp. B-1.

power plant wastestreams that are generated before standards under the new rule are required and believe that the rule should have addressed waste that leaks from old, inactive coal ash ponds.[53]

Conclusion

As noted in the introduction to this report, EPA rules affecting steam electric power plants have been scrutinized and challenged based on their stringency, feasibility, and projected compliance costs. Some argue that these rules may change the economics of power production, the fuel profile of the electricity market, and electricity rates. Congressional interest has been evident in legislation that has been introduced to alter the direction and substance of some of EPA's regulatory actions and initiatives. To this point, discussion of the power plant ELG has centered on the administrative proceedings at EPA and has not drawn significant attention of lawmakers.

Following promulgation of the ELG, attention has shifted to the federal courts. Petitions for review of the ELG were filed in several federal courts of appeals and have been consolidated in the U.S. Court of Appeals for the Fifth Circuit (*Southwestern Elec. Power Co. v. EPA*, 5th Cir., 15-60821, filed November 20, 2015). The consolidated cases include challenges filed by individual electric utility companies and a group of such companies, as well as environmental advocacy groups. The deadline for new challenges to the ELG is March 16, 2016, under a 120-day time limit that started two weeks after the rule's publication in the *Federal Register*.

[53] Beaven, *InsideEPA*.

Appendix. Steam Electric Power Plant Wastestreams Regulated under the 2015 Revised ELG

This Appendix provides additional detail on the six wastestreams from steam electric power plants that are regulated in the revised ELG.[54] Also see the summary information in **Table 1**.

FGD Wastewater

FGD systems remove sulfur dioxide from the flue gas so that it is not emitted into the air. There are approximately 401 FGD systems either currently operating or planned in the United States. Approximately 17% are dry systems that do not generate wastewater and are not subject to the FGD wastewater requirements of the ELG, while the remaining 83% are wet FGD systems that generate a slurry and are subject to FGD requirements of the rule. Dry FGD systems typically remove 80% to 90% of the sulfur dioxide, which is less than a wet FGD system which in some cases can remove up to 99%. In wet FGD systems, the flue gas stream comes in contact with a liquid stream containing a sorbent, which is used to effect the transfer of pollutants from the flue gas to the liquid stream. Of the 150 plants with wet FGD systems, 100 discharge FGD wastewater after treatment using one or more of several technologies alone or in combination, including surface impoundments, chemical precipitation systems, biological treatment, vapor-compression evaporation systems, and constructed wetlands. EPA estimates that the steam electric industry discharges 16.1 billion gallons of FGD wastewater per year, with an average total industry daily discharge of 0.45 million gallons per day (MGD) per plant. Wastewaters generated by wet FGD systems generally contain significant levels of metals and other pollutants of concern. EPA found that treatment technologies are available to treat these pollutants in FGD wastewater; however, most plants use only surface impoundments that are designed primarily to remove suspended solids from FGD wastewater via settling.

Historically, power plants relied on surface impoundments to treat FGD wastewater because NPDES permits generally focused on controlling suspended solids for this wastestream. Metals in FGD wastewater are present both in particulate form, which can be substantially removed by settling (e.g., arsenic), and in soluble (i.e., dissolved) form (metals such as selenium, boron, and magnesium) that is not effectively and reliably removed by surface impoundments. More advanced technologies are available that are effective at removing both soluble and dissolved forms of metals, as well as nitrogen and total dissolved solids (TDS). The technology basis for the final rule is chemical precipitation/coprecipitation used in combination with anoxic/anaerobic biological treatment to optimize removal of selenium. EPA determined that 45% of all steam electric power plants with wet scrubbers have equipment or processes in place able to meet the final BAT/PSES effluent limitations and standards in the 2015 rule. Many of these plants use FGD wastewater management approaches that eliminate the discharge of FGD wastewater. EPA rejected technology based on chemical precipitation alone for FGD wastewater because, while chemical treatment systems are capable of achieving removals of various metals, the technology is not effective at removing selenium, nitrogen compounds, and certain metals that contribute to high concentrations of TDS in FGD wastewater.

[54] Sources: U.S. Environmental Protection Agency, "Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, Final Rule," 80 *Federal Register* 67838-67903, November 3, 2015; and U.S. Environmental Protection Agency, *Technical Development Document for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*, Document No. 821-R-15-007, September 2015.

Fly Ash Transport Water

Fly ash is the combustion residual of fine ash particles entrained in flue gases. Depending on the boiler design, as much as 70% to 80% of the ash from a pulverized coal furnace consists of fly ash. Many plants transport fly ash from the boiler using water as the motive force, known as sluicing, and fly ash transport water is one of the largest wastewater sources generated at coal-fired power plants. The steam electric power industry generates 209 billion gallons of fly ash transport water annually, with the average plant generating 4.27 MGD. It is typically treated in large surface impoundment systems. Untreated fly ash transport waters contain significant concentrations of metals and total suspended solids (TSS).

Because current NSPS regulations prohibit the discharge of pollutants in fly ash transport water, all plants built since 1982, as well as many existing generating units that have converted, already have dry fly ash handling systems that use air to transport fly ash to storage silos. Because dry fly ash handling practices do not generate fly ash transport water, converting to a dry system eliminates the discharge of fly ash transport water and the pollutants contained therein. EPA estimates that over 80% of existing coal- and petroleum coke-fired generating units use dry ash fly handling systems that utilize mechanical, pressure, or other technologies.

Fly ash transport water is one of the largest volume flows from coal-fired power plants. Studies have found that fly ash transport waters generated from wet systems at coal-fired power plants contain significant concentrations of metals, including arsenic, selenium, and mercury. EPA identified generating units at 145 plants that transport (i.e., sluice) fly ash with water to a surface impoundment to remove particulates from the wastewater by means of gravity. Thus, steam electric units generating wet fly ash transport water tend to be older units (e.g., more than 30 years old). Most of these plants are located east of the Mississippi River.

The 2015 revised rule establishes zero discharge effluent limitations and standards for discharges of pollutants in fly ash transport water, based on the use of dry fly ash handling technologies. Specifically, the technology basis for BAT is a dry vacuum system that employs a mechanical exhauster to pneumatically convey the fly ash from hoppers directly to a silo. As with FGD wastewater, surface impoundments are not effective at removing soluble forms of metals and nutrients.

Bottom Ash Transport Water

Bottom ash, sometimes referred to as "boiler slag," is the combustion residual of heavier ash particles collected at the bottom of a boiler. Since 70%-80% of the ash from a pulverized coal furnace consists of fly ash, the remaining 20%-30% is bottom ash. Like fly ash, bottom ash can be transported from the boiler using water and when it is, it is typically directed to an on-site ash impoundment for treatment. EPA found that bottom ash transport waters generated from wet systems at coal-fired power plants contain significant concentrations of the same metals found in fly ash transport water. Bottom ash transport water is an intermittent stream from steam electric units, with flow rates that typically are not as large as fly ash transport water flow rates, but it is still one of the larger volume flows. Moreover, significantly more plants generate bottom ash transport water than generate fly ash transport water. EPA identified 875 EGUs (348 plants)—67% of plants—that wet sluice (transport) at least a portion of their bottom ash to a surface impoundment or a dewatering bin for solids removal. EPA estimates that the steam electric industry generates a total of 297 billion gallons of bottom ash transport water annually, with the average plant generating 2.5 MGD. Amounts released to surface waters from impoundment overflow or discharge totaled 157 billion gallons in 2009.

According to EPA, many coal and oil-fired power plants design their bottom ash handling systems either to not use water to transport bottom ash away from the boiler or manage the transport water in a manner that eliminates or reduces the need to discharge bottom ash transport water to surface waters.

The 2015 revised rule requires zero discharge, using dry handling or closed-loop systems as the BAT technology basis for control of pollutants. About 20% of coal- and petroleum coke-fired units that generate bottom ash currently operate systems that eliminate the use of transport water; more than 80% of coal-fired generating units built in the last 20 years have installed dry bottom ash handling systems. Technologies to achieve zero discharge include mechanical drag systems, remote mechanical drag systems, and impoundment-based systems that are managed to eliminate all discharge of bottom ash transport water and associated pollutants. EPA found that more than half of the entities that would be subject to BAT requirements for bottom ash transport water are already employing zero discharge technologies or are planning to do so in the near future.

Combustion Residual Leachate from Surface Impoundments and Landfills

Combustion residuals include fly ash, bottom ash, and FGD solids, which are generally collected by or generated from air pollution control technologies. These residuals may be stored at the plant in on-site landfills or surface impoundments (ponds). Few steam electric power plants currently employ technologies other than surface impoundments for this waste. Combustion residual leachate is leachate from landfills or surface impoundments that contains combustion residuals. Water that comes in contact with the combustion residuals stored in a landfill or impoundment will be contaminated by metals and other contaminants present in the combustion residuals. The two sources of landfill combustion residual leachate are precipitation that percolates through the waste deposited in the landfill or impoundment and the liquids produced from the combustion residual placed in the landfill or impoundment. When a landfill or impoundment has reached its capacity, it will typically be closed to protect against environmental release of pollutants in the waste. However, these landfills or impoundments may continue to generate leachate, which is the liquid that drains or leaches from a landfill or surface impoundment. EPA estimated in 2009 that 150 to 200 coal-fired and petroleum coke-fired steam electric plants generated on average 0.57 MGD per plant of combustion residual leachate and that 100 to 110 plants discharged 80,000 to 90,000 gallons per day of combustion leachate residual.

In addition to leachate, stormwater that enters the impoundment or contacts and flows over the landfilled combustion residual would be contaminated with pollutants, such as heavy metals. Power plants manage these wastewaters in various ways. Stormwater collection systems typically consist of one or more small impoundments.

According to EPA, approximately 160 to 190 coal- and petroleum-fired steam electric power plants collect combustion residual leachate from either an impoundment and/or landfill. The majority (52%) of landfills and some impoundments (13%) have leachate collection systems, which may be combined with stormwater or sent to a separate impoundment. According to EPA, 63% of combustion residual landfills and 51% of combustion residual impoundments are lined. Unlined impoundments and landfills do not collect leachate that migrates away from the impoundment or landfill, which can potentially cause groundwater and/or drinking water contamination. Recently installed landfills and impoundments are more likely to be lined and to collect leachate.

Once collected, the landfill or impoundment leachate can be recycled back to the landfill or impoundment or within the plant, or it is discharged. Some plants discharge the effluent from leachate impoundments, while others send the leachate impoundment effluent to another impoundment that handles ash transport water or other systems.[55] Surface impoundments are the most common type of system used to treat combustion residual leachate from landfills and impoundments. Constructed wetlands are the next most commonly used treatment system. Physical/chemical and chemical precipitation technologies also have been demonstrated capable of treating pollutants in combustion residual leachate.

In the 2015 revised rule, EPA established effluent limitations and standards for existing sources equal to current BPT effluent limitations, based on technology of gravity settling in surface impoundments to remove suspended solids. For new sources, the technology basis of the 2015 rule is chemical precipitation/coprecipitation. Such systems are capable of achieving low effluent concentrations of various metals and are effective at removing many of the pollutants of concern present in leachate discharges to surface waters, and, like FGD wastewater, combustion residual leachate is similarly amenable to chemical precipitation treatment. However, as is the case with FGD wastewater, this technology is not effective at removing selenium, boron, and other parameters that contribute to TDS (e.g., magnesium, sodium).

Flue Gas Mercury Control (FGMC) System Wastewater

In response to recent Clean Air Act rules and other state regulations requiring limits on air emissions of mercury and other air toxics, power plants have been installing systems to improve removal of mercury from flue gas emissions. Thus, these systems are relatively new to the steam electric industry. FGMC systems remove mercury from the flue gas, so that it is not emitted into the air. In 2009, there were approximately 120 operating FGMC systems, with an additional 40 planned for installation by 2020. Approximately 90% of the currently operating FGMC systems are dry systems that add oxidizers to the coal prior to combustion and move the oxidized mercury in the wet FGD system. Using oxidizers does not generate a new wastestream, but the mercury concentration in FGD wastewater may be increased as a result, because oxidized mercury is more easily removed by the FGD system. About 6% of the currently operating systems involve injection of activated carbon into the flue gas to adsorb the mercury, which can generate a new wastestream at a plant that is likely sent to a surface impoundment.[56] According to EPA, coal-fired power plants can minimize or eliminate the discharge of FGMC particulate handling transport water using the same technologies that are available for fly ash, such as wet or dry vacuum pneumatic systems, pressure systems, or combined vacuum/pressure systems. EPA identified 6 plants that manage their FGMC waste with systems that use water to transport the waste to surface impoundments.

Under the final rule, the technology basis for existing and new sources would be zero discharge using dry handling technologies to store and dispose of fly ash without utilizing transport water. EPA found that this technology is available and well-demonstrated in the industry, since nearly all plants with FGMC systems use dry handling systems. Effluent limits based on dry handling would completely eliminate the discharge of pollutants in FGMC wastewater. EPA did not select BAT limitations for FGMC wastewater based on surface impoundments, because impoundments, which can remove particulate forms of metals and other pollutants, are not capable of removing dissolved metals and nitrates.

[55] At some plants, leachate from impoundments and landfills is not collected and can potentially migrate to nearby groundwaters or surface waters.

[56] The type of handling system (wet or dry) for the remaining 4% is unknown because they were planned FGMC systems as of 2009.

Gasification Wastewater

Integrated gasification combined cycle (IGCC) plants use coal or petroleum coke and subject it to high temperature and pressure to produce a synthetic gas, which is used as the fuel for combined cycle generating plants. After the synthetic gas is produced and prior to combustion, it undergoes cleaning to remove chlorides and other contaminants. This step can generate wastewater and condensate that require treatment prior to reuse or discharge. Two technologies in use to treat gasification wastewaters are vapor-compression evaporation systems and cyanide destruction systems.

The technology basis for the effluent limitations in the final rule is vapor-compression evaporation, which is currently used by the three operating IGCC plants in the United States. Surface impoundments were not selected as the basis for BAT limitations, because impoundments are not effective at removing the pollutants of concern in gasification wastewater, particularly dissolved solids.

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