United States
Environmental Protection
Agency

Office of Water
Washington, DC 20460

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Technical Development Document for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category

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GLOSSARY

Administrator – The Administrator of the U.S. Environmental Protection Agency.

Agency – U.S. Environmental Protection Agency.

BAT – Best available technology economically achievable, as defined by CWA Sections 301(b)(2)(A) and 304(b)(2)(B).

BCT – The best conventional pollutant control technology, applicable to discharges of conventional pollutants from existing industrial point sources, as defined by Sections 301(b)(2)(E) and 304(b)(4) of the CWA.

Bioaccumulation – General term describing a process by which chemicals are taken up by an organism either directly from exposure to a contaminated medium or by consumption of food containing the chemical, resulting in a net accumulation of the chemical by an organism due to uptake from all routes of exposure.

BMP – Best management practice.

Bottom ash –The ash, including boiler slag, which settles in the furnace or is dislodged from furnace walls. Economizer ash is included when it is collected with bottom ash.

BPT –The best practicable control technology currently available as defined by Sections 301(b)(1) and 304(b)(1) of the CWA.

CBI – Confidential Business Information.

CCR – Coal Combustion Residuals.

Clean Water Act (CWA) – The Federal Water Pollution Control Act Amendments of 1972 (33 U.S.C. 1251 et seq.), as amended *e.g.*, by the Clean Water Act of 1977 (Pub. L. 95–217), and the Water Quality Act of 1987 (Pub. L. 100–4).

Combustion residuals – Solid wastes associated with combustion-related power plant processes, including fly and bottom ash from coal-, petroleum coke-, or oil-fired units; FGD solids; FGMC wastes; and other wastewater treatment solids associated with combustion wastewater. In addition to the residuals that are associated with coal combustion, this also includes residuals associated with the combustion of other fossil fuels.

Combustion residual leachate – Leachate from landfills or surface impoundments containing combustion residuals. Leachate is composed of liquid, including any suspended or dissolved constituents in the liquid, that has percolated through waste or other materials emplaced in a landfill, or that passes through the surface impoundment's containment structure (*e.g.*, bottom, dikes, berms). Combustion residual leachate includes seepage and/or leakage from a combustion residual landfill or impoundment unit. Combustion residual leachate includes wastewater from landfills and surface impoundments located on non-adjoining property when under the operational control of the permitted facility.

Direct discharge – (a) Any addition of any "pollutant" or combination of pollutants to "waters of the United States" from any "point source," or (b) any addition of any pollutant or combination of pollutant to waters of the "contiguous zone" or the ocean from any point source other than a vessel or other floating craft which is being used as a means of transportation. This definition includes additions of pollutants into waters of the United States from: surface runoff which is collected or channeled by man; discharges though pipes, sewers, or other conveyances owned by a State, municipality, or other person which do not lead to a treatment works; and discharges through pipes, sewers, or other conveyances, leading into privately owned treatment works. This term does not include an addition of pollutants by any "indirect discharger."*Direct discharger* – A facility that discharges treated or untreated wastewaters into waters of the U.S.

DOE – Department of Energy.

Dry bottom ash handling system – A system that does not use water as the transport medium to convey bottom ash away from the boiler. It includes systems that collect and convey the ash without any use of water, as well as systems in which bottom ash is quenched in a water bath and then mechanically or pneumatically conveyed away from the boiler. Dry bottom ash handling systems do not include wet sluicing systems (such as remote MDS or complete recycle systems).

Dry fly ash handling system – A system that does not use water as the transport medium to convey fly ash away from particulate collection equipment.

Effluent limitation – Under CWA section 502(11), any restriction, including schedules of compliance, established by a state or the Administrator on quantities, rates, and concentrations of chemical, physical, biological, and other constituents which are discharged from point sources into navigable waters, the waters of the contiguous zone, or the ocean, including schedules of compliance.

EIA – Energy Information Administration.

ELGs – Effluent limitations guidelines and standards.

EO – Executive Order.

EPA – U.S. Environmental Protection Agency.

ESP – Electrostatic precipitator.

Facility – Any NPDES "point source" or any other facility or activity (including land or appurtenances thereto) that is subject to regulation under the NPDES program.

FGD – Flue gas desulfurization.

FGD wastewater – Wastewater generated specifically from the wet flue gas desulfurization scrubber system that comes into contact with the flue gas or the FGD solids, including but not limited to, the blowdown or purge from the FGD scrubber system, overflow or underflow from the solids separation process, FGD solids wash water, and the filtrate from the solids dewatering process. Wastewater generated from cleaning the FGD scrubber, cleaning FGD solids separation equipment, cleaning FGD solids dewatering equipment, or that is collected in floor drains in the FGD process area is not considered FGD wastewater.

FGD gypsum – Gypsum generated specifically from the wet FGD scrubber system, including any solids separation or solids dewatering processes.

FGMC – Flue gas mercury control.

FGMC system – An air pollution control system installed or operated for the purpose of removing mercury from flue gas.

FGMC wastewater – Wastewater generated from an air pollution control system installed or operated for the purpose of removing mercury from flue gas. This includes fly ash collection systems when the particulate control system follows sorbent injection or other controls to remove mercury from flue gas. FGD wastewater generated at plants using oxidizing agents to remove mercury in the FGD system and not in a separate FGMC system is not included in this definition.

Fly ash – The ash that is carried out of the furnace by a gas stream and collected by a capture device such as a mechanical precipitator, electrostatic precipitator, and/or fabric filter. Economizer ash is included in this definition when it is collected with fly ash. Ash is not included in this definition when it is collected in wet scrubber air pollution control systems whose primary purpose is particulate removal.

Gasification wastewater – Any wastewater generated at an integrated gasification combined cycle operation from the gasifier or the syngas cleaning, combustion, and cooling processes. Gasification wastewater includes, but is not limited to the following: sour/grey water; CO_2/steam stripper wastewater; sulfur recovery unit blowdown, and wastewater resulting from slag handling or fly ash handling, particulate removal, halogen removal, or trace organic removal. Air separation unit blowdown, noncontact cooling water, and runoff from fuel and/or byproduct piles are not considered gasification wastewater. Wastewater that is collected intermittently in floor drains in the gasification process areas from leaks, spills and cleaning occurring during normal operation of the gasification operation is not considered gasification wastewater.

Ground water – Water that is found in the saturated part of the ground underneath the land surface.

IGCC – Integrated gasification combined cycle.

Indirect discharge – Wastewater discharged or otherwise introduced to a POTW.

IPM – Integrated Planning Model.

Landfill – A disposal facility or part of a facility where solid waste, sludges, or other process residuals are placed in or on any natural or manmade formation in the earth for disposal and which is not a storage pile, a land treatment facility, a surface impoundment, an underground injection well, a salt dome or salt bed formation, an underground mine, a cave, or a corrective action management unit.

Low volume waste sources – Taken collectively as if from one source, wastewater from all sources except those for which specific limitations are otherwise established in this part. Low volume waste sources include, but are not limited to the following: wastewaters from ion exchange water treatment systems, water treatment evaporator blowdown, laboratory and sampling streams, boiler blowdown, floor drains, cooling tower basin cleaning wastes, recirculating house service water systems, and wet scrubber air pollution control systems whose primary purpose is particulate removal. Sanitary wastes, air conditioning wastes, and wastewater from carbon capture or sequestration systems are not included in this definition.

MDS – Mechanical drag system.

Mechanical Drag System – Bottom ash handling system that collects bottom ash from the bottom of the boiler in a water-filled trough. The water bath in the trough quenches the hot bottom ash as it falls from the boiler and seals the boiler gases. A drag chain operates in a continuous loop to drag bottom ash from the water trough up an incline, which dewaters the bottom ash by gravity, draining the water back to the trough as the bottom ash moves upward. The dewatered bottom ash is often conveyed to a nearby collection area, such as a small bunker outside the boiler building, from which it is loaded onto trucks and either sold or transported to a landfill. The MDS is considered a dry bottom ash handling system because the ash transport mechanism is mechanical removal by the drag chain, not the water.

Metal cleaning wastes – Any wastewater resulting from cleaning [with or without chemical cleaning compounds] any metal process equipment including, but not limited to, boiler tube cleaning, boiler fireside cleaning, and air preheater cleaning.

Mortality – Death rate or proportion of deaths in a population.

NAICS – North American Industry Classification System.

NPDES – National Pollutant Discharge Elimination System.

NSPS – New Source Performance Standards.

Oil-fired unit – A generating unit that uses oil as the primary or secondary fuel source and does not use a gasification process or any coal or petroleum coke as a fuel source. This definition does not include units that use oil only for start up or flame-stabilization purposes.

ORCR – Office of Resource Conservation and Recovery.

Point source – Any discernable, confined, and discrete conveyance, including but not limited to, any pipe, ditch, channel, tunnel, conduit, well, discrete fissure, container, rolling stock, concentrated animal feeding operation, or vessel or other floating craft from which pollutants are or may be discharged. The term does not include agricultural stormwater discharges or return flows from irrigated agriculture. See CWA section 502(14), 33 U.S.C. 1362(14); 40 CFR § 122.2.

POTW – Publicly owned treatment works. See CWA section 212, 33 U.S.C. 1292; 40 CFR §§ 122.2, 403.3

Primary particulate collection system – The first place in the process where fly ash is collected, such as collection at an ESP or baghouse. For example, a coal combustion particulate collection system may include multiple steps including a primary particulate collection step such as ESP followed by other processes such as a fabric filter which would constitute a secondary particulate collection system.

PSES – Pretreatment Standards for Existing Sources.

PSNS – Pretreatment Standards for New Sources.

Publicly Owned Treatment Works – Any device or system, owned by a state or municipality, used in the treatment (including recycling and reclamation) of municipal sewage or industrial wastes of a liquid nature that is owned by a state or municipality. This includes sewers, pipes, or other conveyances only if they convey wastewater to a POTW providing treatment. See CWA section 212, 33 U.S.C. 1292; 40 CFR §§ 122.2, 403.3.

RCRA – The Resource Conservation and Recovery Act of 1976, 42 U.S.C. 6901 et seq.

Remote MDS – Bottom ash handling system that collects bottom ash at the bottom of the boiler, then uses transport water to sluice the ash to a remote MDS that dewaters bottom ash using a similar configuration as the MDS. The remote MDS is considered a wet bottom ash handling system because the ash transport mechanism is water.

RFA – Regulatory Flexibility Act.

SBA – Small Business Administration.

Sediment – Particulate matter lying below water.

Steam electric power plant wastewater – Wastewaters associated with or resulting from the combustion process, including ash transport water from coal-, petroleum coke-, or oil-fired units; air pollution control wastewater (*e.g.*, FGD wastewater, FGMC wastewater, carbon capture wastewater); and leachate from landfills or surface impoundments containing combustion residuals.

Surface water – All waters of the United States, including rivers, streams, lakes, reservoirs, and seas.

Toxic pollutants – As identified under the CWA, 65 pollutants and classes of pollutants, of which 126 specific substances have been designated priority toxic pollutants. See Appendix A to 40 CFR 423.

Transport water – Wastewater that is used to convey fly ash, bottom ash, or economizer ash from the ash collection or storage equipment, or boiler, and has direct contact with the ash. Transport water does not include low volume, short duration discharges of wastewater from minor leaks (e.g., leaks from valve packing, pipe flanges, or piping) or minor maintenance events (e.g., replacement of valves or pipe sections).*UMRA* – Unfunded Mandates Reform Act.

Wet bottom ash handling system – A system in which bottom ash is conveyed away from the boiler using water as a transport medium. Wet bottom ash systems typically send the ash slurry to dewatering bins or a surface impoundment. Wet bottom ash handling systems include systems that operate in conjunction with a traditional wet-sluicing system to recycle all bottom ash transport water (remote MDS or complete recycle system).

Wet FGD system – Wet FGD systems capture sulfur dioxide from the flue gas using a sorbent that has mixed with water to form a wet slurry, and that generates a water stream that exits the FGD scrubber absorber.

Wet fly ash handling system – A system that conveys fly ash away from particulate removal equipment using water as a transport medium. Wet fly ash systems typically dispose of the ash slurry in a surface impoundment.

SECTION 1 BACKGROUND

This section provides background information on the development of revised effluent limitations guidelines and standards (ELGs) for the Steam Electric Power Generating Point Source Category (Steam Electric Category). Sections 1.1 and 1.2 discuss the legal authority and regulatory background for the final rule. Section 1.3 presents a history of Steam Electric Category rulemaking activities.

In addition to this report, there are other reports that support the development of the Steam Electric ELGs:

- *Environmental Assessment for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (EA Report)*, Document No. EPA-821-R-15-006. This report summarizes the environmental and human health improvements that result from implementation of the revised ELGs.
- *Benefits and Cost Analysis for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (BCA)*, Document No. EPA-821-R-15-005. This report summarizes the societal benefits and costs expected to result from implementation of the ELGs.
- *Regulatory Impact Analysis for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (RIA)*, Document No. EPA-821-R-15-004. This report presents a profile of the steam electric industry, a summary of the costs and impacts associated with the regulatory options, and an assessment of the ELGs' impact on employment and small businesses.

The ELGs for the Steam Electric Category are based on data generated or obtained in accordance with EPA's Quality Policy and Information Quality Guidelines. EPA's quality assurance (QA) and quality control (QC) activities for this rulemaking include developing, approving, and implementing Quality Assurance Project Plans for the use of environmental data generated or collected from sampling and analyses, existing databases, and literature searches, and for developing any models that used environmental data.

1.1 LEGAL AUTHORITY

EPA is finalizing revisions of the ELGs for the Steam Electric Power Generating Point Source Category (40 Code of Federal Regulations (CFR) 423) under the authority of sections 301, 304, 306, 307, 308, 402, and 501 of the Clean Water Act, 33 U.S.C. 1311, 1314, 1316, 1317, 1318, 1342, and 1361.

1.2 CLEAN WATER ACT

Congress passed the CWA to "restore and maintain the chemical, physical, and biological integrity of the Nation's waters." 33 U.S.C. 1251(a). In order to achieve this objective, the Act has, as a national goal, the elimination of the discharge of all pollutants into the nation's waters. 33 U.S.C. 1251(a)(1). The CWA establishes a comprehensive program for protecting our nation's waters. Among its core provisions, the CWA prohibits the discharge of pollutants from a point source to waters of the U.S., except as authorized under the CWA. Under section 402 of the CWA, 33 U.S.C. 1342, discharges may be authorized through a National Pollutant Discharge Elimination System (NPDES) permit. The CWA establishes a dual approach for these permits, technology-based controls that establish a floor of performance for all dischargers, and water quality-based effluent limitations, where the technology-based effluent limitations are insufficient to meet applicable water quality standards (WQS). To serve as the basis for the technology-based controls, the CWA authorizes EPA to establish national technology-based effluent limitations guidelines and new source performance standards for discharges from categories of point sources (such as industrial, commercial, and public sources) that occur directly into waters of the U.S.

The CWA also authorizes EPA to promulgate nationally applicable pretreatment standards that control pollutant discharges from sources that discharge wastewater indirectly to waters of the U.S., through sewers flowing to POTWs, as outlined in sections 307(b) and (c) of the CWA, 33 U.S.C. 1317(b) and (c). EPA establishes national pretreatment standards for those pollutants in wastewater from indirect dischargers that pass through, interfere with, or are otherwise incompatible with POTW operations. Generally, pretreatment standards are designed to ensure that wastewaters from direct and indirect industrial dischargers are subject to similar levels of treatment. See CWA section 301(b), 33 U.S.C. 1311(b). In addition, POTWs are required to implement local treatment limits applicable to their industrial indirect dischargers to satisfy any local requirements. See 40 CFR § 403.5.

Direct dischargers (those discharging directly to surface waters) must comply with effluent limitations in NPDES permits. Indirect dischargers, who discharge through POTWs, must comply with pretreatment standards. Technology-based effluent limitations and standards in NPDES permits are derived from effluent limitations guidelines (CWA sections 301 and 304, 33 U.S.C. 1311 and 1314) and new source performance standards (CWA section 306, 33 U.S.C. 1316) promulgated by EPA, or based on best professional judgment (BPJ) where EPA has not promulgated an applicable effluent limitation guideline or new source performance standard (CWA section 402(a)(1)(B), 33 U.S.C. 1342(a)(1)(B)). Additional limitations are also required in the permit where necessary to meet WQS. CWA section 301(b)(1)(C), 33 U.S.C. 1311(b)(1)(C). The ELGs are established by EPA regulation for categories of industrial dischargers and are based on the degree of control that can be achieved using various levels of pollution control technology, as specified in the Act (*e.g.*, BPT, BCT, BAT; see below).

EPA promulgates national ELGs for major industrial categories for three classes of pollutants: (1) conventional pollutants (TSS, oil and grease, biochemical oxygen demand (BOD_5), fecal coliform, and pH), as outlined in CWA section 304(a)(4) and 40 CFR § 401.16; (2) toxic pollutants (*e.g.*, toxic metals such as arsenic, mercury, selenium, and chromium; toxic organic pollutants such as benzene, benzo-a-pyrene, phenol, and naphthalene), as outlined in CWA section 307(a), 33 U.S.C. 1317(a); 40 CFR § 401.15 and 40 CFR part 423 appendix A; and (3) nonconventional pollutants, which are those pollutants that are not categorized as conventional or toxic (*e.g.*, ammonia-N, phosphorus, and TDS).

EPA establishes ELGs based on the performance of well-designed and well-operated control and treatment technologies. The legislative history of CWA section 304(b), which is the heart of the effluent guidelines program, describes the need to press toward higher levels of control through research and development of new processes, modifications, replacement of obsolete plants and processes, and other improvements in technology, taking into account the cost of controls. Congress has also stated that EPA need not consider water quality impacts on individual water bodies as the guidelines are developed; see Statement of Senator Muskie (principal author) (October 4, 1972), reprinted in Legislative History of the Water Pollution Control Act Amendments of 1972, at 170. (U.S. Senate, Committee on Public Works, Serial No. 93–1, January 1973).

There are four types of standards applicable to direct dischargers, and two types of standards applicable to indirect dischargers, described in detail below.

1.2.1 Best Practicable Control Technology Currently Available (BPT)

Traditionally, EPA establishes effluent limitations based on BPT by reference to the average of the best performances of facilities within the industry, grouped to reflect various ages, sizes, processes, or other common characteristics. EPA can promulgate BPT effluent limitations for conventional, toxic, and nonconventional pollutants. In specifying BPT, EPA looks at a number of factors. EPA first considers the cost of achieving effluent reductions in relation to the effluent reduction benefits. The Agency also considers the age of equipment and facilities, the processes employed, engineering aspects of the control technologies, any required process changes, non-water quality environmental impacts (including energy requirements), and such other factors as the Administrator deems appropriate. See CWA section 304(b)(1)(B), 33 U.S.C. 1314(b)(1)(B). If, however, existing performance is uniformly inadequate, EPA may establish limitations based on higher levels of control than what is currently in place in an industrial category, when based on an Agency determination that the technology is available in another category or subcategory and can be practically applied.

1.2.2 Best Conventional Pollutant Control Technology (BCT)

The 1977 amendments to the CWA require EPA to identify additional levels of effluent reduction for conventional pollutants associated with BCT for discharges from existing industrial point sources. In addition to other factors specified in section 304(b)(4)(B), 33 U.S.C. 1314(b)(4)(B), the CWA requires that EPA establish BCT limitations after consideration of a two-part "cost reasonableness" test. EPA explained its methodology for the development of BCT limitations on July 9, 1986 (51 FR 24974). Section 304(a)(4) designates the following as conventional pollutants: BOD_5, TSS, fecal coliform, pH, and any additional pollutants defined by the Administrator as conventional. The Administrator designated oil and grease as a conventional pollutant on July 30, 1979 (44 FR 44501; 40 CFR § 401.16).

1.2.3 Best Available Technology Economically Achievable (BAT)

BAT represents the second level of stringency for controlling direct discharges of toxic and nonconventional pollutants. As the statutory phrase intends, EPA considers the technological availability and the economic achievability in determining what level of control represents BAT. CWA section 301(b)(2)(A), 33 U.S.C. 1311(b)(2)(A). Other statutory factors that EPA considers in assessing BAT are the cost of achieving BAT effluent reductions, the age of equipment and facilities involved, the process employed, potential process changes, non-water quality environmental impacts (including energy requirements), and such other factors as the Administrator deems appropriate. The Agency retains considerable discretion in assigning the weight to be accorded these factors. Weyerhaeuser Co. v. Costle, 590 F.2d 1011, 1045 (D.C. Cir. 1978). Generally, EPA determines economic achievability based on the effect of the cost of compliance with BAT limitations on overall industry and subcategory (if applicable) financial conditions. BAT is intended to reflect the highest performance in the industry, and it may reflect a higher level of performance than is currently being achieved based on technology transferred from a different subcategory or category, bench scale or pilot studies, or foreign plants. Am. Paper Inst. v. Train, 543 F.2d 328, 353 (D.C. Cir. 1976); Am. Frozen Food Inst. v. Train, 539 F.2d 107, 132 (D.C. Cir. 1976). BAT may be based upon process changes or internal controls, even when these technologies are not common industry practice. See Am. Frozen Food Inst., 539 F.2d at 132, 140; Reynolds Metals Co. v. EPA, 760 F.2d 549, 562 (4th Cir. 1985); Cal. & Hawaiian Sugar Co. v. EPA, 553 F.2d 280, 285-88 (2nd Cir. 1977).

1.2.4 Best Available Demonstrated Control Technology (BADCT)/New Source Performance Standards (NSPS)

NSPS reflect “the greatest degree of effluent reduction” that is achievable based on the “best available demonstrated control technology” (BADCT), “including, where practicable, a standard permitting no discharge of pollutants.” CWA section 306(a)(1), 33 U.S.C. 1316(a)(1). Owners of new facilities have the opportunity to install the best and most efficient production processes and wastewater treatment technologies. As a result, NSPS generally represent the most stringent controls attainable through the application of BADCT for all pollutants (that is, conventional, nonconventional, and toxic pollutants). In establishing NSPS, EPA is directed to take into consideration the cost of achieving the effluent reduction and any non-water quality environmental impacts and energy requirements. CWA section 306(b)(1)(B), 33 U.S.C. 1316(b)(1)(B).

1.2.5 Pretreatment Standards for Existing Sources (PSES)

Section 307(b) of the CWA, 33 U.S.C. 1317(b), authorizes EPA to promulgate pretreatment standards for discharges of pollutants to POTWs. PSES are designed to prevent the discharge of pollutants that pass through, interfere with, or are otherwise incompatible with the operation of POTWs. Categorical pretreatment standards are technology-based and are analogous to BPT and BAT effluent limitations guidelines, and thus the Agency typically considers the same factors in promulgating PSES as it considers in promulgating BAT. Congress intended for the combination of pretreatment and treatment by the POTW to achieve the level of treatment that would be required if the industrial source were making a direct discharge. Conf. Rep. No. 95-830, at 87 (1977), reprinted in U.S. Congress. Senate Committee on Public Works (1978), A Legislative History of the CWA of 1977, Serial No. 95-14 at 271 (1978). The General Pretreatment Regulations, which set forth the framework for the implementation of categorical pretreatment standards, are found at 40 CFR part 403. These regulations establish pretreatment standards that apply to all non-domestic dischargers. See 52 FR 1586 (January 14, 1987).

1.2.6 Pretreatment Standards for New Sources (PSNS)

Section 307(c) of the CWA, 33 U.S.C. 1317(c), authorizes EPA to promulgate PSNS at the same time it promulgates NSPS. As is the case for PSES, PSNS are designed to prevent the discharge of any pollutant into a POTW that interferes with, passes through, or is otherwise incompatible with the POTW. In selecting the PSNS technology basis, the Agency generally considers the same factors it considers in establishing NSPS, along with the results of a pass-through analysis. Like new sources of direct discharges, new sources of indirect discharges have the opportunity to incorporate into their operations the best available demonstrated technologies. As a result, EPA typically promulgates pretreatment standards for new sources based on best available demonstrated control technology for new sources. See Nat'l Ass'n of Metal Finishers v. EPA, 719 F.2d 624, 634 (3rd Cir. 1983).

1.3 Regulatory History of the Steam Electric Power Generating Point Source Category

This section presents a brief history of Steam Electric Category rulemaking activities. Section 1.3.1 discusses the existing steam electric industry wastewater discharge regulations. Section 1.3.2 discusses the Detailed Study of the Steam Electric Category. Section 1.3.3 discusses other statutes and regulatory requirements affecting this industry.

1.3.1 Discharge Requirements Established in Prior Rulemakings

EPA first issued ELGs for the Steam Electric Category in 1974 with subsequent revisions in 1977 and 1982. These previously established ELGs applied to a subset of the electric power industry, namely those plants "primarily engaged in the generation of electricity…which results primarily from a process utilizing fossil-type fuel (coal, oil, or gas) or nuclear fuel in conjunction with a thermal cycle employing the steam water system as the thermodynamic medium." The previously established ELGs did not apply to discharges from generating units that primarily use a non-fossil or non-nuclear fuel source (*e.g.*, wood waste, municipal solid waste) to power the steam electric generators, nor did they apply to generating units operated by establishments that are not primarily engaged in generating electricity for distribution and sale.

The Steam Electric ELGs are codified at 40 CFR 423 and these prior rulemakings established requirements for the following wastestreams:

- Once-through cooling water.
- Cooling tower blowdown.
- Fly ash transport water.
- Bottom ash transport water.
- Metal cleaning wastes, including chemical metal cleaning wastes.
- Coal pile runoff.
- Low-volume waste sources [40 CFR 423.11(b)].

As described in Section 1.3.2, the previously established ELGs for the steam electric power generating industry, which EPA last updated in 1982, do not adequately address the toxic pollutants discharged from this industry sector, nor have they kept pace with process changes that have occurred over the last three decades. The development of new technologies for generating electric power (*e.g.*, coal gasification) and the widespread implementation of air pollution controls (*e.g.*, flue gas desulfurization (FGD), selective catalytic reduction (SCR), and flue gas mercury controls (FGMC)) have altered existing wastestreams and/or created new sources of wastewater at many power plants, particularly coal-fired plants.

1.3.2 Detailed Study of the Steam Electric Power Generating Point Source Category

Section 304 of the CWA requires EPA to periodically review all ELGs to determine whether revisions are warranted. In addition, section 304(m) of the CWA requires EPA to develop and publish, biennially, a plan that establishes a schedule for reviewing and revising promulgated national effluent guidelines required by CWA section 304(b). During the 2005 annual review of the existing effluent guidelines for all categories, EPA identified the regulations governing the Steam Electric Power Generating Point Source Category for possible revision. At that time, publicly available data reported through the NPDES permit program and the Toxics Release Inventory (TRI) indicated that the industry ranked high in discharges of toxic and nonconventional pollutants. Because of these findings, EPA initiated a more detailed study of the category to determine if the effluent guidelines should be revised.

During the detailed study, EPA collected information on wastewater characteristics and treatment technologies through site visits, wastewater sampling, a data request sent to a limited number of companies, and various secondary data sources (Section 3 summarizes these data collection activities). EPA focused these data collection activities on certain discharges from coal-fired steam electric power plants (referred to in this report as "coal-fired power plants"). Based on the data collected, EPA determined that most of the toxic loadings for this category are associated with metals and nonmetallic elements, such as selenium, present in wastewater discharges, and that the wastestreams contributing the majority of these pollutants are associated with ash transport and wet FGD systems. EPA also identified several wastestreams that are relatively new to the industry (*e.g.*, carbon capture wastewater) and wastestreams for which there are little characterization data (*e.g.*, gasification wastewater). See Section 4 and Section 7 for more information on these practices.

During the study, EPA found that the use of wet FGD systems to control sulfur dioxide (SO_2) emissions increased significantly since the last revision of the effluent guidelines in 1982 and its use was projected to continue increasing as steam electric power plants took steps to address federal and state air pollution control requirements. EPA also found that FGD wastewaters generally contain significant levels of metals and other pollutants and that advanced treatment technologies are available to treat the FGD wastewater. However, most plants were using surface impoundments designed primarily to remove suspended solids from FGD wastewater.

EPA also determined that technologies are available for handling the fly ash and bottom ash generated at a plant without using any water or at least eliminating the discharge of any ash transport water. EPA found that fly ash and bottom ash transport waters are generated in large quantities from wet systems at coal-fired power plants and contain significant concentrations of metals, including arsenic and mercury. Additionally, EPA determined that some of the metals are present primarily in the dissolved phase and generally are not removed in the surface impoundments that are used to treat these wastestreams. Based on these findings, EPA determined that there are technologies readily available to reduce or eliminate the discharge of pollutants contained in fly ash and bottom ash transport water.

Finally, EPA determined that FGD wastewater and ash transport waters contain pollutants that can have detrimental impacts to the environment. EPA reviewed publicly available data and found documented environmental impacts that were attributable to discharges from surface impoundments or discharges from leachate generated from landfills and impoundments containing coal combustion residuals (CCR). EPA determined that there are a number of pollutants present in wastewaters generated at coal-fired power plants that can affect the environment, including metals and nonmetallic elements (*e.g.*, arsenic, selenium, mercury), TDS, and nutrients. EPA found that wastewaters generated at coal-fired power plants have caused a wide range of harm to aquatic life.

Overall, EPA found from the detailed study that the industry is generating new wastestreams that during the previous rulemakings either were not evaluated or were evaluated to only a limited extent due to insufficient characterization data. Such wastestreams include FGD wastewater, FGMC wastewater, carbon capture wastewater, and gasification wastewater. EPA also found that these wastestreams, as well as other wastewaters generated at coal-fired power plants (*e.g.*, fly ash and bottom ash transport water, combustion residual leachate), contain pollutants in concentrations and mass loadings that are causing documented environmental impacts and that treatment technologies are available to reduce or eliminate the pollutant discharges from these wastewaters.

After completing the detailed study in 2009, EPA determined that the current regulations have not kept pace with the significant changes that have occurred in this industry over the last three decades. EPA's analysis of the wastewater discharges associated with steam electric power generation led the Agency, in September 2009, to announce plans to revise the effluent guidelines.

1.3.3 Other Statutes and Regulatory Requirements Affecting Management of Steam Electric Power Generating Wastewaters

EPA recognizes that this rule does not exist in isolation. EPA is taking action to reduce emissions, discharges, and other environmental impacts associated with steam electric power plants. These actions, which are being implemented by several different EPA offices (*i.e.*, Office of Air and Radiation (OAR), Office of Solid Waste and Emergency Response (OSWER), Office of Water (OW)), include establishing new regulatory requirements that may affect the generation and composition of wastewater discharged from steam electric power plants. For example, since proposal, EPA has promulgated the Cooling Water Intake Structures rule (79 FR 48300) for existing facilities, the Coal Combustion Residuals rule (80 FR 21302), the Clean Power Plan (signed on August 3, 2015), and the Carbon Pollution Standard for New Power Plants (signed on August 3, 2015). EPA made every effort to appropriately account for these other rules in its many analyses for this rule. In some cases, EPA performed two sets of parallel analyses to demonstrate how the other rules affect this final rule. This section provides a brief overview of these statutes and the regulatory requirements associated with steam electric power plants.

1. Mercury and Air Toxics Standards (MATS)

When the Clean Air Act (CAA) was amended in 1990, EPA was directed to control mercury and other hazardous air pollutants from major sources of emissions to the air. For power plants using fossil fuels, the amendments required EPA to conduct a study of hazards to public health reasonably anticipated to occur as a result of the emissions of hazardous air pollutants from electric steam generating units (CAA Section 112(n)(1)(A)). The CAA amendments also required and the Administrator to make a finding as to whether regulation was appropriate and necessary after considering the results of the study. In 2000, the Administrator found and reaffirmed in December of 2011 that regulation of hazardous air pollutants, including mercury, from coal- and oil-fired power plants was appropriate and necessary (65 FR 79825 (Dec. 20, 2000)).

EPA published the reaffirmation and the final MATS rule on February 16, 2012 (77 FR 9304). The rule established standards that will reduce emissions of hazardous air pollutants including metals (*e.g.*, mercury, arsenic, chromium, nickel) and acid gases (*e.g.*, hydrochloric acid, hydrofluoric acid). Steam electric power plants may use any number of practices, technologies, and strategies to meet the new emission limits, including wet and dry scrubbers, dry sorbent injection systems, activated carbon injection systems, and fabric filters. Sources have up to three years to come into compliance and permitting agencies – usually the state agency – can give a source an additional year if it is needed. Many sources, therefore are already in compliance with MATS and all must be in compliance by April 15, 2016. In *Michigan v. EPA*, the Supreme Court reversed on narrow grounds a portion of the D.C. Circuit decision upholding the MATS rule, finding that EPA erred by not considering cost when determining that regulation of EGUs was "appropriate" pursuant to CAA section 112(n)(1). 135 S.Ct. 192 (2015). The case was remanded to the D.C. Circuit for further proceedings, and the MATS rule currently remains in place. EPA has requested that the D.C. Circuit remand MATS without vacatur. Given the existing record demonstrating that EPA considered cost throughout the MATS rulemaking, the Agency believes it can meet an ambitious schedule on remand and intends to finalize our analysis of cost for the appropriate and necessary finding as close to April 15, 2016 as possible. If EPA reaffirms that finding on remand, there is no reason for EPA to revisit any other portions of the Rule. In the meantime, consistent with the Rule's April 16, 2015 compliance date, the many units already in compliance represent half of the domestic coal capacity, and many of those that received a one-year extension will have already made significant investments or entered into contractual commitments in order to meet the extended deadline. Since the final MATS rule remains in effect and many sources are already in compliance, MATS is included in the analytical baseline for this final rule.

2. Cross-State Air Pollution Rule (CSAPR)

EPA promulgated the CSAPR in 2011 to require 28 states in the eastern half of the United States to significantly improve air quality by reducing power plant emissions of SO_2, nitrogen oxides (NO_x), and/or ozone-season NO_x that cross state lines and significantly contribute to ground-level ozone and/or fine particle pollution problems in other states. The emissions of SO_2, NO_x, and ozone-season NO_x react in the atmosphere to form PM2.5 and ground-level ozone and are transported long distances, making it difficult for a number of states to meet the national clean air standards that Congress directed EPA to establish to protect public health. The U.S. Court of Appeals for the D.C. Circuit stayed the CSAPR on December 30, 2011, and on August 21, 2012, issued an opinion vacating the rule and ordering EPA to continue administering the Clean Air Interstate Rule (*EME Homer City Generation, L.P. v. EPA*, 696 F.3d 7 (D.C.Cir. 2012)). On March 29, 2013, the United States filed a petition asking the Supreme Court to review the D.C. Circuit decision.

On April 29, 2014, the U.S. Supreme Court issued an opinion reversing the August 21, 2012, D.C. Circuit decision that had vacated CSAPR. Following the remand of the case to the D.C. Circuit, EPA requested that the court lift the CSAPR stay and extend the CSAPR compliance deadlines by 3 years. On October 23, 2014, the D.C. Circuit granted EPA's request. Accordingly, CSAPR Phase 1 implementation is now scheduled for 2015, with Phase 2 beginning in 2017.

3. Clean Power Plan (CPP)

On August 3, 2015, EPA issued the Clean Power Plan (CPP), which establishes CO_2 emission guidelines for existing fossil fuel-fired electric utility generating units (EGUs). The CPP will achieve significant reductions in CO_2 emissions by 2030. The final CPP establishes a CO_2 emission performance rate for each of two subcategories of fossil fuel-fired EGUs – fossil fuel-fired electric steam generating units and natural gas combined cycle generating units. The emission performance rates reflect the "best system of emission reductions … adequately demonstrated" for CO_2 emissions from each EGU subcategory. The rule establishes guidelines for the development, submittal and implementation of state plans to implement the CO_2 emission performance rates. State plans will ensure that the power plants in their state either individually, together, or in combination with other measures achieve an interim CO_2 emission performance rate, a rate based goal, or a mass-based goal over the period of 2022 to 2029, and final CO_2 emission performance rate or goal in 2030. Each state will have the flexibility to select the measures it prefers in order to achieve the CO_2 performance rates for its affected plants or meet the equivalent statewide rate- or mass-based goal. States instead may adopt a model rule that EPA proposed on August 3, 2015. It provides a cost effective pathway for states to adopt a trading system supported by EPA.

States can tailor their plans to meet their respective energy, environmental and economic needs and goals, and those of their local communities by relying on a diverse set of energy resources. This flexibility helps to protect electric reliability, provides affordable electricity, and recognizes the investments that states and power companies are already making. States, cities, and businesses across the country are already taking action to address the risks of climate change. EPA's final rule builds on those actions and is flexible, taking into consideration that different states have a different mix of sources and opportunities and reflecting the important role of states as full partners with the federal government in cutting pollution. This final rule will maintain an affordable, reliable energy system, while cutting pollution and protecting our health and environment now and for future generation.

Also on August 3, 2015, EPA proposed a Federal Plan, which EPA would implement in any state that does not submit an approvable state plan. The proposal includes two different plan types for a federal plan – a rate-based trading plan and a mass-based trading plan. Both plan types would require affected EGUs to meet emissions standards using the CO_2 performance rates in the CPP and would achieve the same levels of emissions performance as required of state plans under the CPP.

4. Carbon Pollution Standard for New Power Plants

On August 3, 2015, EPA issued the Carbon Pollution Standards for New, Modified and Reconstructed fossil fuel-fired power plants. The final standards apply to newly constructed sources built, and to those that may be built in the future and to existing units that meets certain specific conditions described in the Clean Air Act and implementing regulations, for being "modified" or "reconstructed." In this final action, EPA established separate standards for two types of fossil-fuel fired sources: stationary combustion turbines and electric utility steam generating units.

These final performance standards reflect the degree of emission limitation achievable through the application of the best system of emission reduction that EPA has determined has been adequately demonstrated for each type of unit. Because these standards are consistent with current industry investment patterns, these standards are not expected to have notable costs and are not projected to affect electricity prices or reliability.

5. Cooling Water Intake Structures (CWA Section 316(b))

Section 316(b) of the CWA, 33 U.S.C. 1326(b), requires that standards applicable to point sources under CWA sections 301 and 306 require that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available to minimize adverse environmental impacts. Each year, these facilities withdraw large volumes of water from lakes, rivers, estuaries, or oceans to use in their facilities. In the process, these facilities remove billions of aquatic organisms from waters of the United States, including fish, fish larvae and eggs, crustaceans, shellfish, sea turtles, marine mammals, and other aquatic life. The most significant effects of these withdrawals are on early life stages of fish and shellfish through impingement (being pinned against intake screens or other parts at the facility) and entrainment (being drawn into cooling water systems).

On August 17, 2014 (79 FR 48300), EPA published final standards under the CWA for all existing power generating facilities and existing manufacturing and industrial facilities that withdraw more than 2 million gallons of water per day from waters of the United States and use at least 25 percent of that water exclusively for cooling purposes. This rule covers roughly 544 power plants. The national requirements, which will be implemented through NPDES permits, are applicable to the location, design, construction, and capacity of cooling water intake structures at these facilities and are based on the best technology available for minimizing environmental impact. The rule establishes a baseline level of protection and then allows additional safeguards for aquatic life to be developed through site-specific analysis.

6. CCR Final Rule

CCRs are residuals from the combustion of coal in steam electric power plants and include materials such as coal ash (fly ash and bottom ash) and FGD wastes.

On April 17, 2015, EPA finalized national regulations to require the safe disposal of CCRs from coal-fired power plants. The final rule is the culmination of extensive study on the effects of coal ash on the environment and public health. The rule establishes technical requirements for CCR landfills and surface impoundments under Subtitle D of the Resource Conservation and Recovery Act (RCRA), the nation's primary law for regulating solid waste.

These regulations address the risks from coal ash disposal – contaminants leaking into ground water or blowing into the air as dust, and the catastrophic failure of coal ash surface impoundments. Additionally, the rule establishes recordkeeping and reporting requirements as well as the requirement for each facility to post specific information to a publicly accessible website. This final rule also supports the responsible recycling of CCRs by distinguishing safe, beneficial use from disposal.

More specifically, the CCR rule includes groundwater protection requiring the owners or operators of a CCR management unit (*i.e.*, landfill or surface impoundment) to install monitoring wells and procedures for sampling those wells to detect the presence of hazardous constitutes. If contamination is found, the rule includes requirements related to corrective action and/or closure. The final rule also establishes location restrictions to help ensure that CCR landfills and surface impoundments are appropriately sited and liner design criteria for all new landfills, new surface impoundments, and lateral expansions.

The CCR rule also addresses the day-to-day operations of CCR management units and includes requirements to prevent public health and environmental impacts from these management units. These include air criteria to address pollution caused by windblown dust from CCR management units, run-on and run-off controls for landfills, controls related to water discharges and the creation of landfill leachate, and run-off controls to help protect against releases to surface waters.

To reduce the risk of catastrophic failure from coal ash surface impoundments, the CCR rule includes structural integrity design criteria and requires that owners and operators periodically conduct structural integrity-related assessments. Certain surface impoundments must develop an emergency action plan that details actions to take to protect communities if there is an issue with the structural safety of the management unit.

SECTION 2 SUMMARY OF THE FINAL RULE

This section presents a brief summary of the final rule. Section 2.1 summarizes the discharge requirements and Section 2.2 describes the applicability provision and specialized definitions.

2.1 SUMMARY OF DISCHARGE REQUIREMENTS

Steam electric power plants[1] discharge large wastewater volumes, containing vast quantities of pollutants, into waters of the United States. The pollutants include both toxic and bioaccumulative pollutants such as arsenic, mercury, selenium, chromium, and cadmium. Today, these discharges account for about 30 percent of all toxic pollutants discharged into surface waters by all industrial categories regulated under the CWA.[2] The electric power industry has made great strides to reduce air pollutant emissions under Clean Air Act programs. Yet many of these pollutants are transferred to the wastewater as plants employ technologies to reduce air pollution. The pollutants in steam electric power plant wastewater discharges present a serious public health concern and cause severe ecological damage, as demonstrated by numerous documented impacts, scientific modeling, and other studies. When toxic metals such as mercury, arsenic, lead, and selenium accumulate in fish or contaminate drinking water, they can cause adverse effects in people who consume the fish or water. These effects can include cancer, cardiovascular disease, neurological disorders, kidney and liver damage, and lowered IQs in children.

There are, however, affordable technologies that are widely available, and already in place at some plants, which are capable of reducing or eliminating steam electric power plant discharges. In the several decades since the steam electric ELGs were last revised, these technologies have increasingly been used at plants. This final rule is the first to ensure that plants in the steam electric industry employ technologies designed to reduce discharges of toxic metals and other harmful pollutants discharged in the plants' largest sources of wastewater.

The steam electric ELGs that EPA promulgated and revised in 1974, 1977, and 1982 are out of date. They do not adequately control pollutants (toxic metals and other) discharged by this industry, nor do they reflect relevant process and technology advances that have occurred in the last 30-plus years. The rise of new processes for generating electric power (*e.g.* coal gasification) and the widespread implementation of air pollution controls (*e.g.*, flue gas desulfurization (FGD) and flue gas mercury controls (FGMC)) have altered existing wastestreams and created new types of wastewater at many steam electric power plants, particularly coal-fired plants. The

[1] Steam electric power plants covered by the ELGs use nuclear or fossil fuels such as coal, oil, and natural gas to heat water in boilers, which generate steam. This rule does not apply to plants that use non-fossil fuel or non-nuclear fuel or other energy sources, such as biomass or solar thermal energy. The steam is used to drive turbines connected to electric generators. The plants generate wastewater composed of chemical pollutants and thermal pollution (heated water) from their wastewater treatment, power cycle, ash handling, and air pollution control systems, as well as from coal piles, yard and floor drainage, and other plant processes.

[2] Although the way electricity is generated in this country is changing, EPA projects that, without this final rule, steam electric power plant discharges would likely continue to account, over the foreseeable future, for about thirty percent of all toxic pollutants discharged into surface waters by all industrial categories regulated under the CWA.

processes employed and pollutants discharged by the industry look very different today than they did in 1982. Many plants, nonetheless, still treat their wastewater using only surface impoundments, which are largely ineffective at controlling discharges of toxic pollutants and nutrients.

To further its ultimate objective to "restore and maintain the chemical, physical, and biological integrity of the Nation's waters," the CWA authorizes EPA to establish national technology-based effluent limitations guidelines and new source performance standards for discharges from categories of point sources that occur directly into waters of the U.S. The CWA also authorizes EPA to promulgate nationally applicable pretreatment standards that control pollutant discharges from existing and new sources that discharge wastewater indirectly to waters of the U.S. through sewers flowing to publicly owned treatment works (POTWs). EPA establishes ELGs based on the performance of well-designed and well-operated control and treatment technologies.

EPA completed a study of the steam electric category in 2009 and proposed the ELG rule in June 2013. The public comment period extended for more than three months. This final rule reflects the statutory factors outlined in the CWA, as well as EPA's full consideration of the comments received and updated analytical results.

EPA's final rule revises the steam electric ELGs, as they apply to a subset of power plants that discharge wastestreams containing harmful pollutants. EPA is establishing new requirements for best available technology economically achievable (BAT), new source performance standards (NSPS), pretreatment standards for existing sources (PSES), and pretreatment standards for new sources (PSNS) for certain wastestreams, described below, for the Steam Electric ELGs. EPA is not proposing new best conventional pollutant control technology (BCT) nor new best practicable control technology (BPT) requirements as part of the final rule. Section 8 describes the technology options considered for each wastestream as the basis for the regulations, as well as the combination of technology options/wastestreams that included in the regulatory options considered for the rulemaking. As described in Section 8, EPA identified six options for regulating existing discharges (*i.e.*, BAT and PSES requirements) for the revisions to the ELGs. EPA identified one option for regulating discharges from new sources (*i.e.*, NSPS and PSNS requirements). The final rule requirements are summarized below.

2.1.1 Discharges Directly to Surface Water from Existing Sources

For existing sources that discharge directly to surface water, with the exception of oil-fired generating units and small generating units (those with a nameplate capacity of 50 megawatts (MW) or less), the final rule establishes effluent limitations based on BAT. BAT is based on technological availability, economic achievability, and other statutory factors and is intended to reflect the highest performance in the industry (see Section 8.3). The final rule establishes BAT limitations as follows: [3]

- For fly ash transport water, bottom ash transport water, and FGMC wastewater, there are two sets of BAT limitations. The first set of BAT limitations is a numeric effluent

[3] For details on when the following BAT limitations apply, see Section 8.3.

limitation on Total Suspended Solids (TSS) in the discharge of these wastewaters (these limitations are equal to the TSS limitations in the previously established BPT regulations). The second set of BAT limitations is a zero discharge limitation for all pollutants in these wastewaters.[4]

- For FGD wastewater, there are two sets of BAT limitations. The first set of limitations is a numeric effluent limitation on TSS in the discharge of FGD wastewater (these limitations are equal to the TSS limitations in the previously established BPT regulations). The second set of BAT limitations is numeric effluent limitations on mercury, arsenic, selenium, and nitrate/nitrite as N in the discharge of FGD wastewater.[5]
- For gasification wastewater, there are two sets of BAT limitations. The first set of limitations is a numeric effluent limitation on TSS in the discharge of gasification wastewater (this limitation is equal to the TSS limitation in the previously established BPT regulations). The second set of BAT limitations is numeric effluent limitations on mercury, arsenic, selenium, and total dissolved solids (TDS) in the discharge of gasification wastewater.
- A numeric effluent limitation on TSS in the discharge of combustion residual leachate from landfills and surface impoundments. This limitation is equal to the TSS limitation in the previously established BPT regulations.

For oil-fired generating units and small generating units (50 MW or smaller), the final rule establishes BAT limitations on TSS in the discharge of fly ash transport water, bottom ash transport water, FGMC wastewater, FGD wastewater, and gasification wastewater. These limitations are equal to the TSS limitations in the existing BPT regulations.

2.1.2 Discharges Directly to Surface Water from New Sources

The CWA mandates that NSPS reflect the greatest degree of effluent reduction that is achievable, including, where practicable, a standard permitting no discharge of pollutants (see Section 8.4). NSPS represent the most stringent controls attainable, taking into consideration the cost of achieving the effluent reduction and any non-water quality environmental impacts and energy requirements. For direct discharges to surface waters from new sources, including discharges from oil-fired generating units and small generating units, the final rule establishes NSPS as follows:

- A zero discharge standard for all pollutants in fly ash transport water, bottom ash transport water, and FGMC wastewater.
- Numeric standards on mercury, arsenic, selenium, and TDS in the discharge of FGD wastewater.

[4] When fly ash transport water or bottom ash transport water is used in the FGD scrubber, the applicable limitations are those established for FGD wastewater on mercury, arsenic, selenium and nitrate/nitrite as N.

[5] For plants that opt into the voluntary incentives program, the second set of BAT limitations is numeric effluent limitations on mercury, arsenic, selenium, and TDS in the discharge of FGD wastewater.

- Numeric standards on mercury and arsenic in the discharge of combustion residual leachate.

2.1.3 Discharges to POTWs from Existing Sources

PSES are designed to prevent the discharge of pollutants that pass through, interfere with, or are otherwise incompatible with the operation of POTWs. PSES are analogous BAT effluent limitations for direct dischargers and are generally based on the same factors (see Section 8.5). The final rule establishes PSES as follows:[6]

- A zero discharge standard for all pollutants in fly ash transport water, bottom ash transport water, and FGMC wastewater.[7]
- Numeric standards on mercury, arsenic, selenium, and nitrate/nitrite as N in the discharge of FGD wastewater.
- Numeric standards on mercury, arsenic, selenium and TDS in the discharge of gasification wastewater.

2.1.4 Discharges to POTWs from New Sources

PSNS are also designed to prevent the discharge of any pollutant into a POTW that interferes with, passes through, or is otherwise incompatible with the POTW. PSNS are analogous to NSPS for direct dischargers, and EPA generally considers the same factors for both sets of standards (see Section 8.6). The final rule establishes PSNS that are the same as the rule's NSPS.

2.2 Revisions to Applicability Provision and Specialized Definitions

In addition to the discharge requirements described in Section 2.1, the final rule modifies the applicability provision for the ELGs. These modifications would not alter which generating units are regulated by the ELGs. These units have been traditionally regulated by the existing ELGs. Instead, the modifications would remove potential ambiguity present in the preexisting regulatory text. The changes include:

- Clarification that certain plants, such as certain municipally-owned plants, which generate and distribute electricity within a service area (such as distributing electric power to municipally-owned buildings), but which use accounting practices that are not commonly thought of as a "sale," are nevertheless subject to the ELGs.
- Clarification that "primarily," as used in 40 CFR Part 423.10, refers to those operations where the generation of electricity is the predominant source of revenue and/or principal reason for operation.
- Clarification that fuels derived from fossil fuel are within the scope of the current ELGs.

[6] For details on when PSES apply, see Section 8.5.

[7] When fly ash transport water or bottom ash transport water is used in the FGD scrubber, the applicable standards are those established for FGD wastewater on mercury, arsenic, selenium and nitrate/nitrite as N.

- Clarification that combined cycle systems, which are generating units comprising one or more combustion turbines operating in conjunction with one or more steam turbines, are subject to the ELGs.

In addition to the revisions discussed above, the final rule revises certain existing specialized definitions, as well as includes new specialized definitions. The revisions to existing specialized definitions (with revisions underlined) are:

> (b) The term *low volume waste sources* means, taken collectively as if from one source, wastewater from all sources except those for which specific limitations or standards are otherwise established in this part. Low volume waste~~s~~ sources include, but are not limited to, the following: ~~wastewaters from wet scrubber air pollution control systems,~~ wastewaters from ion exchange water treatment systems, water treatment evaporator blowdown, laboratory and sampling streams, boiler blowdown, floor drains, cooling tower basin cleaning wastes, ~~and~~ recirculating house service water systems, and wet scrubber air pollution control systems whose primary purpose is particulate removal. Sanitary ~~and~~ wastes, air conditioning wastes, and wastewater from carbon capture or sequestration systems are not included in this definition.
>
> (e) The term *fly ash* means the ash that is carried out of the furnace by the gas stream and collected by a capture device such as a mechanical precipitator~~s~~, electrostatic precipitator~~s~~, and/or fabric filter~~s~~. Economizer ash is included in this definition when it is collected with fly ash. Ash is not included in this definition when it is collected in wet scrubber air pollution control systems whose primary purpose is particulate removal.
>
> (f)The term *bottom ash* means the ash, including boiler slag, which settles in the furnace or is dislodged from furnace walls ~~that drops out of the furnace gas stream in the furnace and in the economizer sections~~. Economizer ash is included when it is collected with bottom ash.

New specialized definitions are:

> (n) The term *flue gas desulfurization (FGD) wastewater* means wastewater generated specifically from the wet flue gas desulfurization scrubber system that comes into contact with the flue gas or the FGD solids, including but not limited to, the blowdown or purge from the FGD scrubber system, overflow or underflow from the solids separation process, FGD solids wash water, and the filtrate from the solids dewatering process. Wastewater generated from cleaning the FGD scrubber, cleaning FGD solids separation equipment, cleaning FGD solids dewatering equipment, or that is collected in floor drains in the FGD process area is not considered FGD wastewater.
>
> (o) The term *flue gas mercury control (FGMC) wastewater* means wastewater generated from an air pollution control system installed or operated for the purpose of removing mercury from flue gas. This includes fly ash collection systems when the particulate control system follows sorbent injection or other controls to remove

mercury from flue gas. FGD wastewater generated at plants using oxidizing agents to remove mercury in the FGD system and not in a separate FGMC system is not included in this definition.

(p) The term *transport water* means wastewater that is used to convey fly ash, bottom ash, or economizer ash from the ash collection or storage equipment, or boiler, and has direct contact with the ash. Transport water does not include low volume, short duration discharges of wastewater from minor leaks (e.g., leaks from valve packing, pipe flanges, or piping) or minor maintenance events (e.g., replacement of valves or pipe sections).

(q) The term *gasification wastewater* means any wastewater generated at an integrated gasification combined cycle operation from the gasifier or the syngas cleaning, combustion, and cooling processes. Gasification wastewater includes, but is not limited to the following: sour/grey water; CO_2/steam stripper wastewater; sulfur recovery unit blowdown, and wastewater resulting from slag handling or fly ash handling, particulate removal, halogen removal, or trace organic removal. Air separation unit blowdown, noncontact cooling water, and runoff from fuel and/or byproduct piles are not considered gasification wastewater. Wastewater that is collected intermittently in floor drains in the gasification process area from leaks, spills and cleaning occurring during normal operation of the gasification operation is not considered gasification wastewater.

(r) The term *combustion residual leachate* means leachate from landfills or surface impoundments containing combustion residuals. Leachate is composed of liquid, including any suspended or dissolved constituents in the liquid, that has percolated through waste or other materials emplaced in a landfill, or that passes through the surface impoundment's containment structure (*e.g.*, bottom, dikes, berms). Combustion residual leachate includes seepage and/or leakage from a combustion residual landfill or impoundment unit. Combustion residual leachate includes wastewater from landfills and surface impoundments located on non-adjoining property when under the operational control of the permitted facility.

(s) The term *oil-fired unit* means a generating unit that uses oil as the primary or secondary fuel source and does not use a gasification process or any coal or petroleum coke as a fuel source. This definition does not include units that use oil only for start up or flame-stabilization purposes.

(t) The phrase "as soon as possible" means November 1, 2018, unless the permitting authority establishes a later date, after receiving information from the discharger, which reflects a consideration of the following factors:

(1) Time to expeditiously plan (including to raise capital), design, procure, and install equipment to comply with the requirements of this part.

(2) Changes being made or planned at the plant in response to (i) new source performance standards for greenhouse gases from new fossil fuel-fired electric

generating units, under sections 111, 301, 302, and 307(d)(1)(C) of the Clean Air Act, as amended, 42 U.S.C. 7411, 7601, 7602, 7607(d)(1)(C); (ii) emission guidelines for greenhouse gases from existing fossil fuel-fired electric generating units, under sections 111, 301, 302, and 307(d) of the Clean Air Act, as amended, 42 U.S.C. 7411, 7601, 7602, 7607(d); or (iii) regulations that address the disposal of coal combustion residuals as solid waste, under sections 1006(b), 1008(a), 2002(a), 3001, 4004, and 4005(a) of the Solid Waste Disposal Act of 1970, as amended by the Resource Conservation and Recovery Act of 1976, as amended by the Hazardous and Solid Waste Amendments of 1984, 42 U.S.C. 6906(b), 6907(a), 6912(a), 6944, and 6945(a).

(3) For FGD wastewater requirements only, an initial commissioning period for the treatment system to optimize the installed equipment.

(4) Other factors as appropriate.

As stated in the new specialized definition for ash transport water, transport water does not include low volume, short duration discharges of wastewater from minor maintenance events. Examples of minor maintenance events include, but are not limited to, the following:

- Sluice line isolation/crossover valve packing failure or other mechanical valve failure.
- Minor leaks due to corrosion/erosion in the closed-loop system pumps, piping, valves, connections, and tanks.
- Minor leaks due to packing or seal failures in pumps, ash crushers, and bottom ash hopper isolation gates.

EPA does not consider any activity that requires draining the majority of the water volume from a wet sluicing, closed-loop system containment vessel (e.g., bottom ash hopper, remote MDS, dewatering bin, settling tank, surge tank) a minor maintenance event. Examples of maintenance events that are not included in EPA's definition of "minor maintenance" include, but are not limited to, the following:

- Bottom ash hopper refractory or steel hopper plate replacement.
- Bottom ash hopper enclosure replacement or sluice door maintenance.
- Remote mechanical drag system (MDS) wear plate or steel hopper plate replacement.
- Closed-loop system surge tank plate steel replacement or maintenance.
- MDS mechanical failure (e.g., chain derailment), wear plate replacement, or steel hopper plate replacement or maintenance.

SECTION 3
DATA COLLECTION ACTIVITIES

EPA collected and evaluated information from various sources in the course of developing the effluent limitations guidelines and standards (ELGs) for the Steam Electric Power Generating Point Source Category (Steam Electric Category). EPA used these data to develop the industry profile, determine the plant population affected by the rule, evaluate industry subcategorization, identify plant-specific operations, and determine wastewater characteristics, technology options, compliance costs, baseline pollutant loadings, post-compliance pollutant reductions, and non-water quality environmental impacts. This section discusses the following data collection activities as they relate to technical aspects of this rulemaking:

- Steam Electric Power Generating Detailed Study (Section 3.1).
- *Questionnaire for the Steam Electric Power Generating Effluent Guidelines* (Section 3.2).
- Site visits (Section 3.3).
- Field sampling program (Section 3.4).
- EPA and state sources (Section 3.5).
- Industry-submitted data (Section 3.6).
- Technology vendor data (Section 3.7).
- Other data sources (Section 3.8).
- Protection of confidential business information (Section 3.9).

3.1 STEAM ELECTRIC POWER GENERATING DETAILED STUDY

EPA conducted a detailed study of the steam electric power generating industry between 2005 and 2009. During the study, EPA collected data about the industry by performing the following activities:

- Conducted 34 site visits and six wastewater sampling episodes at steam electric power plants.
- Distributed a questionnaire to collect data from nine companies (operating 30 coal-fired power plants).
- Reviewed publicly available sources of data.
- Coordinated with EPA program offices, other government organizations (*e.g.*, state groups and permitting authorities), and industry and other stakeholders.

EPA's *Steam Electric Power Generating Point Source Category: Detailed Study Report* describes the steam electric power generating industry and its wastewater discharges and the data collection activities and analyses conducted during EPA's detailed study [U.S. EPA, 2009a]. The study focused largely on discharges associated with coal ash handling operations and wastewater from flue gas desulfurization (FGD) air pollution control systems because these sources are responsible for the majority of the toxic pollutants discharged by steam electric power plants.

EPA also evaluated wastewater from coal pile runoff, condenser cooling, equipment cleaning, and leachate from landfills and surface impoundments. Additionally, EPA reviewed information on integrated gasification combined cycle (IGCC) operations and carbon capture technologies. EPA also identified wastewaters from flue gas mercury control (FGMC) systems and regeneration of the catalysts used for selective catalytic reduction (SCR) NOx controls as potential new wastestreams that warrant attention.

EPA used the information collected during the detailed study to select plants with different technology bases for site visits, support the development of the *Questionnaire for the Steam Electric Power Generating Effluent Guidelines*, select plants to receive the survey, and select plants for EPA's sampling program during the rulemaking. Additionally, EPA used the data collected during the detailed study to develop an industry profile and supplement the findings from the survey and sampling program (*i.e.*, Form 2C permit application data provided by an industry trade association). The remainder of Section 3 provides additional details regarding the data used from the study.

3.2 QUESTIONNAIRE FOR THE STEAM ELECTRIC POWER GENERATING EFFLUENT GUIDELINES

The principal source of information and data used in developing the ELGs are the responses provided by industry to the survey distributed by EPA under the authority of section 308 of the Clean Water Act (CWA), 33 U.S.C. 1318. EPA designed the industry survey to obtain technical information related to wastewater generation and treatment, and economic information such as costs of wastewater treatment technologies and financial characteristics of potentially affected companies. The Agency used the responses to evaluate pollution control options for establishing revisions to the ELGs for the Steam Electric Category.

EPA developed an Information Collection Request (ICR) entitled *Questionnaire for the Steam Electric Power Generating Effluent Guidelines* (Steam Electric Survey) [U.S. EPA, 2010]. The survey, approved by the Office of Management and Budget (OMB) in May 2010 (OMB Control No. 2040-0281), comprises the following nine parts:

- Part A: Steam Electric Power Plant Operations.
- Part B: FGD Systems.
- Part C: Ash Handling.
- Part D: Pond/Impoundment Systems and Other Wastewater Treatment Operations.
- Part E: Wastes from Cleaning Metal Process Equipment.
- Part F: Management Practices for Ponds/Impoundments and Landfills.
- Part G: Leachate Sampling Data for Ponds/Impoundments and Landfills.
- Part H: Nuclear Power Generation.
- Part I: Economic and Financial Data.

Part A gathered information on all steam electric generating units at the surveyed plant, the fuels used to generate electricity, air pollution controls, cooling water, ponds/impoundments and landfills used for coal combustion residuals (CCR), coal storage and processing, and outfalls. Parts B through H collected detailed technical information on certain aspects of power plant operations, including requiring some plants to collect and analyze wastewater samples, while Part I collected economic data.

To identify the population of steam electric power plants that would be candidates to receive the survey, EPA first created a sample frame consisting of all fossil- and nuclear-fueled steam electric power plants in the United States that reported operating under North American Industry Classification System (NAICS) code 22, and their corresponding generating units. NAICS code 22 (Utilities) comprises establishments engaged in providing the following utility services: electric power, natural gas, steam supply, water supply, and sewage removal. Because power generation was not the primary purpose of some of the plants in this NAICS code (*i.e.*, sewage removal plants), EPA removed them from the sample frame.

The resulting sample frame consisted of information obtained from databases that are maintained by the Energy Information Administration (EIA), a statistical agency of the U.S. Department of Energy (DOE) that collects information on existing electric generating plants and associated equipment to evaluate the current status and potential trends in the industry. The source of the information gathered was primarily the 2007 Electric Generator Report (Form EIA-860) and it was supplemented by information collected by the 2007 Power Plant Operations Report (Form EIA-923) and a survey conducted by EPA's Office of Solid Waste and Emergency Response (OSWER) [U.S. EPA, 2009b]. In addition, EPA identified two plants that started operations after 2007 and obtained information about them from Internet searches.

Collectively, the data sources provided key information for each steam electric power plant with a NAICS code of 22, such as county, state, North American Electric Reliability Council (NERC) region, business size (small or non-small), and regulatory status (*e.g.*, regulated by public service commission). Also included in the data sources were the number of each type of generating unit operated at the plant and the type of fuel used by each generating unit. In addition, the OSWER survey results and the EIA-923 data set provided information on the presence of surface impoundments and landfills at the plant along with the materials the plant stored or disposed of in the impoundment/landfill. EPA also used data for steam electric generating units reported in the EIA-860 data set, such as prime mover and fuel (fossil or nuclear), nameplate capacity (in megawatts (MW)), unit fuel classification, and the plant where the generating unit is housed. The sample frame contained information on 1,197 plants containing 2,571 generating units that were potentially within the scope of the Steam Electric ELGs.

To minimize the burden on the respondents, EPA grouped plants based on the type(s) of fuel they use so that an efficient stratified sampling scheme could be applied.[8] This sampling strategy allowed for different sampling rates across the strata. Depending on the amount or type of information it needed for the rulemaking, EPA solicited information either from all plants within a stratum (*i.e.*, a census or "certainty" stratum) or from a random sample of plants within

[8] EPA classified plants into fuel categories to develop the sample frame of all fossil- and nuclear-fueled steam electric power plants in the United States. EPA further developed plant-level fuel classifications based on a hierarchy of the type of units operating at the plant; therefore, some plants may operate units that burn other types of fuel in addition to the fuel under which they are classified. Plants that operated coal- or petroleum coke-fired units were classified as coal or petroleum coke regardless of other fuels at the plant. For example, a plant classified as coal will have coal-fired unit(s) at the plant, but may also have an oil- fired, gas-fired, or nuclear unit(s).

a stratum (*i.e.*, probability sampled stratum). As a result, the survey was distributed to all coal- and petroleum coke-fired power plants and a sample of the rest of the steam electric power generating industry, including oil-fired, gas-fired, gas-combined cycle, and nuclear power plants. Table 3-1 presents the number of plants in each fuel classification (*i.e.*, stratum) for the sample frame used to identify survey recipients.

Table 3-1. Number of Plants in Each Fuel Classification in the Survey Sample Frame Used to Identify Survey Recipients

Fuel Classification	Number of Facilities
Coal	495
Petroleum coke	9
Oil	43
Gas	555
Nuclear	63
Combination [a]	32

a – EPA used the "combination" designation for plants that have at least two generating units that have different unit-level designations (*e.g.*, oil, gas, nuclear), but do not have any coal or petroleum coke units.

The survey comprised several sections that were tailored to address specific processes, data needs, or types of power plants. EPA sent Parts A and I of the survey to all sampled plants and the remaining sections to sampled plants according to their fuel classification. Specifically, in addition to Parts A and I, all coal- and petroleum coke-fired power plants received Parts B, C, D, and H. A subsample of coal- and petroleum coke-fired power plants also received Parts E, F, and G. The sampled plants in the oil-fired and combination strata received Parts A, B, C, D, E, H, and I.[9] The sampled plants in the gas-fired, gas-combined cycle, and nuclear power strata received Parts A, E, H, and I.

Most parts of the survey focused on gathering information from all coal- and petroleum coke-fired power plants. Therefore, all plants with a fuel classification of coal or petroleum coke were selected with certainty (*i.e.*, probability of selection equal to one) to receive Parts A, B, C, D, E, H, and I. In addition, for strata with 10 or fewer plants, EPA included all plants in the sample, and at least 10 plants were sampled within strata containing more than 10 plants. As such, all regulated and nonregulated combination plants (except gas-fired and gas-combined cycle) were selected with certainty. For the remaining nonregulated and regulated plants with plant fuel classifications of gas, gas-combined cycle, oil, nuclear, and combination (gas and gas-combined cycle), EPA randomly selected 30 percent of the plants to receive the survey while adhering to the 10 plant minimum per stratum. Based on this sampling design, 733 plants from the survey sample frame presented on Table 3-1 were selected to receive the survey. This total includes 495 coal-fired, nine petroleum coke-fired, 20 oil-fired, 167 gas-fired, 20 nuclear power plants, and 22 combination power plants.

[9] For the purpose of the survey, combination power plants mean plants that do not operate generating units fueled by coal or petroleum coke and have at least two generating units that have different unit-level fuel classifications (*e.g.*, gas and oil, gas and gas-combined cycle).

EPA distributed and received 733 completed surveys, including those from 53 plants that certified that they were not and did not have the capability to be engaged in steam electric power generation, would be retired by December 31, 2011, or did not generate electricity in 2009 by burning any fossil or nuclear fuels.[10] Because responses were received for all 733 sampled plants (including those 53 plants that were not required to complete the remainder of the survey), no plants were considered non-respondents and the response rate was 100 percent.

EPA then developed weighting factors to represent the entire industry on a national level from the data provided by the 733 plants that received the survey. Because it selected coal- and petroleum coke-fired plants with certainty, EPA did not weight the responses for the majority of data because all plants were represented. However, because EPA sent only Parts E, F, and G of the survey to a probability sample of coal- and petroleum coke-fired plants, the Agency weighted the data from these parts to represent the entire industry. In addition, EPA weighted data collected from the probability-sampled strata for other fuel types to represent the entire industry. All survey data presented in this document have been weighted to represent the entire industry, unless otherwise noted.

3.3 SITE VISITS

EPA conducted a site visit program to gather information on the types of wastewaters generated by steam electric power plants and the methods of managing these wastewaters to allow for recycle, reuse, or discharge. For most site visits, EPA focused data gathering activities primarily on FGD wastewater treatment and management of ash transport water at coal- and petroleum coke-fired power plants because the FGD and ash transport water streams are the primary sources of pollutant discharges from the industry. EPA also conducted site visits at oil-, gas-, and nuclear-fueled power plants to better understand the plant operations, the wastewaters generated, and the types of treatment systems used. EPA conducted 73 site visits at steam electric power plants in 18 states between December 2006 and November 2014. The Agency conducted three additional site visits in Italy in April 2011 to obtain information on their FGD wastewater treatment systems. Table 3-2 summarizes the site visits conducted. The list of site visits excludes EPA sampling episodes and EPA audits of CWA 308 sampling described in Section 3.4.

The purpose of the site visits was to collect information about each site's electric generating processes, wastewater management practices, and treatment technologies, and to evaluate each plant for potential inclusion in EPA's sampling program. EPA used information gathered from EPA's Office of Air and Radiation (OAR), EIA, the Utility Water Act Group (UWAG), and other sources, including publicly available plant-specific information, state and regional permitting authorities, the Study data request, and the Steam Electric Survey, to identify plant operations of interest. EPA made pre-site visit phone calls to confirm plant characteristics and to select plants for site visits. The specific objectives of these site visits were to:

- Gather general information about each plant's operations.
- Gather information on pollution prevention and wastewater treatment/operations.

[10] At the time EPA developed the survey, it used 2011 as the cutoff year for retirements because the plants would be retired before the proposed rule was published.

- Evaluate whether the plant was appropriate to include in the sampling program.
- Gather plant-specific information to develop sampling plans.
- Select and evaluate potential sampling points.

Table 3-2. List of Site Visits Conducted During the Detailed Study and Rulemaking

Plant Name, Location	Month/Year of Site Visit
Yates, *Georgia*	Dec 2006
Wansley, *Georgia*	Dec 2006
Widows Creek, *Alabama*	Dec 2006; Sept 2007
Conemaugh, *Pennsylvania*	Feb 2007; Aug 2012
Homer City, *Pennsylvania*	Feb 2007; Aug 2007; Aug 2012
Pleasant Prairie, *Wisconsin*	Apr 2007; Mar 2010
Bailly, *Indiana*	Apr 2007
Seminole, *Florida*	Apr 2007; Jan 2013
Big Bend, *Florida*	Apr 2007; Jul 2007
Cayuga, *New York*	May 2007
Mitchell, *West Virginia*	May 2007; Oct 2007
Cardinal, *Ohio*	May 2007; Oct 2007; Feb 2010
Bruce Mansfield, *Pennsylvania*	Oct 2007
Roxboro, *North Carolina*	Mar 2008
Belews Creek, *North Carolina*	Mar 2008; Oct 2008
Marshall, *North Carolina*	Mar 2008
Mount Storm, *West Virginia*	Sept 2008
Harrison, *West Virginia*	Sept 2008
Mountaineer, *West Virginia*	Sept 2008; Jan 2009
Gavin, *Ohio*	Sept 2008
Deely, *Texas*	Oct 2008
Clover, *Virginia*	Oct 2008
JK Spruce, *Texas*	Oct 2008
Fayette Power Project/Sam Seymour, *Texas*	Oct 2008
Ghent, *Kentucky*	Dec 2008
Trimble County, *Kentucky*	Dec 2008
Cane Run, *Kentucky*	Dec 2008
Mill Creek, *Kentucky*	Dec 2008
Brandon Shores, *Maryland*	Jan 2009; Mar 2010
Kenneth C Coleman, *Kentucky*	Feb 2009
Gibson, *Indiana*	Feb 2009
Paradise, *Kentucky*	Feb 2009
Wabash River, *Indiana*	Feb 2009; Aug 2010
Miami Fort, *Ohio*	Apr 2009; Mar 2010
Covanta, *Virginia*	Jul 2009

Table 3-2. List of Site Visits Conducted During the Detailed Study and Rulemaking

Plant Name, Location	Month/Year of Site Visit
Chesterfield, *Virginia*	Sept 2009
Karn-Weadock, *Michigan*	Sept 2009
Kinder Morgan Power, *Michigan*	Sept 2009
Monroe, *Michigan*	Sept 2009
Allen, *North Carolina*	Oct 2009
Cape Fear, *North Carolina*	Oct 2009
Catawba, *South Carolina*	Oct 2009
HB Robinson, *South Carolina*	Oct 2009
FP&L Sanford, *Florida*	Oct 2009
Polk, *Florida*	Oct 2009
Fort Martin, *West Virginia*	Feb 2010
Hatfield's Ferry, *Pennsylvania*	Feb 2010
Keystone, *Pennsylvania*	Feb 2010
Dickerson, *Maryland*	Mar 2010
Dallman, *Illinois*	Apr 2010
Duck Creek, *Illinois*	Apr 2010
Iatan, *Missouri*	Apr 2010
Edwardsport, *Indiana*	Mar 2011
Torrevaldaliga Nord, *Italy*	Apr 2011
Monfalcone, *Italy*	Apr 2011
Frederico II (Brindisi), *Italy*	Apr 2011
FP&L Manatee, *Florida*	Nov 2011
Wateree, *South Carolina*	Jan 2013
McMeekin, *South Carolina*	Jan 2013
JEA Northside, *Florida*	Apr 2014
John E. Amos, *West Virginia*	Nov 2014

3.4 FIELD SAMPLING PROGRAM

Between July 2007 and April 2011, EPA conducted a sampling program at 17 different steam electric power plants in the United States and Italy to collect wastewater characterization data and treatment performance data associated with FGD wastewater, fly ash and bottom ash transport water, and wastewater from gasification and carbon capture processes. EPA also obtained sampling data for surface impoundment and landfill leachate collection and treatment systems at 39 plants, as required by Part G of the Steam Electric Survey. This leachate sampling is not included in the following description of the field sampling program.

EPA's field sampling program began during its detailed study and continued throughout this rulemaking effort. During the study, EPA conducted 1- or 2-day sampling episodes at six plants to characterize untreated wastewaters generated by coal-fired power plants, as well as assess treatment technologies and best management practices for reducing pollutant discharges.

The types of wastewaters sampled during the detailed study were untreated and treated FGD wastewater, fly ash transport water, and bottom ash transport water. See the *Steam Electric Power Generating Point Source Category: Final Detailed Study Report* for additional information on the sampling program completed during the detailed study [U.S. EPA, 2009a].

After completing the detailed study, EPA conducted a sampling program at steam electric power plants to collect wastewater characterization data and treatment performance data associated with FGD wastewater and to collect data for other emerging wastestreams for which characterization data were not available (*i.e.*, carbon capture and gasification wastewaters). As part of this sampling program, EPA conducted on-site sampling activities (*i.e.*, samples were collected directly by EPA) and also required some plants to collect samples for EPA (*i.e.*, CWA 308 monitoring program). The following sections present information on the selection of plants sampled, the wastewater treatment systems sampled, and the process for field sampling conducted following the completion of the detailed study.

3.4.1 <u>On-Site Sampling Activities</u>

As part of EPA's field sampling program, EPA conducted sampling episodes at steam electric power plants in the United States and Italy to collect wastewater characterization and wastewater treatment technology performance data.

3.4.1.1 United States

EPA conducted 4-day sampling episodes at seven U.S. plants to obtain the following: 1) wastewater characterization data and 2) wastewater treatment technology performance data. EPA used these data in combination with other industry-supplied data to evaluate wastewater discharges resulting from steam electric power plants and to evaluate technology options for handling and treating these wastewaters. The sampling program primarily focused on the wastewaters associated with operating wet FGD systems. EPA collected information to characterize the untreated FGD scrubber purge wastewater, as well as treated FGD wastewater from chemical precipitation and biological treatment systems.

The sampling characterized the wastewaters generated by wet FGD scrubbers and the treatment performance of the systems used to treat the FGD scrubber purge wastewaters. EPA also collected field quality control (QC) samples consisting of bottle blanks, field blanks, equipment blanks, and duplicate samples, and laboratory QC samples used for matrix spike/matrix spike duplicate analyses.

EPA also collected data regarding system design and day-to-day operation to perform an engineering assessment of the design, operation, and performance of treatment systems at steam electric power plants.

EPA considered the following characteristics to select plants for sampling:

- **Coal-Fired Boilers**: All of the plants selected for the sampling program were coal-fired plants because the wastestreams of interest for the sampling program data objectives are associated with coal-fired power plants.

- **Wet FGD System**: EPA evaluated wastewaters generated from wet FGD systems and the treatment of these wastewaters. EPA considered the following selection criteria regarding FGD systems:
  - *Type of FGD Wastewater Treatment System*: The primary factor for selection was the type of wastewater treatment system being operated to treat FGD wastewater. EPA selected plants operating the following types of wastewater treatment systems, which are the basis for the technology options:
    - Chemical precipitation.
    - Biological treatment.
    - Vapor-compression evaporation.
  - *Age of FGD Wastewater Treatment System:* EPA collected samples from wastewater treatment systems that reached steady-state operation. EPA sampled FGD wastewater treatment systems that had been operating for at least 6 months and that plant staff considered the system to have reached a pseudo steady-state condition past the initial commissioning period.
  - *Type of FGD System*: EPA considered the type of FGD system operated by the plant (*e.g.*, limestone forced oxidation, lime inhibited oxidation) when selecting plants for sampling. Plants generating FGD scrubber wastewater typically operate limestone forced oxidation (LSFO) FGD systems. The LSFO system has the capability of producing wallboard-grade gypsum, but it typically requires a purge stream that needs to be treated prior to discharge.[11]

- **NO_x Controls**: EPA considered whether the plants operate a SCR system or a selective noncatalytic reduction (SNCR) system. Although these NO_x control systems do not generate a specific wastewater stream, EPA considered whether their operation may affect the FGD wastewater characteristics as well as the fly ash and associated fly ash sluice water characteristics.
- **Power Load Cycling**: EPA considered a plant's typical load cycling (*i.e.*, baseload, cycling, peaking). Most of the plants sampled were baseload plants; however, EPA also selected plants with cycling units.
- **Type of Coal:** EPA selected plants burning different types of coal to help assess whether the types and concentration of metals present in the FGD wastewater could differ based on the fuel source. Most of the sampled plants burn bituminous coal because the majority of plants with wet FGD systems burn bituminous coal; however, EPA also sampled wastewater at plants that burn subbituminous coal.

EPA conducted sampling activities at the following U.S. plants:

[11] EPA did not select any plants operating inhibited oxidation FGD systems or once-through FGD systems for sampling after completing the detailed study because EPA did not identify any plants that operate these systems and also operate a chemical precipitation or biological treatment system. The wastewater pollutants present in these systems are similar to those generated by LSFO systems because the scrubbing process captures the same types of pollutants from the flue gas. The technologies used to treat wastewater from a recirculating LSFO FGD system would also be effective at treating the wastewater from inhibited oxidation or once-through LSFO FGD systems.

- Duke Energy Carolina's Belews Creek Steam Station, *North Carolina* [ERG, 2012a].
- We Energies' Pleasant Prairie Power Plant, *Wisconsin* [ERG, 2012b].
- Duke Energy's Miami Fort Station, *Ohio* [ERG, 2012c].
- Duke Energy Carolina's Allen Steam Station, *North Carolina* [ERG, 2012d].
- Mirant Mid-Atlantic, LLC's Dickerson Generating Station, *Maryland* [ERG, 2012e].
- RRI Energy's Keystone Generating Station, *Pennsylvania* [ERG, 2012f].
- Allegheny Energy's Hatfield's Ferry Power Station, *Pennsylvania* [ERG, 2012g].

All of the plants selected for sampling operated chemical precipitation wastewater treatment systems to treat their FGD wastewater. The treatment systems at Belews Creek Steam Station, Allen Steam Station, and Dickerson Generating Station also included a biological treatment stage following the chemical precipitation. Table 3-3 presents the details for each sampled plant.

The pollutants selected for analysis reflected the current understanding of FGD wastewaters, including contributions from the fuel, scrubber sorbents, treatment chemicals, and other sources. Table 3-4 lists the analytical methods that EPA used for each analyte. In addition to these analytes, EPA collected field measurements, including temperature and pH, at all sampling points.

Table 3-3. Selection Criteria for Plants Included in EPA's Sampling Program in the United States

Plant Name	Selection Criteria							
	Coal-Fired Boilers	FGD Treatment System		Type of FGD System	NOx Controls	Power Load Cycling	Type of Coal	Commercial-Grade Gypsum By-Product
		Chemical Precipitation	Biological					
Belews Creek	Yes	Yes[a,c]	Yes[d]	LSFO	SCR	Baseload	Eastern Bituminous	Yes
Pleasant Prairie	Yes	Yes[b]	No	LSFO	SCR	Baseload	Subbituminous	Yes
Miami Fort	Yes	Yes[b]	No	LSFO	SCR	Baseload	Eastern Bituminous	Yes
Allen	Yes	Yes[a,c]	Yes[d]	LSFO	SNCR	Cycling	Bituminous	Yes
Dickerson	Yes	Yes[a,c]	Yes[e]	LSFO	SNCR	Cycling	Eastern Bituminous	Yes
Keystone	Yes	Yes[b]	No	LSFO	SCR	Baseload	Eastern Bituminous	No
Hatfield's Ferry	Yes	Yes[b]	No	LSFO	SNCR	Baseload	Bituminous, Subbituminous	No

a – The chemical precipitation systems at these plants include hydroxide precipitation and iron co-precipitation, but do not include sulfide precipitation as part of the process.

b – The chemical precipitation systems at these plants include hydroxide precipitation, sulfide precipitation, and iron co-precipitation.

c – The chemical precipitation systems at these plants precede a biological treatment stage.

d – The biological treatment systems at these plants include an anoxic/anaerobic biological system primarily designed to remove selenium.

e – The biological treatment system at this plant includes a sequencing batch reactor (SBR) primarily designed for nutrient removal (nitrification/denitrification).

Table 3-4. Analytical Methods Used for EPA's Sampling Program

Parameter	Method Number
Classicals	
Biochemical oxygen demand (BOD_5)	SM 5210 B
Chemical oxygen demand (COD)	EPA 410.4
Total suspended solids (TSS)	SM 2540 D
Total dissolved solids (TDS)	SM 2540 C
Sulfate	EPA 300.0
Chloride	EPA 300.0
Ammonia as nitrogen	EPA 350.1
Nitrate-nitrite as nitrogen	EPA 353.2
Total Kjeldahl nitrogen (TKN)	EPA 351.2
Total phosphorus	EPA 365.1
Total cyanide	SM 4500 CN E
Total and Dissolved Metals	
Mercury	EPA 1631E
Hexavalent chromium (dissolved only)	EPA 218.6
Antimony, arsenic, cadmium, chromium, copper, lead, nickel, selenium, silver, thallium, and vanadium	EPA 200.8 with collision cell
Aluminum, barium, beryllium, boron, calcium, cobalt, iron, magnesium, manganese, molybdenum, sodium, tin, titanium, and zinc [a]	EPA 200.7

a – Zinc was analyzed using EPA Method 200.8 with collision cell for the Belews Creek, Pleasant Prairie, Miami Fort, and Allen sampling episodes, but was analyzed by EPA Method 200.7 for the Dickerson, Keystone, and Hatfield's Ferry sampling episodes. EPA changed methods because the Agency observed high concentrations of zinc in the influent and effluent samples that were more suited for analysis by EPA Method 200.7.

EPA collected representative samples at the influent and effluent of the FGD wastewater treatment systems and, where applicable, the mid-point of the FGD treatment system (*i.e.*, effluent from chemical precipitation system prior to biological treatment). EPA collected 24-hour composite samples at the mid-point and effluent sampling points for all analytes except mercury and cyanide. At the mid-point and effluent sampling points, EPA collected cyanide as a single grab sample and mercury as four individual grab samples over the 24-hour period (*i.e.*, a grab sample collected every six hours). All influent samples were collected as grab samples.

Sampling episode reports describing the sample collection activities and the analytical results from the seven on-site sampling episodes are included in the rulemaking record [ERG, 2012a-2012g].

3.4.1.2 Italy

In April 2011, EPA conducted a 3-day sampling episode at Enel's Federico II Power Plant (Brindisi), located in Brindisi, Italy. The purpose was to characterize untreated FGD scrubber purge and treated FGD wastewater from an FGD wastewater treatment system consisting of chemical precipitation followed by mechanical vapor-compression evaporation. The mechanical vapor-compression evaporation system used a falling-film brine concentrator to produce a concentrated wastewater stream and a reusable distillate stream. The concentrated wastewater stream was further processed in a forced-circulation crystallizer, in which a solid product was generated along with a reusable condensate stream.

In addition to collecting the samples of untreated FGD scrubber purge and treated FGD wastewater, EPA also collected field quality control (QC) samples consisting of bottle blanks, field blanks, equipment blanks, field duplicate samples, and laboratory QC aliquots used for matrix spike/matrix spike duplicate analyses.

EPA selected Brindisi for sampling because it operates a one-stage chemical precipitation system followed by softening and a two-stage vapor-compression evaporation system to treat FGD wastewater. The following are the characteristics of the Brindisi plant:

- The plant is a coal-fired power plant.
- The plant operates LSFO wet FGD systems on all four units.
- The plant operates a segregated FGD wastewater treatment system, which includes the following steps:
  - Settling,
  - Equalization,
  - Lime, sodium sulfide, and caustic soda addition (pH adjustment/metal hydroxide precipitation),
  - Ferric chloride addition,
  - Polyelectrolyte addition,
  - Clarification,
  - Ferrous chloride and soda ash addition (softening),
  - Clarification,
  - Evaporation (brine concentrator),
  - Crystallization.
- The plant operates SCR systems on all four units.

EPA collected samples for the same list of analytes listed in Table 3-4, except for BOD_5, total cyanide, and dissolved metals (all analytes) because of either holding time considerations or time constraints for the sampling event. EPA also collected field measurements, including temperature and pH, at all sampling points.

EPA collected representative samples of the influent to the FGD wastewater treatment system, the distillate from the brine concentrator, and the condensate from the crystallizer. At the brine concentrator and crystallizer sampling points, EPA collected six-hour composite samples for all analytes except mercury, which was collected as three individual grab samples over the six-hour period (*i.e.*, a grab sample collected every two hours). EPA collected all analytes at the influent to the FGD wastewater treatment system as 1-day grab samples.

A sampling episode report describing the sample collection activities and the analytical results from this sampling episode is included in the rulemaking record [ERG, 2012h].

EPA also requested the collection of 1-day grab samples from a second plant in Italy, A2A's Centrale di Monfalcone (Monfalcone). This plant treats FGD wastewater using a system comprising chemical precipitation followed by vapor-compression evaporation. Monfalcone personnel collected samples of the FGD influent to wastewater treatment, the distillate from the brine concentrator, and the condensate from the crystallizer. Site visit notes and the corresponding analytical results are included in the rulemaking record [ERG, 2013].

3.4.2 CWA 308 Monitoring Program

EPA required a subset of steam electric power plants to collect samples that were used to supplement the EPA on-site sampling program. Each of the seven plants selected for the on-site sampling program (except for the Italian plant) was required to participate in the CWA 308 monitoring program so EPA could evaluate the variability associated with the FGD wastewater treatment systems' performance.

In addition to collecting the samples during the 4-day on-site sampling event, EPA required these seven plants to each collect four sets of samples over a 4- or 5-month period. The samples were collected directly by the plants and shipped to EPA-contracted laboratories for analysis.

EPA required four additional plants (not sampled by EPA) to participate in its CWA 308 monitoring program. These plants were selected to collect samples from their operations or treatment systems because EPA did not have existing data for these processes or treatment technologies. EPA obtained data from the following four plants:

- Tampa Electric Company's Polk Station (first commercially operating IGCC plant at the time of EPA's sampling program). [12]
- Wabash Valley Power Association's Wabash River Station (second commercially operating IGCC plant at the time of EPA's sampling program).
- Appalachian Power Company's Mountaineer Plant (only plant operating a carbon capture system at the time of EPA's sampling program).
- Kansas City Power & Light's Iatan Station (only plant in the United States operating an evaporation system to treat FGD wastewater at the time of EPA's sampling program).

EPA required each of these four plants to collect four consecutive days of samples at two to four locations specifically identified for each plant. The sample locations were identified to characterize gasification wastewaters, carbon capture wastewaters, and the treatment of FGD wastewater and gasification wastewater by vapor-compression evaporation systems. EPA used the same 4-consecutive-day sampling approach that it used for its on-site sampling program (as described in Section 3.4.1). These samples were collected directly by the plants and shipped to EPA-contracted laboratories for analysis.

[12] EPA identified that Duke Energy's Edwardsport Power Station also operates an IGCC system; however, it was not yet in commercial operation at the time of EPA's sampling program.

A report describing the results from the CWA 308 monitoring program is included in the rulemaking record [ERG, 2012i].

3.5 EPA and State Sources

EPA collected information about the steam electric power generating industry, treatment technologies, and the evaluated wastestreams from databases, publications, state groups, and permitting authorities. Sections 3.5.1 through 3.5.7 summarize the state and EPA data collected during the development of the Steam Electric ELG.

EPA's Office of Water (OW) coordinated its efforts with ongoing research and activities being undertaken by the EPA offices discussed below. In addition, EPA's OW also coordinated with the Office of Enforcement and Compliance Assurance (OECA) and EPA regional offices to gather further information on the industry.

3.5.1 National Pollutant Discharge Elimination System (NPDES) Permits, Permit Applications, and Fact Sheets

The CWA requires direct dischargers (*i.e.*, industrial facilities that discharge process wastewaters from any point source into receiving waters) to control their discharges according to ELGs and water quality-based effluent limitations included in NPDES permits. EPA collected and reviewed selected NPDES permits and, where available, accompanying permit applications and fact sheets to confirm or help clarify information reported in the survey responses.

3.5.2 State Groups and Permitting Authorities

Throughout the detailed study and rulemaking, EPA interacted with states and EPA regional permitting authorities, such as when contacting and visiting steam electric power plants. EPA also solicited input and suggestions from states and permitting authorities on specific steam electric power plant characteristics, ICR development, and implementation of the Steam Electric Power Generating ELGs. EPA hosted a webcast seminar in December 2008 to review information on wastewater discharges from power plants for NPDES permitting and pretreatment authorities. The webcast provided an update on EPA's review of the current ELGs (40 CFR 423) and presented information on pollutant characteristics and treatment technologies for wastewater from FGD scrubbers. During the webcast, state and interstate approaches for managing steam electric power plant wastewaters were shared by representatives from Wisconsin, North Carolina, and the Ohio River Valley Water Sanitation Commission (ORSANCO).

In November 2009, EPA held conference calls with states and EPA permitting authorities to discuss development and input for the ICR [ERG, 2009]. Additionally, EPA held a joint Federalism/Unfunded Mandates Reform Act (UMRA) consultation meeting in October 2011 to request input regarding the Steam Electric Power Generating ELGs [U.S. EPA, 2011a]. EPA also participated in periodic conference calls with ORSANCO during the rulemaking to discuss treatment technologies for managing wastewaters from steam electric power plants. Moreover, EPA coordinated with the North Carolina Department of Environmental and Natural Resources to obtain long-term characterization data from Progress Energy Carolinas' Roxboro Steam Plant for the FGD wastewater treatment influent, FGD impoundment effluent, and biological treatment effluent, as well as ash impoundment effluent data [NCDENR, 2011].

3.5.3 1974 and 1982 Technical Development Documents for the Steam Electric Power Generating Point Source Category

Two documents prepared by EPA during previous rulemakings for the Steam Electric Category have provided useful information for the current rulemaking. These documents are the 1974 *Development Document for Effluent Limitations Guidelines and New Source Performance Standards for the Steam Electric Power Generating Point Source Category* (referred to in this report as "the 1974 Development Document") [U.S. EPA, 1974] and the 1982 *Development Document for Effluent Limitations Guidelines and Standards and Pretreatment Standards for the Steam Electric Point Source Category* (referred to in this report as "the 1982 Development Document") [U.S. EPA, 1982]. These development documents contain findings, conclusions, and recommendations on control and treatment technology relating to discharges from steam electric power plants. During the current rulemaking, EPA used the information presented in the 1974 and 1982 Development Documents for historical background on the Steam Electric Power Generating ELGs and for information on sources of pollutants and wastewater characteristics.

EPA found that many steam electric power plants still use the same handling practices and treatment technologies for fly ash and bottom ash that were evaluated in the 1982 rulemaking. EPA reviewed wastewater characterization data presented in the 1982 Development Document to characterize ash impoundment effluent for the ELG. EPA determined that the method in which fly and/or bottom ash is wet sluiced to surface impoundments and management practices of those surface impoundments are relatively unchanged since promulgation of the 1982 Steam Electric ELG; therefore, the ash transport water characterization data are still valid to characterize current ash impoundment discharges.

3.5.4 CWA Section 316(b) - Cooling Water Intake Structures Supporting Documentation and Data

For the CWA section 316(b) Cooling Water Intake Structures rulemaking, EPA conducted a survey of steam electric utilities and steam electric non-utilities that use cooling water, as well as plants in four other manufacturing sectors: Paper and Allied Products (Standard Industrial Classification (SIC) code 26), Chemical and Allied Products (SIC code 28), Petroleum and Coal Products (SIC code 29), and Primary Metals (SIC code 33). The survey requested the following types of information:

- General plant information, such as plant name, location, and SIC codes.
- Cooling water source and use.
- Design and operational data on cooling water intake structures and cooling water systems.
- Studies of the potential impacts from cooling water intake structures conducted by the plant.
- Financial and economic information about the plant.

Although EPA used the Section 316(b) survey to create regulations for cooling water intake structures, the cooling water system information collected in the survey was also useful for this rulemaking effort. EPA used the information provided by the Section 316(b) survey in the following analyses:

- Identifying plant-specific cooling water sources (*e.g.*, specific rivers, streams).
- Identifying industrial non-utilities.
- Identifying the type of cooling systems used by plants.
- Linking EIA plant information to the Toxic Release Inventory (TRI) and Permit Compliance System (PCS) discharges.
- Determining plant-specific wastewater dilutions associated with cooling water prior to discharge for the Environmental Assessment (EA) analyses associated with the rulemaking effort.

3.5.5 Office of Air and Radiation

EPA's OAR works to control air pollution and radiation exposure through implementation of the Clean Air Act. EPA is taking action on climate change by developing regulations under the Clean Air Act (CAA) to reduce emissions of greenhouse gases (GHGs). OAR relies on the Integrated Planning Model (IPM) for some of its analyses of the effects of policies on the electric power sector. IPM is an engineering-economic optimization model of the electric power industry, which generates least-cost resource dispatch decisions based on user-specified constraints such as environmental, demand, and other operational constraints. The model uses a long-term dynamic linear programming framework that simulates the dispatch of generating capacity to achieve a demand-supply equilibrium on a seasonal basis and by region. In addition to existing capacity, the model also considers new resource investment options, including capacity expansion at existing plants and investment in new plants. The model is dynamic in that it is capable of using forecasts of future conditions to make decisions for the present [U.S. EPA, 2011b]. Thus, IPM incorporates electricity demand growth assumptions from the Department of Energy's Annual Energy Outlook 2013 (AEO 2013). IPM Version 5.13 (IPM V5.13) incorporates in its analytic baseline the expected compliance response for federal and state air emission laws and regulations whose provisions were either in effect or enacted and clearly delineated at the time the base case was finalized in August 2013, including: the final Mercury and Air Toxics Standards (MATS) rule; the Clean Air Interstate Rule (CAIR); regulatory sulfur dioxide (SO_2) emission rates arising from State Implementation Plans; Title IV of the Clean Air Act Amendments; NOx State Implementation Plan (SIP) Call trading program; Clean Air Act Reasonable Available Control Technology requirements and Title IV unit specific rate limits for NOx; the Regional Greenhouse Gas Initiative; Renewable Portfolio Standards; New Source Review Settlements; and several state-level regulations affecting emissions of SO_2, NOx, and mercury that were either in effect or expected to come into force by 2017. In addition, the modeling includes the proposed CAA section 111(d) Clean Power Plan and the proposed CAA section 111(b) Carbon Pollution Standards, due to time limitations for modeling (the final CAA section 111 rules were issued on August 3, 2015). This does not materially impact the analysis of the effluent guidelines since the impacts of the CAA section 111(d) rule for existing sources was similar from proposal to final rule. In addition to these air regulations, the IPM

V5.13 base case used for the analysis of the Steam Electric ELGs also takes into account the industry's expected compliance response to the CWA Section 316(b) regulations EPA promulgated in August 2014 and the Disposal of Coal Combustion Residuals from Electric Utilities (CCR) regulation EPA promulgated in December 2014. The CWA section 316(b) and CCR rule are discussed further in Sections 3.5.4 and 3.5.7, respectively.

3.5.6 Office of Research and Development

EPA's ORD is evaluating the impact of air pollution controls on the characteristics of CCRs. Specifically, ORD is studying the potential cross-media transfer of mercury and other metals from flue gas, fly ash, and other residuals collected from coal-fired boiler air pollution controls and disposed of in landfills or impoundments. The key routes of release being studied are leaching into ground water or subsequent release into surface waters, re-emission of mercury, and bioaccumulation. ORD is also examining the use of CCRs in asphalt, cement, and wallboard production.

The goal of the research is to better understand potential impacts from disposal practices and beneficial use of CCRs. The research evaluates life-cycle environmental tradeoffs that compare beneficial use applications with and without using CCRs. The outcome of this research will help to identify potential management practices of concern where environmental releases may occur, such as developing and applying a leach testing framework that evaluates a range of materials and the different factors affecting leaching for the varying field conditions in the environment.

EPA's OW consulted with ORD on the status and findings of current research assessing the potential for CCRs to impact water quality. Additionally, during EPA's sampling program, OW collected samples of CCR landfill leachate from several of the plants for characterization analysis by ORD.

3.5.7 Office of Solid Waste and Emergency Response

On December 19, 2014, EPA finalized the Disposal of Coal Combustion Residuals from Electric Utilities (CCR rule) (80 FR 21302; April 17, 2015). The rule provides requirements for the safe disposal of CCRs generated by electric utilities and independent power producers. The CCR rule is the culmination of extensive study on the effects of coal ash on the environment and public health. The rule establishes technical requirements for CCR landfills and surface impoundments under Subtitle D of the Resource Conservation and Recovery Act (RCRA), the nation's primary law for regulating solid waste. EPA used data collected by EPA's OSWER to supplement the data collected for the Steam Electric ELGs. EPA also used costing methodologies developed by EPA's OSWER to estimate certain costs associated with plants implementing the requirements of the Steam Electric ELGs, where appropriate.

As part of the CCR rule development, OSWER issued Information Request Letters to electric utilities that have surface impoundments or similar management units that contain CCRs. OSWER identified the recipients of the request letters based on plants that potentially operate CCR surface impoundments identified from data compiled in DOE's EIA databases. However, the EIA data do not include information about waste disposal practices for those plants with a nameplate electric generating capacity of less than 100 megawatts (MW). Additionally, the EIA data exclude information about impoundments at plants that use the impoundment as an interim step (*e.g.*, to dewater ash or other CCR solids), but ultimately dispose of the CCRs in an on-site landfill or off site. Therefore, OSWER may not have identified the plants operating these types of impoundments as potential recipients. As such, data collected by the OSWER survey underestimates the total number of CCR impoundments nationwide.

EPA developed a methodology to account for how operational changes associated with the CCR rule may impact the analyses for the ELGs. The analyses presented for the Steam Electric ELGs represent the current industry operations, while also taking into account the actions plants may take to implement the new requirements from the CCR rule. EPA's methodologies for incorporating the CCR rule impacts into the engineering costs and pollutant loadings and removals are described in Section 9 and Section 10.

3.6 INDUSTRY-SUBMITTED DATA

EPA obtained information on steam electric processes, technologies, wastewaters, and pollutants directly from the industry through self-monitoring data, NPDES Form 2C data, and data provided during public comment.

3.6.1 Self-Monitoring Data for Proposed Rule

Prior to the proposed rule, EPA requested self-monitoring data from Duke Energy's Belews Creek Steam Station and Allen Steam Station to evaluate the treatment efficacy and pollutant characteristics of wastewater discharged from FGD wastewater treatment systems that incorporate both chemical precipitation and biological treatment [Duke Energy, 2011a; Duke Energy, 2011b]. EPA also used these data to supplement the data from EPA's sampling program.

3.6.2 Post-Proposal Industry-Submitted Data

In addition to monitoring data and reports submitted in the Steam Electric Survey and data collected during EPA's sampling program, EPA relied on industry-supplied data and publicly available data sources, including data received during public comment, to characterize pollutant discharge concentrations and evaluate treatment technologies. In some cases, EPA requested additional information from industry to fully evaluate the data provided or to support additional analyses, including evaluating FGD wastewater treatment system performance and characterizing ash impoundment effluent. EPA collected the following types of information from industry to characterize the evaluated wastestreams and treatment system performance:

- FGD system information (*e.g.*, identity of the organosulfide additives used in each chemical precipitation treatment system, conditions within each FGD scrubber system during sampling period).
- Pollutant concentrations in FGD purge, FGD chemical precipitation effluent, and FGD biological treatment influent and effluent.
- Ash system information.
- Pollutant concentrations in ash impoundment influent and effluent.

- Pollutant concentrations in source water.
- Amount, source, sulfur content, chlorine content, and type of coal burned.

Following receipt of public comments, EPA also received additional bottom ash transport water characterization data from UWAG for consideration in the final rule.

EPA reviewed public comments received on the proposed rule related to plant-specific operations and the cost for installing or upgrading FGD wastewater treatment and ash handling technologies. EPA evaluated public comments to identify plant-specific operation and flow data and, where appropriate, used this information to revise estimates of compliance costs and pollutant removals for those facilities. One example of plant-specific revision is where a facility asserted that space constraints below the boiler made retrofitting a mechanical drag system infeasible, EPA based cost estimates for zero pollutant discharge of bottom ash transport water on the remote mechanical drag system technology.

EPA received data for plants operating FGD wastewater treatment systems through industry-submitted public comments on the proposed rule for the Steam Electric ELGs; however, EPA identified supplemental information required to evaluate FGD operations during the range of dates provided for the monitoring data. For this reason, EPA contacted the plants operating chemical precipitation or biological treatment system components that make up the BAT technology basis to request FGD wastewater characterization data (if not yet provided) and supplemental information on FGD operations over a 2-year period (*i.e.*, January 2012 – December 2013). FGD wastewater characterization data requested by EPA included chemical precipitation and biological treatment system effluent concentrations for arsenic, mercury, selenium, and several other metals. Supplemental information requested by EPA included type and source of coal, the sulfur and chlorine content of the coal used at the plant, and FGD system operational information for the range of dates for which characterization data were collected and analyzed. EPA also contacted individual plants to verify the quality of the samples and ensure that the data were appropriate for use in EPA's wastestream characterization and treatment performance evaluations.

3.6.3 NPDES Form 2C

UWAG and EPA coordinated efforts to create a database of selected NPDES Form 2C data from UWAG's member companies. Form 2C (or an equivalent form used by a state permitting authority) is an application for a permit to discharge wastewater that must be completed by industrial facilities. Information collected by this form includes facility information, data on facility outfalls, process flow diagrams, treatment information, and intake and effluent characteristics.

The Form 2C database, compiled by UWAG and provided to EPA, contains information about the outfalls of coal-fired power plants that receive FGD wastewater, ash transport water, or coal pile runoff. EPA received Form 2C data from UWAG for 86 plants in June 2008 [UWAG, 2008]. UWAG did not include data on other outfalls, such as separate outfalls for sanitary wastes, cooling water, landfill runoff, and other wastestreams, in the database. The database does not include Form 2C information for plants that have neither a wet FGD system nor wet fly ash handling. For example, if a plant has no wet FGD system and the plant's only wet ash handling is for bottom ash transport, UWAG did not include its information in the database. EPA used the Form 2C data for developing a preliminary industry profile and the Steam Electric Survey, and to evaluate and characterize ash impoundment effluent.

3.7 Technology Vendor Data

EPA gathered data from technology vendors through presentations, conferences, meetings, and email and phone contacts regarding the technologies used in the industry. The data collected informed the development of the detailed study, the industry survey, and technology costs and loadings estimates. Between 2007 and 2015, EPA participated in multiple technical conferences and reviewed the papers presented for relevant information to the rulemaking.

To gather FGD wastewater and combustion residual leachate treatment information for the cost analyses, EPA contacted companies that manufacture, distribute, or install various components of chemical precipitation and biological wastewater treatment systems and evaporation. The vendors provided the following types of information for EPA's analyses:

- Operating details.
- Performance data.
- Equipment used in the system.
- Capital cost information on a component level and system level.
- Operation and maintenance (O&M) costs.
- Equipment and system energy requirements.

To gather information on handling fly ash and bottom ash, EPA also contacted several ash handling and ash storage vendors. The vendors provided the following types of information for EPA's analyses:

- Type of fly ash and bottom ash handling systems available for reducing or eliminating ash transport water.
- Equipment, modifications, and demolition required to convert wet-sluicing fly ash and bottom ash handling systems to dry ash handling or closed-loop recycle systems.[13]
- Equipment that can be reused as part of the conversion from wet to dry handling or in a closed-loop recycle system.
- Outage time required for the different types of ash handling systems.
- Maintenance required for each type of system.
- Operating data for each type of system.
- Purchased equipment, other direct, and indirect capital costs for fly ash and bottom ash conversions.

[13] Throughout this report, EPA refers to bottom ash systems that eliminate the use of ash transport water as dry ash handling systems; however, some of these systems (*e.g.*, mechanical drag system) still use water in a quench bath and, therefore, are not completely dry systems.

- Specifications for the types of ash storage available (*e.g.*, steel silos or concrete silos) for the different types of handling systems.
- Equipment and installation capital costs associated with the storage of fly ash and bottom ash.
- Operation and maintenance costs for fly ash and bottom ash handling systems.

To obtain additional information on FGD treatment systems and fly ash and bottom ash conversions, EPA conducted meetings, conference calls, and site visits with treatment and ash vendors. The information collected from technology vendors is detailed further in the *Incremental Costs and Pollutant Removals for the Final Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* [ERG, 2015].

3.8 OTHER DATA SOURCES

EPA obtained additional information on steam electric processes, technologies, wastewaters, pollutants, and regulations from sources including UWAG, the Electric Power Research Institute (EPRI), DOE, literature and Internet searches, and environmental groups and other stakeholders.

3.8.1 Utility Water Act Group

UWAG is an association of over 200 individual electric utilities and four national trade associations of electric utilities: the Edison Electric Institute, the National Rural Electric Cooperative Association, the American Public Power Association, and the Nuclear Energy Institute. UWAG's purpose is to participate on behalf of its members in EPA's rulemakings under the CWA. Specifically, EPA coordinated with UWAG on collecting information on power plant characteristics to support site visit selection, discussing wastewater sampling approaches and recommendations, discussing laboratory analytical methods, reviewing the questionnaire for clarity, reviewing the questionnaire mailing list to confirm plants and mailing addresses, and collecting existing permit data. At the invitation of individual plants, UWAG representatives also collected split samples during EPA's on-site sampling and CWA 308 monitoring programs and participated in most site visits. Additionally, UWAG coordinated with individual plants to submit public comments, including the plant-specific wastewater characterization data discussed in Section 3.6.2.

3.8.2 Electric Power Research Institute

EPRI is a research-oriented trade association for the steam electric power generating industry. EPRI conducts research funded by the steam electric power generating industry and has extensively studied wastewater discharges from FGD systems. Table 3-5 presents the reports provided to EPA by the trade association that summarize the data collected during several EPRI studies.

In addition, as part of their response to the Steam Electric Survey*,* several steam electric power plants submitted EPRI studies on wastewater discharges from FGD systems and ash impoundments at their plants.

The EPRI reports provided EPA with the following: background information regarding the characteristics of FGD wastewaters and the sampling techniques used during the program; information regarding the characteristics of discharges from fly ash and bottom ash impoundments and the respective percentage of loadings from ash impoundments containing both fly ash and bottom ash; and information on the treatment technologies available to treat FGD and ash wastewaters, including findings from pilot-study evaluations.

EPA reviewed all EPRI reports to determine if they contained FGD wastewater or ash impoundment characterization data that met all acceptance criteria. As described in Sections 11 and 12 of the *Incremental Costs and Pollutant Removals for the Final Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* report [ERG, 2015] for this rulemaking, EPA used data from EPRI reports to characterize FGD wastewater or ash transport water.

EPRI conducts industry-funded studies to evaluate and demonstrate technologies that can potentially remove trace metals from FGD wastewater. EPRI conducted pilot- and full-scale optimization field studies on some technologies already used by coal-fired power plants to treat FGD wastewater, such as chemical precipitation, constructed wetlands, and anoxic/anaerobic biological treatment systems. In addition, EPRI has conducted studies for other technologies that can potentially remove metals from FGD wastewaters. EPA analyzed EPRI reports describing alternative FGD wastewater treatment technologies as bench-, pilot-, and full-scale. EPA's evaluation of alternative treatment technologies is further discussed in Section 7.1.7.

EPRI also participated in meetings with EPA and provided comments on EPA's planned data collection activities, including the Steam Electric Survey and the sampling program.

Table 3-5. Reports and Studies Submitted to EPA from EPRI

Title of Report/Study	Document Control Number
PISCES Wastewater Characterization Field Study, Sites A-G	DCNs SE01818-SE01823
The Fate of Mercury Absorbed in Flue Gas Desulfurization (FGD) Systems	DCN SE01814
Flue Gas Desulfurization (FGD) Wastewater Characterization: Screening Study	DCN SE01816
EPRI Technical Manual: Guidance for Assessing Wastewater Impacts of FGD Scrubbers	DCN SE01817
Update on Enhanced Mercury Capture by Wet FGD: Technical Update	DCN SE01815
Selenium Removal by Iron Cementation from a Coal-Fired Power Plant Flue Gas Desulfurization Wastewater in Continuous Flow System – A Pilot Study	DCN SE0409A2
Laboratory and Pilot Evaluation of Iron and Sulfide Additives with Microfiltration for Mercury Water Treatment	DCN SE0409A3
Impact of Wet Flue Gas Desulfurization (FGD) Design and Operating Conditions on Selenium Speciation: 2009 Update	DCN SE04369
Integrated Fly Ash Pond Management: A Field Study of Five Central United States Pond Systems.	DCN SE04361
Current Practices for Flue Gas Desulfurization (FGD) Water Management and Treatment in Ponds	DCN SE04367

Table 3-5. Reports and Studies Submitted to EPA from EPRI

Title of Report/Study	Document Control Number
Pilot-Scale and Full-Scale Evaluation of Treatment Technologies for the Removal of Mercury and Selenium in Flue Gas Desulphurization Water	DCN SE04362
Impact of Wet Flue Gas Desulfurization (FGD) Design and Operating Conditions on Selenium Speciation: 2010 Update	DCN SE04370
Review of Water Treatment Technologies for Selenium Removal Implemented at Power Plants	DCN SE04363
Evaluation of Mercury Speciation and Its Treatment Implication in Flue Gas Desulfurization Waters	DCN SE04368
Thermal Flue Gas Desulfurization Wastewater Treatment Processes for Zero Liquid Discharge Operations	DCN SE04365
Selenium Speciation and Management in Wet FGD Systems	DCN SE04364
Corrosion in Wet Flue Gas Desulfurization (FGD) Systems: Technical Root Cause Analysis of Internal Corrosion on Wet FGD Alloy Absorbers	DCN SE04366
Pilot Evaluation of the Anaerobic Membrane Bioreactor Technology for Flue Gas Desulfurization Wastewater Treatment	DCN SE05615
Pilot Evaluation of the Pironox™ System for Flue Gas Desulphurization Wastewater Treatment	DCN SE05616
Pilot Evaluation of a Fluidized Bed Reactor/Membrane Bioreactor Technology for Flue Gas Desulfurization Wastewater Treatment	DCN SE05617
Pilot Evaluation of the ABMet Technology for Flue Gas Desulphurization Wastewater Treatment	DCN SE05618
Pilot Evaluation of the ZVI Blue™ Technology for Flue Gas Desulphurization Wastewater Treatment	DCN SE05619

3.8.3 Department of Energy

DOE is the department of the United States government responsible for energy policy. EPA used information on electric generating plants from DOE's EIA data collection forms.

The Agency used information from two of EIA's data collection forms: Form EIA-860, Annual Electric Generator Report, and Form EIA-923, Power Plant Operations Report. Form EIA-860 collects information annually from all electric generating facilities that have or will have a nameplate capacity of 1 MW or more and are operating or plan to be operating within 5 years of filing this form.[14] The data collected in Form EIA-860 are associated only with the design and operation of generators at facilities [U.S. DOE, 2007a; U.S. DOE, 2009a]. Form EIA-923 collects information from electric power plants and combined heat and power plants in the United States that have a total generator nameplate capacity greater than 1 MW. The form asks where the generator(s) resides, and if it is connected to the local or regional electric power grid

[14] DOE defines the generator nameplate capacity as the maximum rated output of a generator under specific conditions designated by the manufacturer. Generator nameplate capacity is usually indicated in units of kilovolt-amperes (kVA) and in kilowatts (kW) on a nameplate physically attached to the generator. More generally, generator capacity is the maximum output, commonly expressed in MW, that generating equipment can supply to system load, adjusted for ambient conditions.

and has the ability to draw power from the grid or deliver power to the grid. The data collected in Form EIA-923 are associated with the operation and design of the entire facility [U.S. DOE, 2007b and 2009b]. EPA used these data to help identify the industry sample frame for the Steam Electric Survey. Additionally, EPA used these data to supplement Steam Electric Survey data, such as age of the generating units, which was not requested in the survey.

3.8.4 Literature and Internet Searches

EPA conducted literature and Internet searches to obtain information on various aspects of the steam electric power generating process. The objectives of these searches included characterizing wastewaters and pollutants originating from these steam electric power generating processes, the environmental impacts of these wastewaters, and applicable regulations. EPA also used the Internet searches to identify or confirm reports of planned plant/unit retirements or reports of planned unit conversions to dry or closed-loop recycle ash handling systems. EPA used industry journals, standard engineering design and cost references, reference texts about the industry, and company press releases obtained from Internet searches to inform the industry profile and process modifications occurring in the industry.

In addition to chemical precipitation, biological treatment, vapor-compression evaporation, constructed wetlands, and zero discharge systems for FGD wastewater treatment, EPA also identified several emerging treatment technologies that are being developed to treat FGD wastewater. EPA analyzed industry sources and published research articles describing alternative FGD wastewater treatment technologies at bench-, pilot-, and full-scale levels. EPA's evaluation of alternative treatment technologies is further discussed in Section 7.1.7.

3.8.5 Environmental Groups and Other Stakeholders

EPA received information from several environmental groups and other stakeholders as part of public comments received on the 2006 and 2008 Effluent Guidelines Plans and the proposed ELGs, during development of the survey, and in other discussions during the detailed study and rulemaking. In general, the information highlights the environmental concerns associated with the pollutants present in steam electric power plant wastewaters, and technological controls for reducing or eliminating pollutant discharges from FGD and ash handling systems.

3.8.6 EPA Public Meetings

On July 9, 2013, EPA held a pretreatment public hearing about the pretreatment standards contained in the proposed Steam Electric ELGs. This hearing collected oral public comments from 55 commenters and written comments from 38 commenters [U.S. EPA, 2013a]. In addition, on August 20, 2013, EPA held a webinar where EPA presented a summary of the proposed rule and answered questions raised by participants. The presentation given by EPA and the transcript from the webinar are included in the record [U.S. EPA, 2013b].

3.9 PROTECTION OF CONFIDENTIAL BUSINESS INFORMATION

Certain data in the rulemaking record have been claimed as confidential business information (CBI). As required by federal regulations at 40 CFR 2, EPA has taken precaution to prevent the inadvertent disclosure of this CBI. The Agency has withheld CBI from the public docket in the Federal Docket Management System. In addition, EPA has withheld from disclosure some data not claimed as CBI because the release of these data could indirectly reveal CBI. Furthermore, EPA has aggregated certain data in the public docket, masked plant identities, or used other strategies to prevent the disclosure of CBI. The Agency's approach to protecting CBI ensures that the data in the public docket both explain the basis for the rule and provide the opportunity for public comment, without compromising data confidentiality.

3.10 References

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SECTION 4
STEAM ELECTRIC INDUSTRY DESCRIPTION

Electricity is produced by converting mechanical, chemical, and/or fission energy into electrical energy, and may or may not involve the use of steam. This section provides an overview of the various types of electric generating processes operating in the United States and describes more fully the categories of processes regulated by the Steam Electric Power Generating effluent limitations guidelines and standards (ELGs). Section 4.1 describes the electric power generating industry, including demographics of the steam electric power generating industry; Section 4.2 describes the steam electric power generating process; Section 4.3 describes the wastestreams generated by the steam electric power generating industry that were evaluated for new controls in the ELGs; and Section 4.4 describes the wastestreams generated by the steam electric power generating industry that were not evaluated for new controls in the ELGs.

4.1 OVERVIEW OF ELECTRIC GENERATING INDUSTRY

This section describes the plants that compose the overall electric generating industry as well as the definition of the Steam Electric Power Generating Point Source Category (Steam Electric Category). As shown in Figure 4-1, the plants regulated by the Steam Electric Power Generating ELGs are only a portion of the electric generating industry.

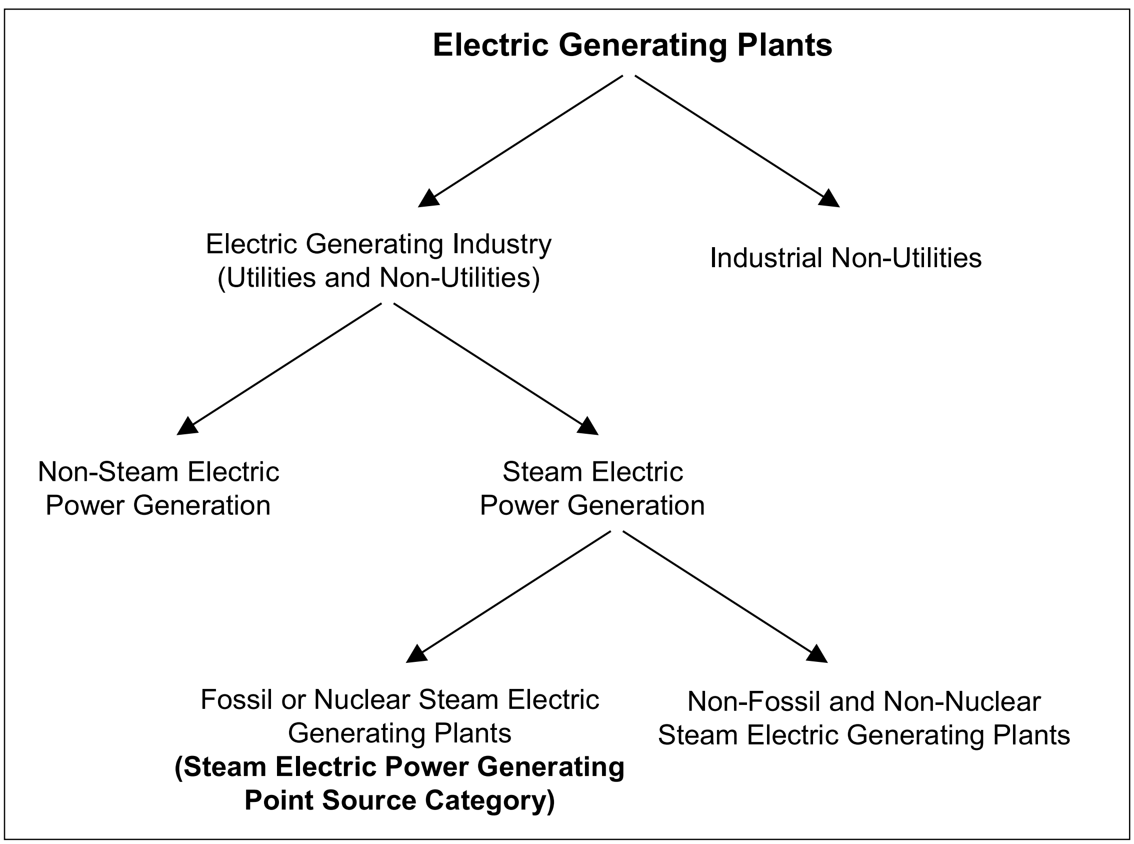


Figure 4-1. Types of U.S. Electric Generating Plants

4.1.1 Electric Generating Industry Population

In general, the companies generating electrical power are categorized as one of the following types:

- *Utility*: Any entity that generates, transmits, and/or distributes electricity and recovers the cost of its generation, transmission and/or distribution assets and operations, either directly or indirectly, through cost-based rates set by a separate regulatory authority (*e.g.*, state Public Service Commission), or is owned by a governmental unit or the consumers that the entity serves. According to the Department of Energy (DOE)'s Energy Information Administration (EIA), plants that qualify as cogenerators or small power producers under the Public Utility Regulatory Policies Act are not considered electric utilities [U.S. DOE, 2012a; U.S. DOE, 2012b].
- *Non-Industrial Non-Utility*: Any entity that generates, transmits, and/or sells electricity, or sells or trades electricity services and products, where costs are not established and recovered by a regulatory authority. Non-utility power producers include, but are not limited to, independent power producers, power marketers and aggregators, merchant transmission service providers, self-generation entities, and cogeneration firms with Qualifying Facility Status [U.S. DOE, 2012a; U.S. DOE, 2012b]. Like utilities, the primary purpose of non-industrial non-utilities is producing electric power for distribution and/or sale.
- *Industrial Non-Utility*: Industrial non-utilities are similar to non-industrial non-utilities except their primary purpose is not distributing and/or selling electricity. This category includes electric generators that are located at industrial plants such as chemical manufacturing plants or paper mills. Industrial non-utilities typically provide most of the electrical power they generate to the industrial operation with which they are located, although they may also provide some electric power to the grid for distribution and/or sale.

This section presents available demographic data and other information for the electric generating industry, excluding industrial non-utilities. EPA analyzed the available demographic information using EIA data for the year 2009 (Form EIA-860) [U.S. DOE, 2009] and U.S. Census Bureau data collected in the 2007 Economic Census [USCB, 2007]. EPA used the 2009 EIA data because data collected from the steam electric power generating industry via EPA's *Questionnaire for the Steam Electric Power Generating Effluent Guidelines* (Steam Electric Survey) represent plant-level operations in 2009, and used the 2007 Census data because, as a 5-year census, it is the closest year to the Steam Electric Survey for which data are available. Together, these sources provide the most comprehensive set of power plant data available. EPA identified electric generating plants in the EIA database as those reporting North American Industrial Classification System (NAICS) code 22 – Utilities.[15] The 2007 Economic Census data

[15] NAICS code 22 – *Utilities* is defined as establishments providing the following utility services: electric power, natural gas, steam supply, water supply, and sewage removal. Excluded from this sector are establishments primarily engaged in waste management services [USCB, 2007].

include more specific industry sector information at the six-digit North American Industry Classification System (NAICS) code level.

EPA also examined the data on operations that electric generating plants reported to the EIA in 2009. Form EIA-860 contains records for 15,169 steam and non-steam-electric generating units having at least one megawatt (MW) of capacity operated at 5,300 facilities for calendar year 2009 [U.S. DOE, 2009]. Because the EIA data also include units at industrial non-utilities, they overestimate the number of units and plants that may be considered part of the electric generating industry.

According to the Economic Census, there were 1,934 electric generating plants in the United States in 2007, 69 percent (1,327 plants) of which were characterized primarily as using fossil or nuclear fuel [USCB, 2007]. These data include both steam and non-steam-electric generating processes. Table 4-1 presents the distribution of plants among each of the electric generating NAICS codes. The Economic Census includes all facilities reporting under NAICS code 22. As a result, it includes entities categorized by DOE as utilities and non-industrial non-utilities, but does not include industrial non-utilities.

Table 4-1. Distribution of U.S. Electric Generating Plants by NAICS Code in 2007

NAICS Code – Description	Plants
221111 – Hydroelectric Power Generation	295
221112 – Fossil Fuel Electric Power Generation	1,248
221113 – Nuclear Electric Power Generation	79
221119 – Other Electric Power Generation (includes conversion of other forms of energy, such as solar, wind, or tidal power, into electrical energy)	312
22111 – Electric Power Generation (Total)	**1,934**

Source: U.S. Census [USCB, 2007].

4.1.2 Applicability of Steam Electric Power Generating Effluent Guidelines

Industrial non-utilities are not included within the scope of the existing Steam Electric Power Generating ELGs because they are not primarily engaged in producing electricity for distribution and/or sale.[16] As described above, these industrial non-utilities typically are industrial plants that produce, process, or assemble goods, and the electricity generated at these plants is an ancillary operation used to dispose of a by-product or for cost savings.

Because industrial non-utilities are not included in the applicability of the Steam Electric Power Generating ELGs, EPA has excluded them from the discussion of the U.S. electric generating industry for the purposes of this document. Therefore, information presented on

[16] The applicability of the Steam Electric Power Generating Point Source Category (40 CFR 423.10) states that "the provisions of this part apply to discharges resulting from the operation of a generating unit by an establishment whose generation of electricity is the predominant source of revenue or principal reason for operation, and which results primarily from a process utilizing fossil-type fuel (coal, oil, or gas), fuel derived from fossil fuel (*e.g.*, petroleum coke, synthesis gas), or nuclear fuel in conjunction with a thermal cycle employing the steam water system as the thermodynamic medium."

plants composing the electric generating industry includes only the utilities and the non-industrial non-utilities. Although the transmission and distribution entities are included in the definition of utilities and non-industrial non-utilities, they are not included in the Steam Electric Category; therefore, this document presents information only on the plants and NAICS codes associated with the generation of electricity.

As shown in Figure 4-1, the electric generating industry can be further broken down based on the type of prime mover used to generate electricity. EIA defines a prime mover as the engine, turbine, water wheel, or similar machine that drives an electric generator or a device that converts energy to electricity directly (*e.g.*, photovoltaic solar and fuel cell(s)) [U.S. DOE, 2012c]. Because the Steam Electric Power Generating ELGs are applicable only to plants generating electricity using a "thermal cycle employing the steam water system as a thermodynamic medium," EPA categorized the prime movers into "steam electric" and "non-steam-electric" categories. The steam electric generating units include steam turbines and combined cycle systems (see Sections 4.2.1 and 4.2.2 for more details on these types of units). The non-steam-electric generating units include, but are not limited to, stand-alone combustion turbines, internal combustion engines, fuel cells, and wind turbines.

The final criterion for a plant to meet the applicability of the Steam Electric Power Generating ELGs is that it must primarily utilize a fossil or nuclear fuel to generate the steam used in the turbine. Fossil fuels include coal, oil, or gas, and fuels derived from coal, oil, or gas such as petroleum coke, residual fuel oil, and distillate fuel oil. Fossil fuels also include blast furnace gas and the product of gasification processes using fossil-based feedstocks such as coal, petroleum coke, and oil. Examples of nonfossil/nonnuclear fuels used by some steam electric power plants include pulp mill black liquor, municipal solid waste, and wood solid waste.

4.2 STEAM ELECTRIC GENERATING INDUSTRY

EPA identified the subset of electric generating plants in the EIA database that use steam electric processes as those operating at least one prime mover that utilizes steam. The following electric generating unit or prime mover types specified in the EIA database are included in the steam electric industry:

- Steam turbine.
- Combined cycle system – steam turbine portion.
- Combined cycle system – combustion turbine portion.[17]
- Combined cycle single shaft – steam and combustion turbines sharing a single shaft.

Within each prime mover category, electric generating units are also classified by type of unit based on how often the units are in operation. Units can be classified as baseload, peaking, cycling, or intermediate. Baseload units produce electricity at an essentially constant rate and typically run for extended periods, peaking units operate during peak-load periods, cycling units

[17] Although the combustion turbine portion of the combined cycle system does not use steam to turn the turbine, the combined cycle system does use steam associated with the steam turbine portion; therefore, both portions are included in the analysis because the entire combined cycle system is covered under the Steam Electric Power Generating ELGs (See 40 CFR 423.10).

generally operate in a routine cycle (*i.e.*, only operating during the day), and intermediate units produce electricity on an as-needed basis operating more frequently than peaking units but less frequently than baseload units.

The subset of steam electric power plants that are regulated by the Steam Electric Power Generating ELGs use a fossil or nuclear fuel as the primary energy source for the steam electric generating unit. In analyzing the EIA data, EPA included plants using the following EIA-defined nuclear and fossil (or fossil-derived) fuel types:

- Anthracite coal.
- Bituminous coal.
- Lignite coal.
- Subbituminous coal.
- Coal synfuel.
- Waste/other coal.
- Petroleum coke.
- No. 1 Fuel Oil.
- No. 2 Fuel Oil.
- No. 4 Fuel Oil.
- No. 5 Fuel Oil.
- No. 6 Fuel Oil.
- Diesel Fuel.
- Jet fuel.
- Kerosene.
- Oil-other and waste oil (*e.g.*, crude oil, liquid by-products, oil waste, propane (liquid), rerefined motor oil, sludge oil, tar oil).
- Natural gas.
- Blast furnace gas.
- Gaseous propane.
- Other gas.
- Nuclear (*e.g.*, uranium, plutonium, thorium).

Using the criteria for the prime mover type and energy source described above for all plants (utilities and non-industrial non-utilities) reporting a NAICS code of 22 to EIA in 2009, EPA identified 1,179 steam electric power plants potentially subject to the Steam Electric Power Generating ELGs. In analyzing the EIA energy source data for the purpose of this report, EPA limited the analysis to identify only those plants/units that reported one of the above energy sources as a "primary" energy source or that reported coal or petroleum coke as either the "primary" or "secondary" energy source in the 2009 EIA data.[18] The 1,179 plants operate an

[18] For the purposes of this analysis, EPA included only plants/units based on the "secondary" energy source when it was reported as a type of coal or petroleum coke. For example, if a generating unit reported the "primary" energy source as municipal solid waste and the "secondary" energy source as coal, the plant was included in the analysis;

estimated 3,341 stand-alone steam electric generating units or combined cycle systems, which have a total generating capacity of 778,000 MW [U.S. DOE, 2009].

4.2.1 Steam Electric Generating Process

Steam electric power plants generate electricity using a process that includes a steam generator (*i.e.*, boiler), a steam turbine/electrical generator, and a condenser. Figure 4-2 illustrates the stand-alone steam electric power generation process, which uses a combustible fuel as the energy source to generate steam. The Steam Electric Power Generating ELGs regulate wastewater discharged by those steam electric power plants that use fossil-type fuel (*e.g.*, coal, oil, or gas) or nuclear fuel to generate the steam. As shown in Figure 4-2, fuels are fed to a boiler where they are combusted to generate steam. Boilers and their associated subsystems often include components to improve thermodynamic efficiency by boosting steam temperature and preheating intake air using superheaters, reheaters, economizers, and air heaters. The hot gases from combustion (*i.e.*, the flue gas) leave the steam generator subsystem and pass through particulate collection and the sulfur dioxide (SO_2) scrubbing system (if present), and then are emitted through the stack. Natural gas-fired units typically do not operate these types of air pollution controls. The high-temperature, high-pressure steam leaves the boiler and enters the turbine generator where it drives the turbine blades as it moves from the high-pressure to the low-pressure stages of the turbine. The spinning of the turbine blades drives the linked generator, producing electricity. The lower-pressure steam leaving the turbine enters the condenser, where it is cooled and condensed by the cooling water flowing through heat exchanger (condenser) tubes. The water collected in the condenser (condensate) is returned to the boiler where it is again converted to steam [Babcock & Wilcox, 2005].

Combusting coal, petroleum coke, and oil in steam electric boilers produces a residue of noncombustible fuel constituents, referred to as ash. Some of the ash consists of very fine particles that are light enough to be entrained in the flue gas and carried out of the furnace. This is commonly known as fly ash. The heavier ash that settles in the furnace or is dislodged from furnace walls is collected at the bottom of the boiler and is referred to as bottom ash.

Combusting fossil fuels also generates pollutants in the flue gas (*e.g.*, nitrogen oxides, SO_2) that, if not removed, would be emitted to the atmosphere. Therefore, many plants operate air pollution control technologies that remove these pollutants from the flue gas. The following are some of the common air pollution control technologies used in the industry and the pollutants they are primarily used to control:

- Electrostatic precipitator (ESP): fly ash/particulate matter.
- Flue gas desulfurization (FGD): SO_2.
- Selective catalytic reduction (SCR): nitrogen oxides.
- Selective non-catalytic reduction (SNCR): nitrogen oxides.
- Flue gas mercury controls (FGMC): mercury.

however, if the generating unit reported the "secondary" energy source as natural gas, then the plant would not have been included in the analysis.

The nuclear-fueled steam electric process is similar to the steam/water system described above. The nuclear system differs from the nonnuclear system in three key ways: fuel handling, nuclear fission within the reactor core instead of the boiler as the heat source for producing steam, and no air pollution control equipment. No fuel is combusted and no ash is generated in a nuclear-fueled steam electric power generating process. Instead, heat transferred from the reactor core creates steam in boiling water reactors or creates superheated water in pressurized-water reactors. The steam turbine/electric generator and condenser portions of the nuclear-fueled steam electric power generating process are the same as those described for the stand-alone steam electric process [U.S. DOE, 2006].

4.2.2 Combined Cycle Systems

Some steam electric power plants operate one or more combined cycle systems fueled by fossil or fossil-type fuels to produce electricity. Figure 4-3 illustrates the combined cycle system process. A combined cycle system comprises one or more combustion turbine electric generating units operating in conjunction with one or more steam turbine electric generating units. Combustion turbines, which typically are similar to jet engines, commonly use natural gas as the fuel, but may also use other fuels, such as oil or synthetic gas. Exhaust gases from combustion are sent directly through the combustion turbine, which is connected to a generator to produce electricity. The exhaust gases exiting the combustion turbine still contain useful waste heat, so they are directed to heat recovery steam generators (HRSGs) to generate steam to drive an additional turbine. The steam turbine is also connected to a generator (which may be a different generator or the same generator that is connected to a combustion turbine) that produces additional electricity. Thus, combined cycle systems use steam turbine technology to increase the efficiency of the combustion turbines.

Steam electric generating units within combined cycle systems operate almost identically to stand-alone steam electric generating units, except without the boiler. In a combined cycle system, the combustion turbines and HRSGs functionally take the place of the boiler of a stand-alone steam electric generating unit. The other two major components of steam electric generating units within combined cycle systems, the steam turbine/electric generator and steam condenser, are virtually identical to those of stand-alone steam electric generating units. Thus, the wastewaters and pollutants generated from both types of systems are the same. However, the wastewaters of the combined cycle units are more closely associated with gas-fired steam electric generating units, and therefore do not typically generate ash or FGD wastewaters. The wastewaters generated from combined cycle units typically include cooling water, boiler blowdown, metal cleaning wastes, and steam condensate water treatment wastes.

4.2.3 Integrated Gasification Combined Cycle Systems

Integrated gasification combined cycle (IGCC) systems combine gasification technology with both gas turbine and steam turbine power generation (*i.e.*, combined cycle power generation). Figure 4-4 presents a general process flow diagram for an IGCC system. In an IGCC system, a gasifier converts carbon-based feedstock (*e.g.*, coal or petroleum coke) into a synthetic gas ("syngas"). The syngas is cleaned of particulates, sulfur, and other contaminants and is then combusted in a high-efficiency combustion gas turbine/generator. An HRSG then extracts heat from the combustion turbine exhaust to produce steam and drive a steam turbine/generator.

IGCC plants can achieve higher thermodynamic efficiencies, emit lower levels of criteria air pollutants, and consume less water per MW than traditional coal combustion power plants. Like typical combustion power plants, solid wastes and wastewater are generated from the gasification process.

DOE's National Energy Technology Laboratory (NETL) Gasification World Database reports three commercial-scale IGCC systems located in the United States; the 262-MW Wabash River IGCC Repowering Project (Wabash River) in Indiana, the 250-MW Tampa Electric Polk Power Station IGCC Project (Polk) in Florida, and the 618-MW Edwardsport IGCC Project in Indiana [U.S. DOE, 2014]. Other U.S. power companies are investigating or planning IGCC systems at new or existing plants, such as the 582-MW Kemper County IGCC Project in Mississippi, which is under construction and is expected to begin commercial operation in early to mid-2016. The system at Kemper County will achieve zero discharge of its gasification wastewater and will include a carbon capture system [Southern Company, 2015]. EPA has conducted site visits at the Wabash River, Polk, and Edwardsport plants. The specific gas preparation and by-product recovery operations at the plants may vary, but each uses the same general electric power generating process as shown in Figure 4-4. For example, Polk operates a sulfuric acid plant to recover sulfur, while Wabash River uses the Claus process to generate an elemental sulfur product [ERG, 2009; ERG, 2011].

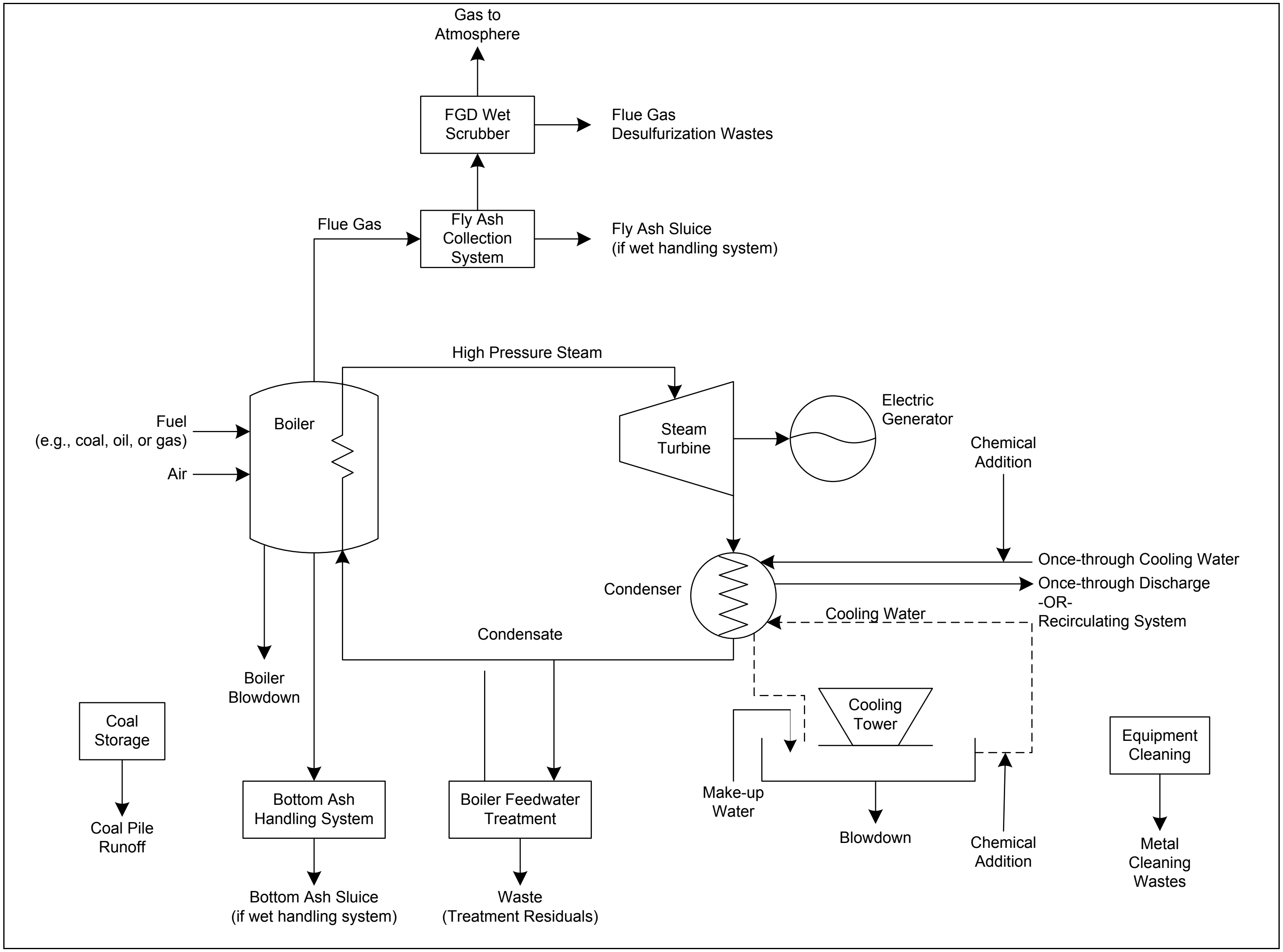


Figure 4-2. Steam Electric Power Generating Process Flow Diagram

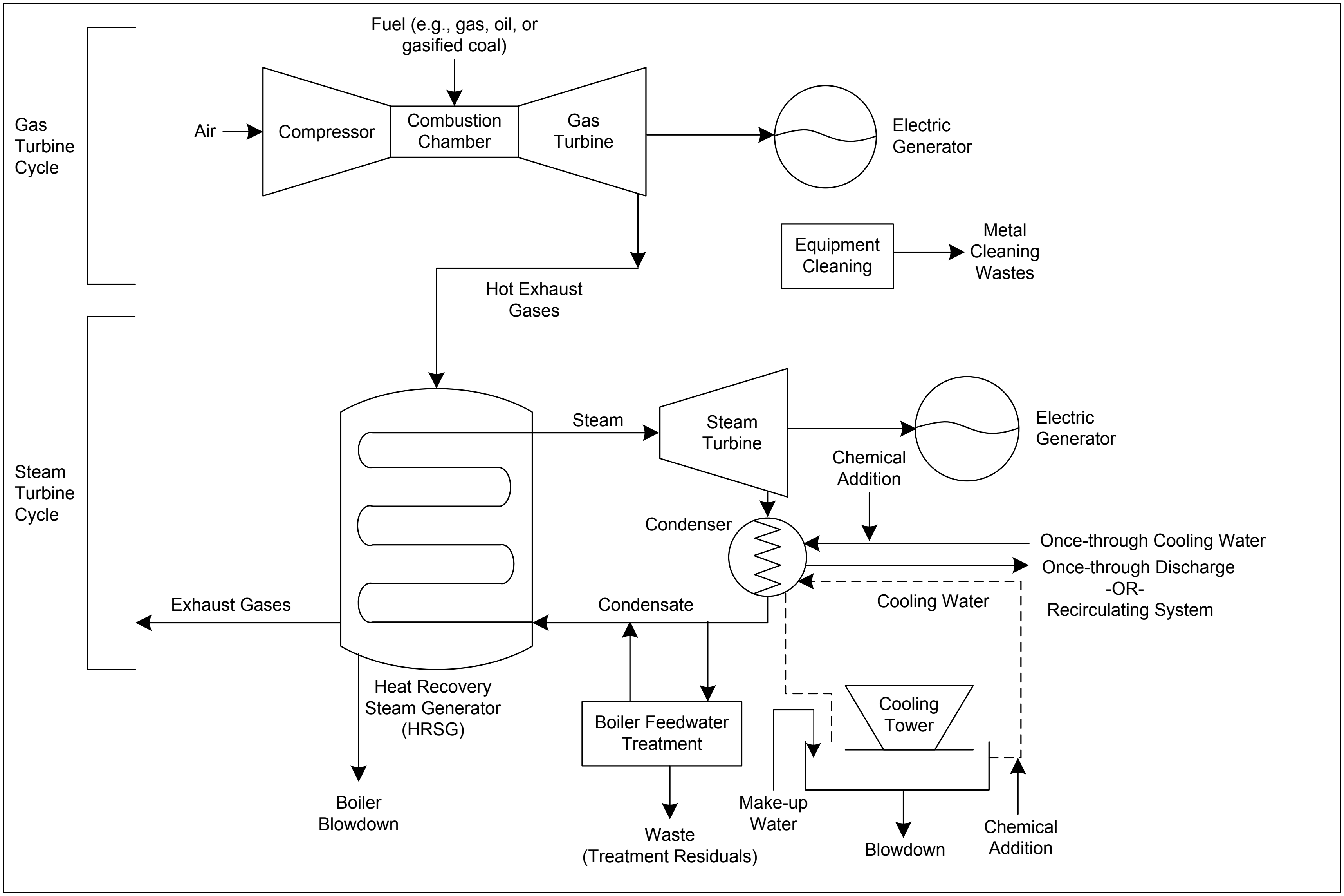


Figure 4-3. Combined Cycle Process Flow Diagram

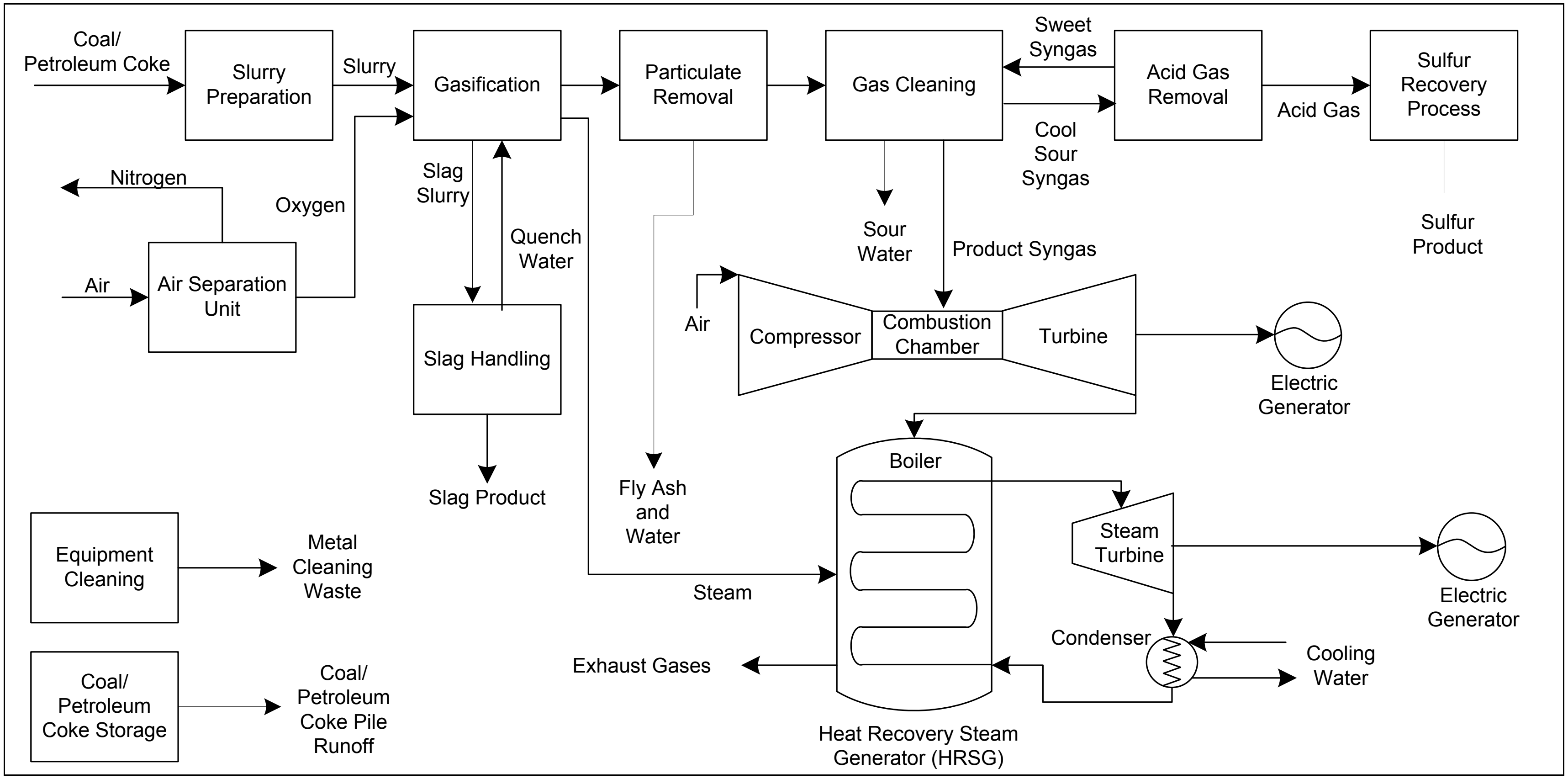


Figure 4-4. IGCC Process Flow Diagram

4.2.4 Demographics of the Steam Electric Power Generating Industry

In 2010, EPA's Office of Water administered the *Questionnaire for the Steam Electric Power Generating Effluent Guidelines* (Steam Electric Survey) to power plants believed to be subject to the Steam Electric Power Generating ELGs. As described in Section 3.2, EPA distributed the Steam Electric Survey to all coal- and petroleum coke-fired plants identified in the 2007 EIA and a statistically sampled subset of steam electric power plants burning other types of fuel, including oil-fired, gas-fired, and nuclear-fueled fire. EPA obtained information on specific aspects of power plant operation for the 2009 calendar year. The Steam Electric Survey also requested information about planned steam electric generating units, wastewater treatment systems, and other improvements or modifications through the year 2020. EPA uses data from the Steam Electric Survey throughout this document to describe the state of the steam electric power generating industry and to make projections on the general direction of the industry in the near future. As described in Section 4.5 and later sections, EPA considered plant and generating unit retirements, fuel conversions (repowering), ash handling conversions, wastewater treatment upgrades, and other industry profile changes in the development of the regulatory options and supporting technical analyses; however, the data presented in this section represent 2009 conditions, unless otherwise noted. Although there have been some changes in the industry since EPA conducted the survey (and these are reflected to the extent practicable in the ELG analyses), the survey remains the best available source of information for characterizing operations across the industry. The Steam Electric Survey data presented in this document are based on reported values, which were scaled up to represent the steam electric power generating industry in 2009 as a whole using the industry-weighting factors discussed in Section 3.2.

Table 4-2 presents the distribution of the types of steam electric prime movers used by plants to which the Steam Electric Power Generating ELGs apply using both 2009 EIA data and EPA's Steam Electric Survey data. The table includes the numbers of plants, electric generating units, and capacity for each type of steam electric prime mover. The number of electric generating units represents the number of generators/turbines used to generate electricity and does not necessarily relate to the number of boilers. As shown in Table 4-2, the Steam Electric Survey estimates are lower than the 2009 EIA data estimates. The EIA data indicate that there were 1,179 plants operating at least one steam electric generating unit powered by a fossil or nuclear fuel in 2009. Based on the weighted Steam Electric Survey data, however, the industry had 1,079 plants operating at least one steam electric generating unit in 2009.[19] As described in Section 3.2, the Steam Electric Survey captured data from plants identified using 2007 EIA data but responses reflect data for the 2009 production year. The steam electric power generating industry is dynamic; the discrepancies between Steam Electric Survey data and the 2009 EIA data could be due to new installations, unit fuel conversions, and plant/unit retirements. In addition, the Steam Electric Power Generating ELGs are not applicable to all units generating electricity. Units that do not burn fossil fuels or plants with a primary purpose other than generating electricity do not fall under the applicability of the Steam Electric ELGs. Since the survey provides more complete information about power plant operations and is a better source for identifying plants that are covered by the ELGs, EPA used the weighted Steam Electric

[19] EPA identified another plant that began operation after the time period for the Steam Electric Survey, resulting in a total baseline population of 1,080 plants for the ELG analyses.

Survey results for the remainder of the analyses in this document to represent the steam electric power generating industry in 2009.

Based on the Steam Electric Survey data, the majority (71 percent) of the steam electric power produced by the plants subject to the ELGs is generated using stand-alone steam turbines, which are also the most prevalent type of steam electric prime mover used. Table 4-3 presents the distribution of fossil and nuclear fuels used to power each type of steam electric prime mover. The number of electric generating units represents the number of generators/turbines used to generate electricity and is not equal to the number of boilers. The vast majority (93 percent) of these generating units burn at least some amount of either coal or gas. 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 are not very prevalent in the industry, accounting for roughly only 3 to 4 percent of the total number of generating units and capacity.

Table 4-4 presents the steam electric capacity, as well as the number of steam electric power plants distributed by *overall plant capacity.*[20] Table 4-4 includes the stand-alone steam turbines and all the combined cycle system turbines (*i.e.*, combined cycle steam turbine, combined cycle single shaft, and combined cycle combustion turbine) in the number of steam electric power plants and steam electric capacity. According to the weighted Steam Electric Survey data, the largest capacity plants (>500 MW) make up over 60 percent of all steam electric power plants and 90 percent of the steam electric generating capacity for all plants regulated by the ELGs. Based on the weighted Steam Electric Survey data, most steam electric power plants are either gas- or coal-fired and have a generating capacity greater than 500 MW.

Table 4-5 presents the steam electric power generating industry broken out by size of the generating units. Table 4-5 includes the stand-alone steam turbines and the all the combined cycle steam turbines. To determine the size of the combined cycle generating units, EPA added the capacity for all combined cycle turbines (*i.e.*, combined cycle steam turbine, combined cycle single shaft, and combined cycle combustion turbine) for each turbine identified for the specific generating unit.

Stand-alone steam turbines are more prevalent than combined cycle units within the steam electric power generating industry. These stand-alone steam turbines are generally larger units, with 70 percent having a capacity of 500 MW or greater. In most cases, stand-alone steam turbines will burn coal- or petroleum coke as either a primary or a secondary fuel. Of the total steam electric capacity, stand-alone steam turbines burning coal or petroleum coke account for 70 percent.

There are 281 generating units with a capacity of 50 MW or less (13 percent of all steam electric generating units); however, only 71 coal- or petroleum coke-fired generating units have a capacity of 50 MW or less (3.2 percent of all coal- or petroleum coke-fired generating units). The 281 generating units account for only 1.1 percent of the total capacity associated with the steam electric power generating industry.

[20] The overall plant capacity includes all electric power generated by the plant, including electricity produced using non-steam generators and non-fossil/non-nuclear energy sources.

Table 4-2. Distribution of Prime Mover Types for Plants Regulated by the Steam Electric Power Generating ELGs

Steam Electric Prime Movers	2009 EIA			Steam Electric Survey		
	Number of Plants [a]	Number of Electric Generating Units	Total Steam or Combined Cycle Turbine Capacity (MW)	Number of Plants [a]	Number of Electric Generating Units	Total Steam or Combined Cycle Turbine Capacity (MW)
Stand-Alone Steam Turbine	787 (67%)	1,868 (76%)	555,000 (71%)	716 (66%)	1,640 [b] (74%)	528,000 (71%)
Combined Cycle System [c]	438 (37%)	599 (24%)	224,000 (29%)	408 (38%)	573 (26%)	213,000 (29%)
Combined Cycle Steam Turbine [d]	416	550	81,100	408	573	87,700 [e]
Combined Cycle Single Shaft (steam and combustion turbines sharing a single shaft) [f]	22	49	9,570	-	-	-
Combined Cycle Combustion Turbine	411	1,013	134,000	404	570	125,000 [g]
Total	**1,179 (100%)**	**2,467 [g] (100%)**	**780,000 (100%)**	**1,079 [h] (100%)**	**2,214 [g] (100%)**	**741,000 (100%)**

Source: Steam Electric Survey [ERG, 2015a]; 2009 EIA [U.S. DOE, 2009].

Note: Capacity values are rounded to three significant figures.

Note: The number of plants, generating units, and capacity in the steam electric power generating industry generated from the Steam Electric Survey are based on reported values, which were scaled up to represent the industry as a whole using the industry-weighting factors discussed in Section 3.2.

a – Because a single plant may operate multiple electric generating units of various prime mover types, the number of plants by prime mover type is not additive. There are 1,179 plants (according to the 2009 EIA) or 1,079 plants (according to the Steam Electric Survey) in the industry that operate at least one steam electric generating unit powered by either fossil or nuclear fuel.

b – One generating unit operating a stand-alone steam turbine reported burning only wood. This unit is not included in the count of generating units because it does not meet the applicability of the Steam Electric Power Generating ELGs.

c – Due to the nature of the EIA data, EPA was able to identify the number of combined cycle turbines (*i.e.*, prime movers), but could not discern the number of actual combined cycle systems. EPA estimated the number of combined cycle systems reported in EIA by adding the number of combined cycle steam turbines and the number of single shaft turbines. Typically, there are multiple combustion turbines to a single steam turbine in a combined cycle system; therefore, EPA believes this methodology better represents the number of combined cycle systems than simply adding the number of combined cycle combustion and steam turbines. For the Steam Electric Survey data, the plants reported the combined-cycle-system-level information directly.

d – One plant in the 2009 EIA database reported using a fossil fuel for its combined cycle steam turbine and a non-fossil/non-nuclear fuel for its three combined cycle combustion turbines. EPA included the combined cycle steam turbine from this plant in the table, but did not include the combined cycle combustion turbines using fuels not covered by the ELGs.

e – From the Steam Electric Survey data, EPA was not able to categorize the combined cycle systems as a combined cycle steam turbine, a combined cycle single shaft, or a combined cycle combustion turbine. Seven plants (17 units) identified operating a combined cycle system but provided only the steam turbine capacity. The 2009 EIA data identifies these units as single-shaft turbines. The total capacity of these units, steam turbine and combustion turbine capacity, is accounted for under combined cycle steam turbines.

f – EIA data differentiate among types of combined cycle turbines, with a separate designation for single shaft turbines (steam and combustion turbines sharing a single shaft). EPA's Steam Electric Survey does not differentiate between types of combined cycle systems; single shaft turbines are included as combined cycle systems.

g – EPA estimated the total number of electric generating units as the sum of the stand-alone steam turbines and the estimated number of combined cycle systems. EPA did not sum the total number of turbines.

h – EPA identified another plant that began operation after the time period for the Steam Electric Survey, resulting in a total baseline population of 1,080 plants for the ELG analyses.

Table 4-3. Distribution of Fuel Types Used by Steam Electric Generating Units

Fossil or Nuclear Fuel [a]	Stand-Alone Steam Turbines			Combined Cycle Steam Turbines [b]		
	Number of Plants	Number of Electric Generating Units	Total Turbine Capacity (MW)	Number of Plants	Number of Electric Generating Units	Total Turbine Capacity (MW)
Coal:	*455-465*	*1,080-1,090*	*328,000-330,000*	*2*	*2*	*427*
Anthracite Coal	1	1	128	0	0	0
Bituminous Coal	209	497	144,000	1	1	101
Subbituminous Coal	145	310	109,000	0	0	0
Lignite Coal	10-15	10-20	7,000-8,000	0	0	0
Coal Synfuel	0	0	0	0	0	0
Waste/Other Coal	17	18	1,660	0	0	0
Blend [c]	106	240	66,700	1	1	326
Petroleum Coke	*8*	*11*	*751*	*1*	*1*	*334*
Oil:	*55-65*	*70-85*	*22,500-23,500*	*5-10*	*5-15*	*1,400-1,900*
No. 1 Fuel Oil	0	0	0	0	0	0
No. 2 Fuel Oil	1-5	1-5	200-300	0	0	0
No. 4 Fuel Oil	1	1	210	0	0	0
No. 5 Fuel Oil	0	0	0	0	0	0
No. 6 Fuel Oil	15-20	20-30	12,500-13,500	0	0	0
Diesel Fuel	3	3	1,480	4	7	438
Jet Fuel	0	0	0	0	0	0
Kerosene	0	0	0	1-5	1-5	1,000-1,500
Waste Oil/Other Oil	0	0	0	0	0	0
Blend [c]	32	46	8,430	0	0	0
Gas:	*171*	*367*	*71,500*	*400*	*562*	*210,000*
Natural Gas	171	367	71,500	395	556	210,000
Blast Furnace Gas	0	0	0	0	0	0
Gaseous Propane	0	0	0	0	0	0
Other Gases	0	0	0	0	0	0
Blend [c]	0	0	0	5	5	537

Table 4-3. Distribution of Fuel Types Used by Steam Electric Generating Units

Fossil or Nuclear Fuel [a]	Stand-Alone Steam Turbines			Combined Cycle Steam Turbines [b]		
	Number of Plants	Number of Electric Generating Units	Total Turbine Capacity (MW)	Number of Plants	Number of Electric Generating Units	Total Turbine Capacity (MW)
Nuclear	*66*	*99*	*104,000*	*0*	*0*	*0*
Total	**716 [d]**	**1,640**	**528,000**	**408 [d]**	**573**	**213,000**

Source: Steam Electric Survey [ERG, 2015a].

Note: Certain cells contain ranges of values to protect the release of information claimed confidential business information (CBI).

Note: Capacity values are rounded to three significant figures.

Note: The number of plants, units, and capacity in the steam electric power generating industry generated from the Steam Electric Survey are based on reported values, which were scaled up to represent the industry as a whole using the industry-weighting factors discussed in Section 3.2.

a – Units were first classified by fuel group based on the following hierarchy: coal, oil, gas, and nuclear. For example, if a unit burns both coal and gas then it was categorized as coal, even if coal was reported as generating less electricity compared to other fuel groups. Units were then categorized by the type of fuel burned.

b – The Steam Electric Survey identifies combined cycle systems, which include at least one steam turbine and one combustion turbine.

c – The 'blend' category identifies units that burn more than one type of fuel within the fuel group. For example, for a generating unit that burns coal, a blend coal unit burns at least two different types of coal.

d – Because a single plant may operate multiple electric generating units burning various types of fuel, the number of plants by fuel type is not additive. Of the plants that responded to the Steam Electric Survey, 716 plants reported operating at least one stand-alone steam turbine powered by either fossil or nuclear fuel and 408 plants reported operating at least one combined-cycle system powered by either fossil or nuclear fuel.

Table 4-4. Distribution by Size of Steam Electric Capacity and Plants Regulated by the Steam Electric Power Generating ELGs

	Overall Plant Capacity Range [a]						
	0-100 MW	100-200 MW	200-300 MW	300-400 MW	400-500 MW	>500 MW	Total
Total Steam Electric Capacity [b]	5,040	9,410	11,300	17,600	17,100	680,000	741,000
Percentage of Capacity	0.7%	1.3%	1.5%	2.4%	2.3%	91.8%	100%
Number of Plants	103	88	72	79	61	676	1,079 [c]
Percentage of Plants	9.6%	8.2%	6.6%	7.3%	5.7%	62.7%	100%

Source: Steam Electric Survey [ERG, 2015a].

Note: Capacity values are rounded to three significant figures.

Note: The number of plants and total steam electric capacity includes the stand-alone turbines and the combined cycle systems.

Note: The number of plants and capacity in the steam electric power generating industry are based on values reported in the Steam Electric Survey, which were scaled to represent the industry as a whole using the industry-weighting factors discussed in Section 3.2.

a – Overall plant steam electric capacity includes electricity produced by only steam electric generating units. Electricity generated by non-steam-electric generating units and those using non-fossil/non-nuclear energy sources is not included.

b – The capacity presented within each size distribution is based on the overall plant steam electric generating capacity.

c – EPA identified another plant that began operation after the time period for the Steam Electric Survey, resulting in a total baseline population of 1,080 plants for the ELG analyses.

Table 4-5. Distribution by Size of Steam Electric Generating Units Regulated by the Steam Electric Power Generating ELGs

	Unit Capacity Range [a]							
	0-50 MW	50-100 MW	100-200 MW	200-300 MW	300-400 MW	400-500 MW	>500 MW	Total
Total Steam Electric Capacity	8,010	23,200	65,700	62,200	72,200	55,700	454,000	741,000
Percentage of Capacity	1.1%	3.1%	8.9%	8.4%	9.7%	7.5%	61.3%	100%
Number of Steam Electric Generating Units	281	305	445	247	207	124	605	2,214
Percentage of Steam Electric Generating Units	12.7%	13.8%	20.1%	11.2%	9.3%	5.6%	27.3%	100%

Source: Steam Electric Survey [ERG, 2015a].

Note: Capacity values are rounded to three significant figures.

Note: The number of plants, number of steam electric generating units, and total steam electric capacity include the stand-alone turbines and the combined cycle systems.

Note: The number of units and capacity in the steam electric power generating industry are based on values reported in the Steam Electric Survey, which were scaled to represent the industry as a whole using the industry-weighting factors discussed in Section 3.2.

a – The capacity presented within each size distribution is based on the capacity at the unit level.

4.3 STEAM ELECTRIC WASTESTREAMS WITH NEW CONTROLS IN THE FINAL ELGS

This section describes the wastestreams generated by steam electric power plants for which EPA established new or revised discharge requirements for the ELGs. Section 4.4 discusses other wastestreams generated by the steam electric power generating industry for which EPA is not establishing new discharge requirements in the ELGs.

4.3.1 Fly Ash Transport Water

Depending on the boiler design, as much as 70 to 80 percent of the ash from a pulverized coal furnace consists of fly ash. Certain boiler designs, such as cyclone boilers, produce lesser amounts of fly ash, approximately 20 to 30 percent of the ash generated. Many plants transport fly ash from the particulate collection system (*i.e.*, collection hoppers) using water as the motive force, known as sluicing. This section presents an overview of fly ash transport water generated by the steam electric power generating industry.

As discussed in Section 4.2.1, flue gas contains entrained fly ash as it leaves the boiler. Steam electric generating units use three main particulate collection methods to remove fly ash from the flue gas: ESPs, baghouses, and venturi-type wet scrubbers. Of the approximately 1,100 coal-, petroleum coke-, and oil-fired units collecting fly ash, 97 percent utilize one of these three collection methods. These three collection methods are described below and Table 4-6 presents the number of coal- , petroleum coke-, and oil-fired units utilizing each of these collection methods.

Table 4-6. Fly Ash Collection Practices in the Steam Electric Power Generating Industry in 2009

Fly Ash Collection Method	Number of Plants	Number of Coal- and Petroleum Coke-Fired Steam Electric Units	Number of Oil-Fired Steam Electric Units
ESP	335	816	5-10
Baghouse	143	220	0
Baghouse and ESP	5-15	10-15	2
Wet Scrubber	5-15	15-25	0
Other	20	12	9
Total	**508-528 [a]**	**1,080-1,100 [a]**	**26-31**

Source: Steam Electric Survey [ERG, 2015a].

Note: Certain fields contain ranges of values to protect the release of information claimed CBI.

Note: The number of plants, units, and capacity in the steam electric power generating industry are based on values reported in the Steam Electric Survey, which were scaled to represent the industry as a whole using the industry-weighting factors discussed in Section 3.2.

a – Fifteen coal-fired generating units at nine plants identified no fly ash collection method. These plant and unit values are included in the count of total plants and units collecting fly ash only.

To remove the fly ash particles from the flue gas, many plants operate ESPs, which use high voltage to generate an electrical charge on the particles contained in the flue gas. The charged particles then collect on a metal plate with an opposite electric charge. Additionally, some plants may use agglomerating agents, such as ammonia, which help small charged ash particles form larger agglomerates that are more readily attracted to the charged plates, improving the removal efficiency of the ESPs. As the particles begin to layer on the metal plates, the plates are tapped/rapped to loosen the particles, which fall into collection hoppers. ESPs can remove 99.9 percent of fly ash from the flue gas [Babcock & Wilcox, 2005]. These types of systems are the most common type of fly ash collection system used in the steam electric power generating industry. Of the approximately 1,100 coal-, petroleum coke-, and oil-fired units in the industry that reported collecting fly ash in the Steam Electric Survey, about 830 units (75 percent) utilize an ESP system [ERG, 2015a].[21]

Plants may also use other particulate control technologies, such as baghouse filters. A baghouse system contains several compartments, each containing fabric filter bags that are suspended vertically in the compartment. The bags can be quite long (*e.g.*, 40 feet) and small in diameter [Babcock & Wilcox, 2005]. The reverse air system is the baghouse configuration most commonly used by steam electric power plants. In this system, the flue gas enters into the various compartments and is forced to flow into the bottom of the fabric filter bags. The flue gas passes through the fabric filter, but the fly ash particulates are captured on the inside walls of the baghouse. As the baghouses collect more particulates, the layer of particulates becomes thicker and helps to remove more particulates from the flue gas. After a specified period of time or once the pressure drop in the baghouse reaches a high set point, the plants reverse the flow in the compartments and send clean flue gas from the outside of the fabric filter bags to the inside, which dislodges the particulates. The particulates are captured in hoppers at the bottom of the compartment [Babcock & Wilcox, 2005]. Of the approximately 1,100 coal-, petroleum coke-, and oil-fired generating units that reported collecting fly ash from flue gas, about 235 units (22 percent) use baghouse filters [ERG, 2015a].[22]

After the ESP or baghouse deposits the fly ash into the hoppers, the plant can either handle the fly ash in a dry or wet fashion. In either system, dry fly ash is initially drawn away from the hoppers using a vacuum to pneumatically transport the ash. Plants operating a dry fly ash handling system pneumatically transfer the fly ash from the hopper to a fly ash storage silo and then dispose of the ash. Plants operating a wet fly ash handling system use water to transport the fly ash from the hopper to a surface impoundment. Section 7.2 discusses the different ash handling methods used in the steam electric power generating industry in more detail.

Additionally, between 15 and 25 generating units use venturi-type wet scrubbers to remove fly ash from the flue gas [ERG, 2015a]. Venturi scrubbers contain a tube with flared ends and a constricted middle section. The flue gas enters from one of the flared ends and approaches the constricted section. A liquid slurry stream is added to the scrubber just prior to or at the constricted section. As the flue gas enters the constricted section, its pressure and velocity increases, which causes the gas and liquid slurry to mix. The greater the pressure drop in the scrubber, the better the mixing and the better the reaction rate, which increases the particulate removal efficiency. However, venturi scrubbers must be operated at high pressure drops to

[21] This includes 10 to 15 generating units that use a combination system that incorporates an ESP and baghouse filters to remove particulates from the flue gas.

[22] This includes 10 to 15 generating units that use a combination system comprising an ESP and baghouse filters to remove particulates from the flue gas.

remove the same level of particulates as ESPs, making their operation costs higher than ESPs [Babcock & Wilcox, 2005]. EPA does not consider the ash collected by venturi-type wet scrubbers as fly ash, and therefore, the water generated by these systems is not considered fly ash transport water.

Table 4-7 presents the fly ash handling practices used by plants operating coal-, petroleum coke-, and oil-fired generating units. In 2009, approximately one-third of the coal- and petroleum-fired generating units handled at least a portion of their fly ash with a wet-sluicing system. A small percentage (about 20 percent) of oil-fired units also handled at least a portion of their fly ash with a wet-sluicing system. In most cases, plants manually remove the fly ash from these oil-fired units by methods such as scraping the ash out of the boiler. In general, oil-fired units produce much less fly ash than coal-fired units. For example, oil-fired units responding to the Steam Electric Survey produced an average of just over 60 tons of fly ash per year per unit, compared to over 60,000 tons per year for an average coal-fired unit.

Table 4-7. Fly Ash Handling Practices in the Steam Electric Power Generating Industry

Fly Ash Handling	Number of Plants	Coal- and Petroleum Coke-Fired Steam Electric Units		Oil-Fired Steam Electric Units	
		Number of Units	Capacity (MW)	Number of Units	Capacity (MW)
Wet-Sluiced	57 (11%)	205	47,000 (14%)	10-15	7,500-10,000 (33%)
Handled Dry or Removed in Scrubber [a]	344 (67%)	713	222,000 (67%)	10-15	2,500-5,000 (17%)
Handled Either Wet or Dry [b]	81 (16%)	168	59,000 (18%)	1-5	500-1,500 (3%)
No Handling System Reported	32 (6%)	10	2,370 (1%)	61	11,400 (44%)
Total	**514**	**1,096**	**330,000**	**80-95**	**21,900-27,900**

Source: Steam Electric Survey [ERG, 2015a].

Note: Certain fields contain ranges of values to protect the release of information claimed CBI.

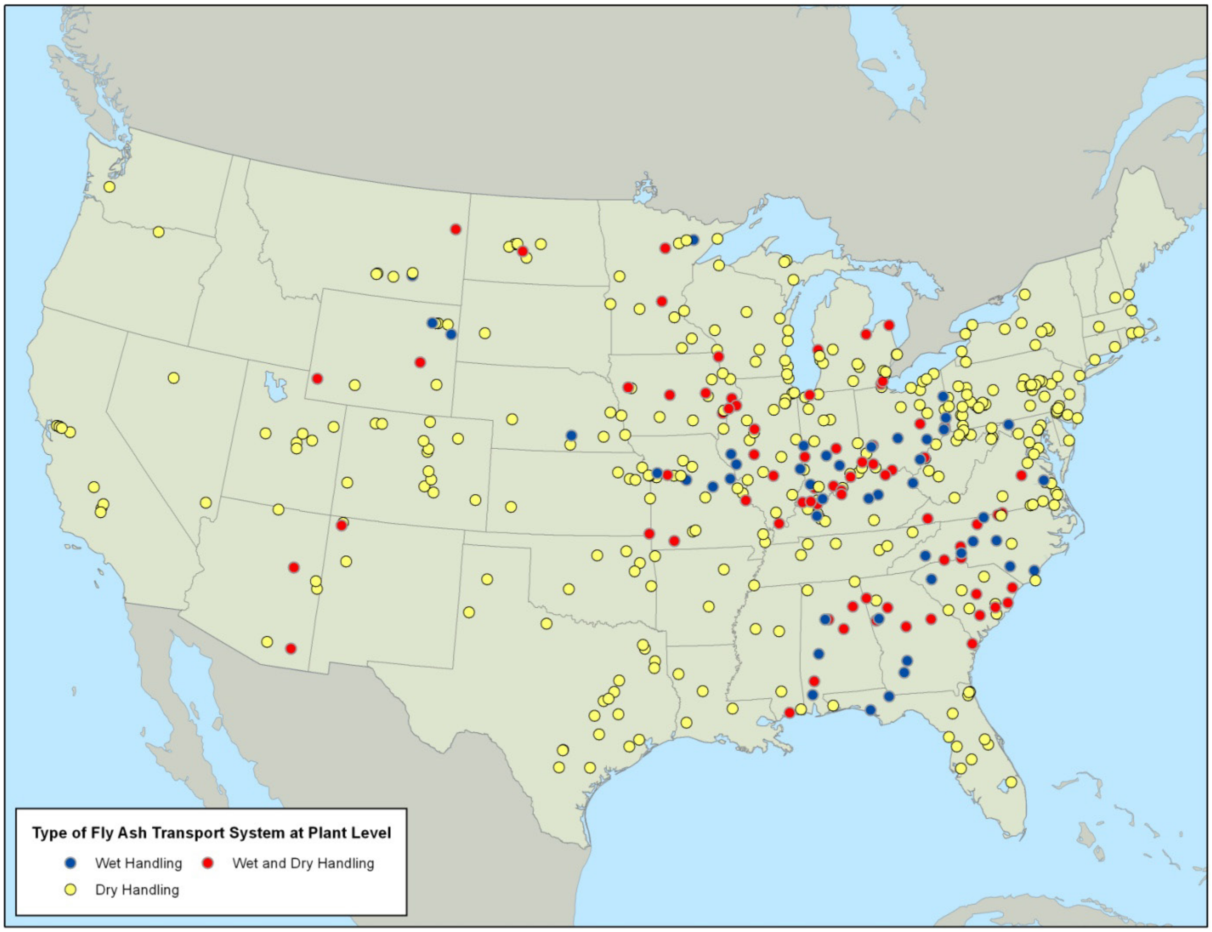
Note: Capacity values are rounded to three significant figures.

Note: The number of plants, units, and capacity in the steam electric power generating industry are based on values reported in the Steam Electric Survey, which were scaled to represent the industry as a whole using the industry-weighting factors discussed in Section 3.2.

a – EPA considered all transport methods other than wet sluicing as dry fly ash transport.

b –These units have both wet and dry handling systems for removing fly ash from the boiler and can operate either system as needed.

Most plants operating wet fly ash handling systems are located east of the Mississippi River. Figure 4-5 provides a distribution of the three categories of fly ash handling practices presented in Table 4-7. Each symbol represents the plant-level fly ash handling system. The figure includes only the plants that provided responses to the Steam Electric Survey (*i.e.*, the figure does not represent the weighted numbers). Plants categorized as 'wet and dry handling' operate some units at the plant with wet fly ash handling systems and other units with dry fly ash handling systems, or in some instances operate both a wet and a dry fly ash handling system for an individual generating unit.



Source: Steam Electric Survey [ERG, 2015a].

Figure 4-5. Plant-Level Fly Ash Handling Systems in the Steam Electric Power Generating Industry in 2009

In 1982, EPA promulgated new source performance standards (NSPS) that prohibited new sources from discharging wastewater pollutants in fly ash transport water. Not surprisingly, EPA has found that the steam electric units generating fly ash transport water tend to be older units (*e.g.*, more than 30 years old), while most units built since the NSPS were promulgated are outfitted with dry fly ash handling systems.

From the Steam Electric Survey data, EPA identified 45 to 55 plants that have installed dry fly ash handling systems, either to replace the current wet handling system or to operate as a parallel system, between 2000 and 2009. Table 4-8 presents the number of generating units that converted from wet fly ash handling to dry fly ash handling between 2000 and 2009 identified in the Steam Electric Survey. Each plant and generating unit is classified by the type of dry system installed, which include wet vacuum pneumatic systems, dry vacuum systems, pressure systems, and combined vacuum and pressure systems. Each of these dry fly ash handling systems is described in Section 7. Data from the Steam Electric Survey show that, as of 2009, power companies converted at least 85 generating units at over 45 plants to dry fly ash handling systems since 2000. Power companies also reported in the Steam Electric Survey that they are planning to convert an additional 61 generating units to dry handling systems by the year 2020. The reasons cited for installing the dry handling systems include environmental remediation (*i.e.*, discharges from the fly ash impoundments caused environmental impacts), economic opportunity (*e.g.*, revenues from sale of fly ash), and the need to replace ash impoundments approaching full storage capacity. 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. In addition, it reduces the amount of intake water the plant uses and eliminates the need for an impoundment to store the fly ash transport water. Section 6.2 presents additional information on the amount of fly ash transport water generated and discharged by the steam electric power generating industry and the pollutant characteristics of the transport water.

Table 4-8. Conversions of Wet Fly Ash Sluicing Systems Between 2000 and 2009

Type of Dry Fly Ash Handling System Installed	Number of Plants	Number of Units	Capacity (MW)
Wet Vacuum System (pneumatic) [a]	1-5	1-5	2,000-3,000
Dry Vacuum System [b]	24	50	9,400
Pressure System [c]	5-10	15-25	7,500-10,000
Combined Vacuum/Pressure System [d]	18	36	15,800
Total [e]	**45-55 (35-42%)**	**85-115 (26-35%)**	**34,700-38,200 (38-42%)**

Source: Steam Electric Survey [ERG, 2015a].

Note: Certain fields contain ranges of values to protect the release of information claimed CBI.

Note: Capacity values are rounded to three significant figures.

Note: The number of plants, units, and capacity in the steam electric power generating industry are based on values reported in the Steam Electric Survey, which were scaled to represent the industry as a whole using the industry-weighting factors discussed in Section 3.2.

Note: Approximately 33 of these units also wet sluiced a portion of the fly ash in 2009.

a – One of these units also wet sluiced a portion of the fly ash in 2009.

b – Twelve of these units also wet sluiced a portion of the fly ash in 2009.

c – Four of these units also wet sluiced a portion of the fly ash in 2009.

d – Sixteen of these units also wet sluiced a portion of the fly ash in 2009.

e – The percentages are based on the number of systems conducting any wet-sluicing operations (wet-sluicing systems and wet and dry systems) in 2000 prior to any conversions (excluding units that have retired since that time).

4.3.2 Bottom Ash Transport Water

As much as 70 to 80 percent of the ash from a pulverized coal furnace consists of fly ash. The remaining 20 to 30 percent is bottom ash. Cyclone boilers, and other boiler designs, can produce a larger percentage of bottom ash, upwards of 70 to 80 percent. Like fly ash, bottom ash can be transported from the boiler using water. This section presents an overview of bottom ash transport water generated by the steam electric power generating industry.

Heavy bottom ash particles collect in the bottom of the boiler. The sloped walls and opening at the bottom of the boiler allow the bottom ash to feed by gravity to the bottom ash hoppers positioned below the boiler. The bottom ash hoppers are connected directly to the boiler bottom to prevent any gases from leaving the boiler. Depending on the size of the boiler, there may be more than one hopper running along the opening of the bottom of the boiler. Most bottom ash hoppers are filled with water to quench the hot bottom ash as it enters the hopper. Once the hoppers have filled with bottom ash, a gate at the bottom of the hopper opens and the ash is directed to grinders to grind the bottom ash into smaller pieces. From the hopper, bottom ash can be handled in a wet or dry fashion.

Plants operating a wet bottom ash handling system sluice the bottom ash with water to an impoundment or a dewatering bin. Because bottom ash particles are heavier than fly ash particles, they more easily separate from the transport water. Some plants operate large surface impoundments for bottom ash, while others use a system of relatively small impoundments operating in series and/or parallel. Other plants operate dewatering bin systems, in which they use a tank-based settling operation to separate the bottom ash solids from the transport water. A dewatering bin system generally consists of at least two bins; while one bin is receiving bottom ash, the other bin is decanting the water from the collected bottom ash material. Excess water in the bin flows over a weir, leaving the dewatering bin. Plants can reuse this overflow water directly as bottom ash transport water, send it to an ash impoundment for additional settling, or discharge it directly to surface water. Some plants operating wet bottom ash handling systems can operate as closed-loop systems. These plants completely recycle the bottom ash transport water from impoundments, dewatering bins, or other handling systems back to the wet-sluicing system.

Most coal and petroleum coke plants operate wet bottom ash handling systems, as described above; however, a substantial number of plants operate a completely dry bottom ash handling system or a system that does not generate ash transport water (*e.g.*, mechanical drag system). As seen in Table 4-9, 112 plants handled at least a portion of their bottom ash dry in 2009.[23] These 112 plants represented 22 percent of plants operating a coal-, petroleum coke-, or oil-fired generating unit. Approximately 20 percent of all coal- and petroleum coke-fired generating units use dry bottom ash handling systems. The most common type of dry ash handling system used in the steam electric power generating industry is the mechanical drag chain system. The plant uses a drag chain to remove the bottom ash out of the boiler. The bottom ash is dewatered as the drag chain pulls the bottom ash up an incline, draining the water back to the boiler. The plant then conveys the bottom ash to a nearby collection area from which it is loaded onto trucks and either sold for beneficial use or stored on site in a landfill. Section 7.3 provides more detail on dry and closed-loop recycle bottom ash handling systems.

[23] For the purpose of this discussion, dry bottom ash handling systems includes all systems that do not generate bottom ash transport water; these include completely dry bottom ash handling systems, mechanical drag systems, and other mechanical removal systems (*e.g.*, scraping of bottom ash from boiler). Although a mechanical drag system may be used at a boiler that uses water in a quench bath to cool bottom ash, water is not used to transport the ash and thus it is considered, for the purpose of this report and the ELGs, to be a "dry" bottom ash system. Complete recycle and remote mechanical drag systems that use water to transport ash as part of the process are considered wet-sluicing systems.

Table 4-9. Bottom Ash Handling Practices in the Steam Electric Power Generating Industry

Bottom Ash Handling	Number of Plants	Coal- and Petroleum Coke-Fired Steam Electric Units: Number of Units	Coal- and Petroleum Coke-Fired Steam Electric Units: Capacity (MW)	Oil-Fired Steam Electric Units: Number of Units	Oil-Fired Steam Electric Units: Capacity (MW)
Wet-Sluiced	319 (62%)	863	286,000 (87%)	0-5	0-250 (1%)
Handled Dry [a]	142 (28%)	214	39,900 (12%)	30-35	10,000-15,000 (51%)
Handled Either Wet or Dry	26 (5%)	6	2,610 (1%)	0	0
No Handling System Reported	29 (5%)	12	1,400 (<1%)	57	11, 500 (48%)
Total	**516**	**1,096**	**330,000**	**80-95**	**21,900-27,900 [b]**

Source: Steam Electric Survey [ERG, 2015a].

Note: Certain fields contain ranges of values to protect the release of information claimed CBI.

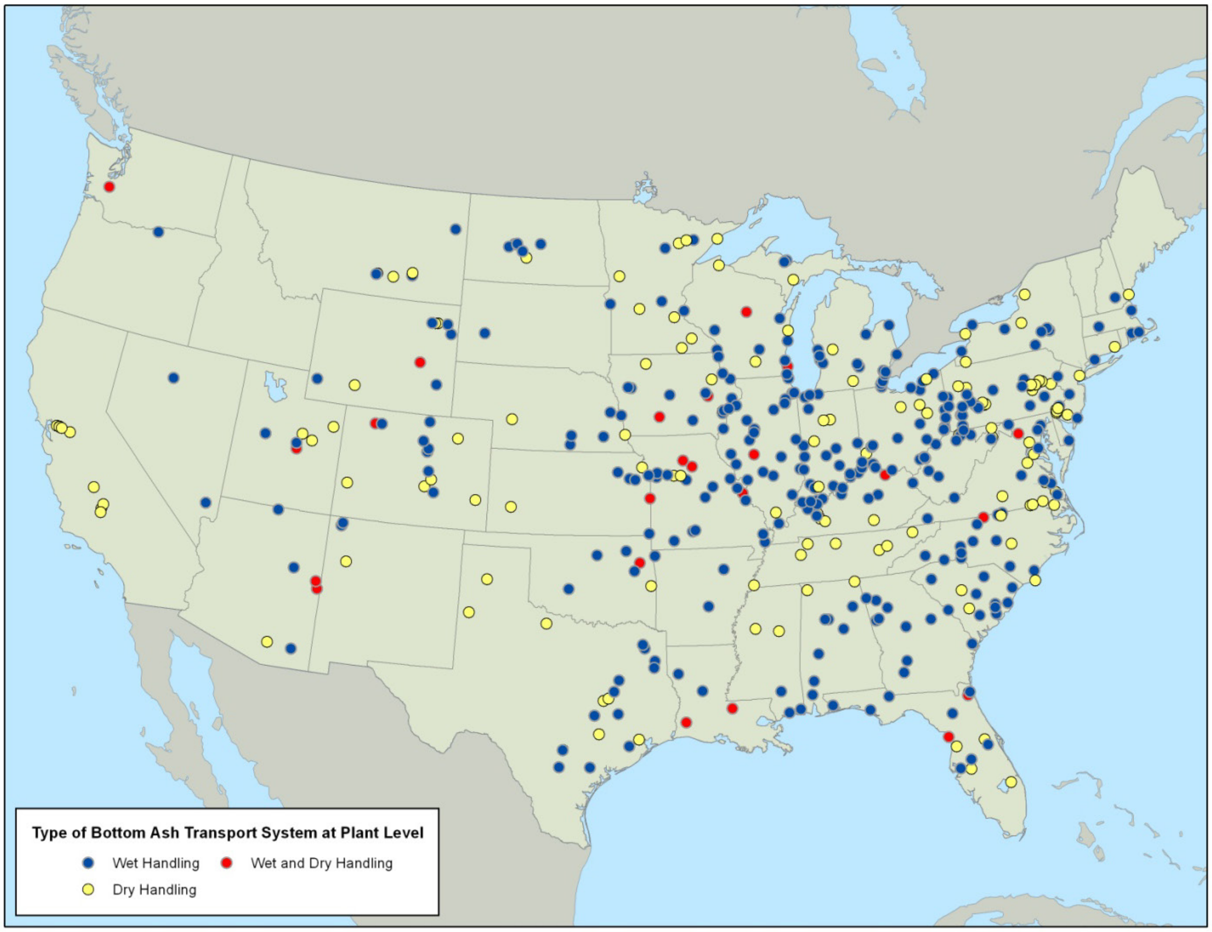
Note: Capacity values are rounded to three significant figures.

Note: The number of plants, units, and capacity in the steam electric power generating industry are based on values reported in the Steam Electric Survey, which were scaled to represent the industry as a whole using the industry-weighting factors discussed in Section 3.2.

a – Dry bottom ash handling systems include all systems that do not generate bottom ash transport water; these include completely dry bottom ash handling systems, mechanical drag systems, and other mechanical removal systems (*e.g.*, scraping of bottom of boiler).

b – Total capacity does not include the capacity of three oil units that did not report generating bottom ash.

Table 4-9 shows that 67 percent of plants (79 percent of coal- and petroleum coke-fired generating units) wet sluice all or part of the bottom ash produced. Figure 4-6 shows all plants producing bottom ash in 2009 in the United States with the type of bottom ash handling system identified by different colored symbols. The figure includes only the plants that responded to the Steam Electric Survey (*i.e.*, the figure does not represent the weighted numbers).



Source: Steam Electric Survey, [ERG, 2015a].

Figure 4-6. Plant-Level Bottom Ash Handling Systems in the Steam Electric Industry

Table 4-10 presents the 12 to 25 plants within the industry that converted wet-sluicing bottom ash operations between 2000 and 2009, from Steam Electric Survey data. The generating units and plants are classified by type of dry system installed. Steam electric power plants use mechanical drag systems, dry vacuum systems, dry pressure systems, or a handful of other dry handling methods. Each of these handling technologies is discussed further in Section 7. These generating units represent approximately 3 percent of the total number of steam electric generating units that were wet-sluicing bottom ash in 2000. In Steam Electric Survey data, power companies reported plans to convert an additional 67 generating units to dry or closed-loop recycle bottom ash handling systems by the year 2020.

Bottom ash transport water is typically directed to an on-site ash impoundment for treatment, as described earlier in this section. Steam electric generating units generate this water intermittently; the frequency depends upon hopper size and the operation of the boiler. Section 6.2 discusses in more detail the amount of bottom ash transport water generated and discharged by the steam electric power generating industry and the pollutant characteristics of the transport water.

Table 4-10. Conversions of Bottom Ash Sluicing Systems Between 2000 and 2009

Type of Dry Bottom Ash Handling System Installed	Number of Plants	Number of Units	Capacity (MW)
Mechanical Drag System	10-15	15-20	6,500-7,500
Dry Vacuum System	1-5	5-10	250-500
Dry Pressure System	0	0	0
Other	1-5	1-5	100-300
Total [a]	**12-25 (3-7%)**	**21-35 (2-4%)**	**6,850-8,300 (3%)**

Source: Steam Electric Survey [ERG, 2015a].

Note: Certain fields contain ranges of values to protect the release of information claimed CBI.

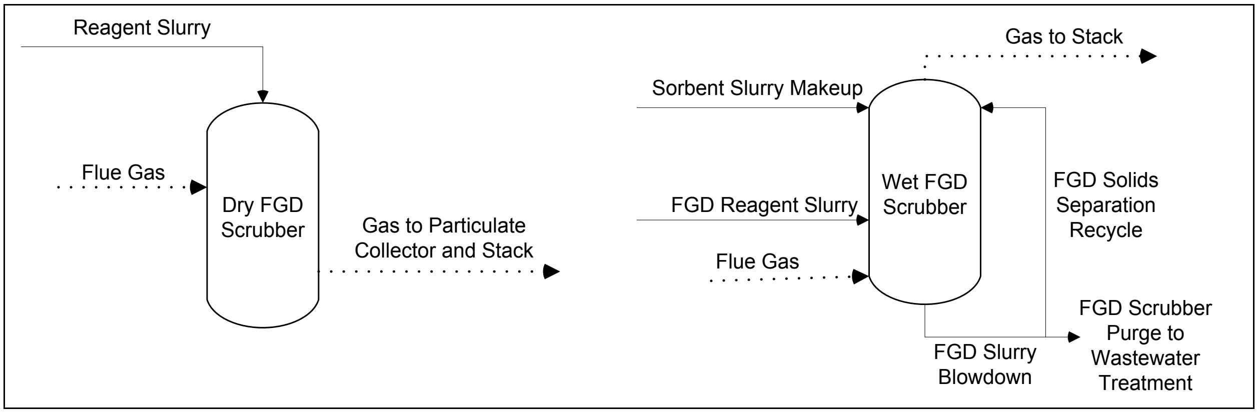
Note: Capacity values are rounded to three significant figures.

Note: The number of plants, units, and capacity in the steam electric power generating industry generated from the Steam Electric Survey are based on reported values, which were scaled to represent the industry as a whole using the industry-weighting factors discussed in Section 3.2

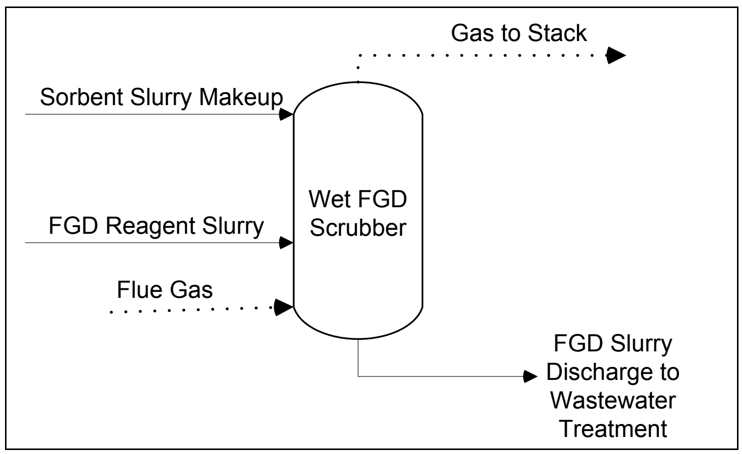
a – The percentages are based on the number of systems conducting any wet-sluicing operations (wet-sluicing systems and wet and dry systems) in 2000 (excluding units that have retired since that time).

4.3.3 Flue Gas Desulfurization Wastewater

To meet air quality requirements, many coal- and petroleum coke-fired steam electric power plants use a variety of FGD scrubber systems to control SO_2 emissions from flue gas generated in the plant's boiler. These systems are classified as "wet" or "dry." For the purposes of this rulemaking, "wet" FGD systems are those that use a sorbent slurry and that generate a water stream that exits the FGD scrubber absorber. Figure 4-7 presents a simplified diagram of typical wet and dry FGD systems.



Dry FGD System **Recirculating Wet FGD System**



Once-Through Wet FGD System

Figure 4-7. Typical FGD Systems

In dry FGD scrubbers, alkaline reagent slurry is introduced into the hot flue gas stream. The slurry passes through an atomizer and enters the scrubber as a fine mist of droplets. In the scrubber, SO_2 is absorbed as the slurry is evaporated and the flue gas is cooled. Dry FGD scrubbers typically remove between 80 and 90 percent of the SO_2, which is less than a wet FGD system. The amount of water in the reagent slurry is controlled such that it evaporates almost completely in suspension [Babcock & Wilcox, 2005]. Although dry FGD scrubbers use water in their operation, the water in most systems evaporates and they generally do not discharge wastewater. Of the 72 dry FGD plants, 23 generate wastewater during operation and only two discharge to a surface water. Wastewater may also be generated during cleaning operations. Of the 72 dry FGD plants, 31 generate wastewater from cleaning operations and only four discharge any cleaning wastewater [ERG, 2015a]. Dry FGD systems generate smaller, less frequent quantities of wastewater from their operation/cleaning compared to the FGD wastewater from wet systems. EPA did not evaluate the wastewater generated from these dry FGD systems as part of the rulemaking and they would not be subject to the FGD wastewater requirements in the ELGs.

Wet FGD scrubber systems can remove over 90 percent, and in some cases up to 99 percent, of the SO_2 in the flue gas. In wet FGD scrubbers, the flue gas stream contacts a liquid stream containing a sorbent, which causes the mass transfer of pollutants from the flue gas to the liquid stream. The sorbents typically used for SO_2 absorption are lime ($Ca(OH)_2$) or limestone ($CaCO_3$), which react with the sulfur in the flue gas to form calcium sulfite ($CaSO_3$). Scrubbers can be operated with forced, inhibited, or natural oxidation systems. In forced oxidation systems, the $CaSO_3$ is fully oxidized to produce gypsum ($CaSO_4 \bullet 2H_2O$). During the scrubbing process, metals and other constituents that were not removed from the flue gas stream by the ESPs may transfer to the scrubber slurry and leave the FGD system via the scrubber blowdown (*i.e.*, the slurry stream exiting the FGD scrubber that is not immediately recycled back to the spray/tray levels). The scrubber blowdown is typically intermittently transferred from the FGD scrubber to the solids separation process. As a result, FGD scrubber purge (*i.e.*, the wastestream from the FGD scrubber system that is transferred to a wastewater treatment system or discharged) is also usually intermittent [ERG, 2015a].

Table 4-11 presents the distribution of wet and dry current and planned FGD systems based on plant reported data in the Steam Electric Survey. Table 4-12 shows the *total scrubbed capacity* of the steam electric generating units serviced in those systems.[24] There are 401 current and planned FGD systems, servicing 458 coal-fired steam electric generating units.[25] Of these 401 systems, 311 generate a slurry stream and are considered "wet" FGD systems for the purposes of this rulemaking. Wet FGD systems service 78 percent of scrubbed generating units, representing 84 percent of the total industry scrubbed capacity. These wet systems typically use a limestone slurry with forced oxidation and service generating units burning bituminous coal. Often, plants also operate SCR systems on these generating units to control NO_x emissions.

Steam electric power plants operating wet FGD systems are located throughout the United States; the largest number is on the eastern United States where more bituminous coal-fired steam electric power plants are located. Figure 4-8 shows the location of all wet scrubbed FGD systems located at the plants noted in Table 4-12. The figure includes only the plants that provided responses to the Steam Electric Survey (*i.e.*, the figure does not represent the weighted numbers).

[24] The total scrubbed capacity includes electric power generated by only those steam electric generating units serviced by an FGD system.

[25] EPA incorporated company-verified steam electric generating unit retirements, fuel conversions, and wastewater treatment upgrades prior to implementation of final rule in EPA's analyses, compliance cost estimates, and pollutant loadings for the ELGs (see Section 4.5).

Table 4-11. Types of FGD Scrubbers in the Steam Electric Power Generating Industry

Type of Scrubber	"Wet" FGD Systems		"Dry" FGD Systems	
	Number of Plants	Number of Electric Generating Units	Number of Plants	Number of Electric Generating Units
Circulating Dry	0	0	11	11
Jet Bubbling Reactor	10-15	30-40	0	0
Mechanically Aided	0	0	1	1
Packed	2	4	1	2
Spray	77	159	1-5	1-5
Spray/Tray	58	118	0	0
Spray Dryer	1	1	50	69
Tray	1	1	0	0
Venturi	10	23	1-5	1-5
Other [a]	7	15	5-10	7-12
No Information [b]	2	2	0	0

Source: Steam Electric Survey [ERG, 2015a].

Note: Certain fields contain ranges of values to protect the release of information claimed CBI.

Note: A plant may operate multiple electric generating units that may use different types of FGD systems; therefore, the sum of plants may be greater than the total number of plants with FGD systems.

a – The types of scrubber systems classified as 'other' include Advatech Double contact flow scrubbers and dry sodium injection scrubbers.

b – Insufficient information is available to classify these units/plants in a specific category.

Table 4-12. Characteristics of Coal- and Petroleum Coke-Fired Generating Units with FGD Systems

	Wet FGD Systems			Dry FGD Systems		
	Number of Plants	Number of Electric Generating Units	Scrubbed Capacity [a] (MW)	Number of Plants	Number of Electric Generating Units	Scrubbed Capacity [a] (MW)
Total	**150**	**357**	**176,000**	**72**	**99**	**32,200**
Coal Type						
Bituminous	86	200	102,000	28	40	8,610
Subbituminous	28	63	33,400	29	40	16,900
Lignite	7	9	5,330	2	3	1,320
Petroleum Coke	1	1	184	0	0	0
Other/Waste Coal	0	0	0	1	1	585
Blend [b]	32	80	32,800	8	10	1,870
No Information [c]	4	4	2,420	5	5	2,850
Type of Oxidation System						
Forced Oxidation	113	272	136,000	3	4	851

Table 4-12. Characteristics of Coal- and Petroleum Coke-Fired Generating Units with FGD Systems

	Wet FGD Systems			Dry FGD Systems		
	Number of Plants	**Number of Electric Generating Units**	**Scrubbed Capacity [a] (MW)**	**Number of Plants**	**Number of Electric Generating Units**	**Scrubbed Capacity [a] (MW)**
Inhibited Oxidation	17	34	19,600	2	3	1,480
Natural Oxidation	25	51	19,900	5	10	2,310
No Information or NA [d]	3	4	1,220	62	82	27,500
Sorbent						
Lime	12	29	9,340	56	73	24,500
Limestone	122	286	144,000	14	20	6,660
Magnesium-Enhanced Lime	13	29	15,900	0	0	0
Magnesium Oxide	1	2	740	0	0	0
Soda Ash	3	9	1,870	0	0	0
Sodium Hydroxide	1	2	277	0	0	0
Other	5	12	6,030	14	24	6,380
No Information [d]	4	6	3,670	0	0	0
NO_x Controls [e]						
SCR	97	201	116,000	27	32	13,200
SNCR	13-23	35-40	11,500-12,500	12	14	4,070
None/Other (no SCR/SNCR)	58	113	46,300	30-40	45-50	13,500-14,000
No Information [d]	2	2	900	5	5	1,250

Source: Steam Electric Survey [ERG, 2015a].

Note: Certain fields contain ranges of values to protect the release of information claimed CBI.

Note: Capacity values are rounded to three significant figures.

Note: All 150 wet scrubbed plants and 72 dry scrubbed plants are included in each of the categories presented in this table. Because a plant may operate multiple electric generating units that may represent more than one type of operation in each specific category, the sum of the plants, units, and capacity for each category may be greater than the total.

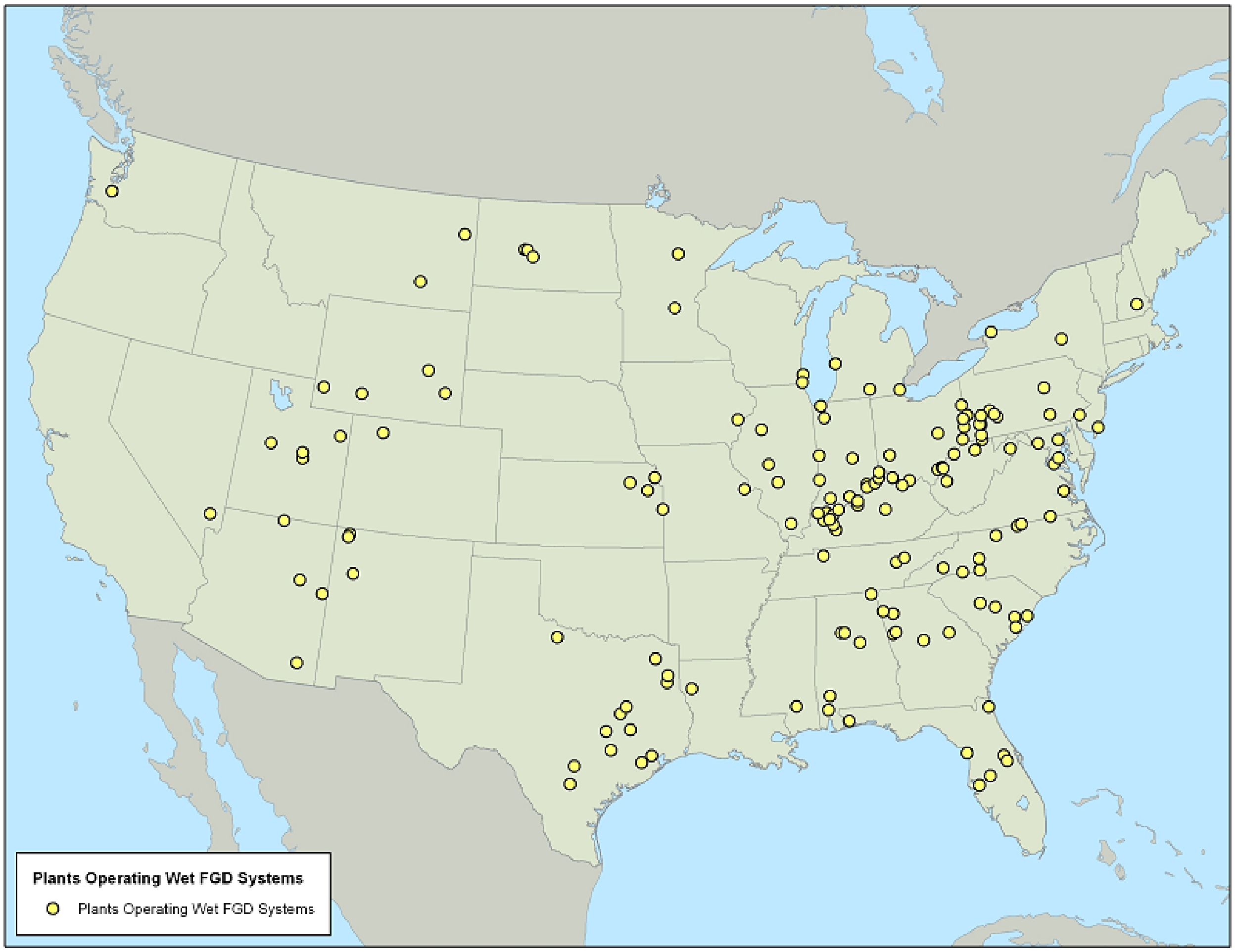
a – The scrubbed capacities represent the reported nameplate capacity for only those units serviced by a scrubber.

b – A coal blend is any combination of two or more different types of coal.

c – The current profile includes planned units whose coal type is not yet available.

d – Insufficient information is available to classify these units/plants in a specific category.

e – Some of the NO_x information included in this category is associated with NO_x systems that are planned or under construction.

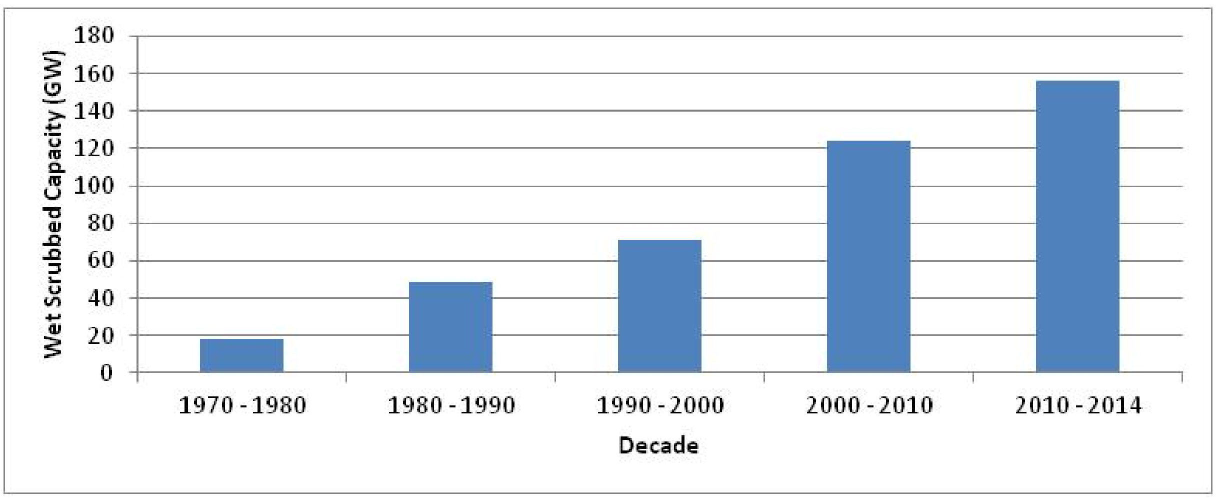


Source: Steam Electric Survey [ERG, 2015a].

Figure 4-8. Plants Operating Wet FGD Scrubber Systems in the Steam Electric Power Generating Industry in 2009

As shown in Table 4-12, limestone forced oxidation systems are the most common scrubbers reported in the Steam Electric Survey. Plants that generate gypsum using limestone forced oxidation systems can market the gypsum for use in building materials (*e.g.*, wallboard), while plants that do not generate gypsum or only partially oxidize the $CaSO_3$ must dispose of their scrubber solids, typically in landfills or impoundments [U.S. EPA, 2006]. Plants that produce a saleable product, such as gypsum, may rinse the product cake to reduce the level of chlorides in the final product and reuse or potentially treat and discharge the wash water along with the FGD scrubber purge. Both sludge by-products (gypsum and $CaSO_3$) typically require dewatering prior to sale, disposal, or processing for reuse. The dewatering process used by plants that generate $CaSO_3$ typically consists of thickeners used in conjunction with centrifuges. The dewatering process used by plants that generate gypsum typically consists of hydrocyclones used in conjunction with vacuum filters (either drum or belt). Additionally, some plants may send the FGD blowdown directly to a pond where the FGD solids are scooped out of the pond with a backhoe and stacked on the side of the pond (referred to as "stacking"). The stacking operation is more commonly used by plants generating gypsum, whereas most plants sending FGD wastewater with $CaSO_3$ just let the solids accumulate in the pond. These dewatering processes generate a wastewater stream that the plant likely needs to treat before it is discharged or reused. Plants that send the FGD blowdown directly to a pond typically do not use any other treatment prior to discharging the blowdown. Section 6.1 provides more detail on the amount of FGD wastewater generated by wet FGD systems.

The installation of wet FGD systems reported in Table 4-13 dates back to 1972. Figure 4-9 shows the total scrubbed capacity of wet FGD systems by decade starting with the 1970s. The figure includes all 311 wet current and planned FGD systems, but it does not include retired units that may have operated with wet FGD systems. Therefore, while the Steam Electric Survey shows an increase in the total wet scrubbed capacity from 1970 to 2010 of 123,000 MW, the actual increase may not be as large because the wet scrubbing capacity for earlier years for retired units may not be fully represented in the data set. However, based on discussions with industry representatives, EPA found that most power companies installed the FGD systems on the largest and newest generating units in their fleets, which are the generating units that are least likely to retire. Therefore, EPA believes that the amount of scrubbed capacity that has been retired over this 45-year period is likely minimal. If that is the case, then the data reasonably reflect the increased use of wet scrubbed FGD systems over the last 45 years.



Source: Steam Electric Survey [ERG, 2015a].

Figure 4-9. Capacity of Wet Scrubbed Units by Decade

Section 6.1 contains information on FGD wastewater characteristics and treatment.

4.3.4 Flue Gas Mercury Control Wastewater

In response to recent Clean Air Act (CAA) rules and other state regulations requiring limits on air emissions of mercury and other air toxics, plants are beginning to install new systems to improve removals of mercury from flue gas emissions, beyond those previously achieved by particulate control systems to remove fly ash. These systems are relatively new to the steam electric power generating industry. According to responses to the Steam Electric Survey, there are generally two types of systems being used to control flue gas mercury emissions:

- Adding oxidizing agents to the coal prior to combustion, so that the wet FGD system removes the oxidized mercury.
- Injecting activated carbon into the flue gas, which adsorbs the mercury so that it is captured in a downstream particulate removal system.

Using the oxidizing agents does not generate a new wastewater stream. However, the activated carbon injection system can generate a new wastestream at a plant, depending on the location of the injection. If the injection occurs upstream of the primary particulate removal system, then the mercury-containing carbon (*i.e.*, FGMC waste) will be collected and handled the same way as the fly ash; therefore, if the fly ash is wet-sluiced, then the FGMC wastes are also wet-sluiced. See Section 6.4 for more detail on how adding FGMC waste affects the characteristics of fly ash. If the injection occurs downstream of the primary particulate removal system, then the plant will use a secondary particulate removal system, typically a fabric filter, to capture the FGMC wastes. Plants typically inject the carbon downstream of the primary particulate collection system if they plan to market the fly ash because adding the FGMC wastes makes the fly ash unmarketable. In this situation, the FGMC wastes, which would be collected with some carry-over fly ash, could be handled either wet or dry.

Based on the responses to the Steam Electric Survey, there were approximately 120 installed FGMC systems as of 2009, with an additional 40 new installations planned. Approximately 90 percent of those installed FGMC systems are dry systems that do not generate or affect any wastewater streams. Approximately 6 percent of the current operating systems are wet systems. The type of handling system (*e.g.*, wet or dry handling) is unknown for the remaining 4 percent of the systems because they were planned FGMC systems at the time of the Steam Electric Survey.[26]

4.3.5 Landfill and Impoundment Combustion Residual Leachate

Combustion residuals comprise a variety of wastes from the combustion process, including fly ash and bottom ash from coal-, petroleum coke- or oil-fired units; FGD solids (*e.g.*, gypsum and calcium sulfite); FGMC wastes; and wastewater treatment solids associated with fuel combustion wastewater. Combustion residuals may be stored at the plant in on-site landfills or impoundments. When a landfill or impoundment has reached its capacity, it may be closed (*i.e.*, covered) to protect against environmental release of the pollutants contained in the waste. However, these landfills or impoundments may continue to generate combustion residual leachate.

Combustion residual leachate is leachate from landfills or surface impoundments containing combustion residuals. Leachate is composed of liquid, including any suspended or dissolved constituents in the liquid, that has percolated through or drained from waste or other materials emplaced in a landfill, or that passes through the surface impoundment's containment structure (*e.g.*, bottom, dikes, berms). Combustion residual leachate includes seepage and/or

[26] EPA did not estimate incremental compliance costs for FGMC wastewater because, as described in Section 9.2.6, EPA determined that all plants operating sorbent injection systems to remove mercury from the flue gas already operate dry handling systems, operate wet systems that do not discharge, or have the capability to operate dry handling systems.

leakage from a combustion residual landfill or impoundment unit. Combustion residual leachate includes wastewater from landfills and surface impoundments located on non-adjoining property when under the operational control of the permitted facility. Figure 4-10 presents a diagram depicting the generation and collection systems for landfill combustion residual leachate and stormwater. The two sources of landfill combustion residual leachate are precipitation that percolates through the waste deposited in the landfill and the liquids produced from the combustion residual placed in the landfill. Section 6.3 further discusses the characteristics of leachate.

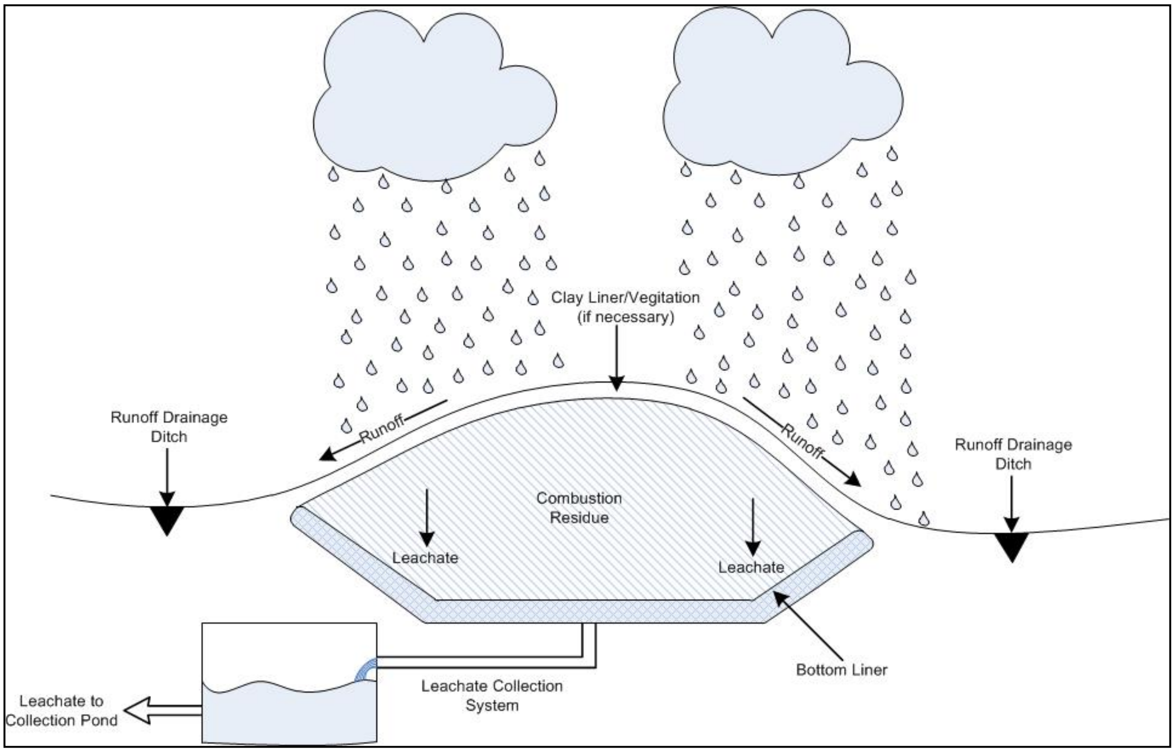


Figure 4-10. Diagram of Landfill Combustion Residual Leachate Generation and Collection

In a lined landfill, the combustion residual leachate collected from the landfill typically flows through a collection system consisting of ditches and/or underground pipes. From the collection system, the plant transports the combustion residual leachate to a collection impoundment. The stormwater collection systems typically consist of one or more small collection impoundments surrounding the landfill area. Plants may collect the combustion residual leachate and stormwater in separate impoundments or combine them together in the same impoundment(s). Some plants discharge the effluent from these collection impoundments, while other plants send the collection impoundment effluent to the ash impoundment. Sixty-three percent of the combustion residual landfills reported in the Steam Electric Survey are lined. Impoundments may also have liners and collection systems similar to the landfills; 51 percent of the combustion residual impoundments reported in the Steam Electric Survey are lined. Unlined impoundments and landfills do not collect combustion residual leachate migrating away from the impoundment/landfill, which can potentially contaminate ground water and/or drinking water.

Approximately 160 to 190 coal- and petroleum-fired steam electric power plants reported collecting combustion residual leachate from either an existing (*i.e.*, active or inactive) impoundment and/or landfill. Table 4-14 presents a distribution of each management unit (impoundment or landfill) collecting leachate and the year of installation based on information from Part A from the Steam Electric Survey. As shown in Table 4-13, the majority (52 percent) of landfills collect leachate, while only 13 percent of impoundments collect leachate. However, the table also demonstrates that recently installed landfills and impoundments are more likely to be lined and to collect leachate.

Table 4-13. Age of Impoundment or Landfill Collecting Combustion Residual Leachate

Management Unit Installation Year	Landfills			Impoundments		
	Total	Number Lined	Number Collecting Leachate	Total	Number Lined	Number Collecting Leachate
2000 to Present	66	55	51	88	77	30
1990 to 2000	53	33	24	96	74	18
1980 to 1990	102	60	49	308	231	34
Before 1980	59	31	22	593	180	66
Insufficient Data	3	--	--	15	--	--
Total	**283**	**179**	**146**	**1,100**	**562**	**148**

Source: Steam Electric Survey [ERG, 2015a].

Note: The number of impoundments and landfills in the steam electric power generating industry are based on values reported in the Steam Electric Survey, which were scaled to represent the industry as a whole using the industry-weighting factors discussed in Section 3.2.

Once collected, the landfill or impoundment leachate can be recycled back into the management unit, recycled elsewhere within the plant, or discharged. Table 4-14 presents the destination of leachate collected from combustion residual impoundments and landfills. This table includes impoundments and landfills reported as producing leachate in Part F of the Steam Electric Survey, scaled to represent all industry operations. Therefore, the total number of impoundments and landfills with collected leachate differs from that presented in Table 4-13, collected from Part A of the Steam Electric Survey. The Steam Electric Survey data from Part F indicates that 47 percent of combustion residual impoundment leachate and 28 percent of combustion residual landfill leachate is returned to the management unit.[27] Plants generally discharge landfill leachate directly after collection, or treat the leachate on site and then discharge it after treatment.

[27] Part F of EPA's Steam Electric Survey requested information on the management practices of both impoundments and landfills containing fuel combustion residuals. This section included questions related to the collection and treatment of leachate from both types of management units. As described in Section 3.2, Part F of the questionnaire was sent only to a probability sampled stratum of coal- and petroleum coke-fired plants.

Table 4-14. Destination of Combustion Residual Leachate in Steam Electric Power Generating Industry

Destination	Number of Impoundments	Number of Landfills
Returned to Management Unit (Impoundment or Landfill) or Recycled Within the Plant	48 (47%)	35 (28%)
On-Site Treatment System	6 (6%)	23 (18%)
Discharged	35 (34%)	86 (68%)
Other [a]	21 (20%)	23 (18%)
Insufficient Data	7	--
Total [b]	**110**	**126**

Source: Steam Electric Survey [ERG, 2015a].

Note: The number of impoundments and landfills in this table are based on values reported in Part F of the Steam Electric Survey, which were scaled to represent the industry as a whole using the industry-weighting factors discussed in Section 3.2. The number of impoundments and landfills will not equal the numbers provided in Table 4-13 because not all plants were provided Part F of the Steam Electric Survey.

a – "Other" includes perimeter drain with no flow, underground mine pool, and underground injection.

b – Total number of impoundments and landfills is not additive because leachate may have more than one destination. For example, it is possible for leachate from one impoundment to be both treated and discharged.

4.3.6 Gasification Wastewater

IGCC plants generate wastewater from the gasification process, in which a fuel source (*e.g.*, coal or petroleum coke) is subjected to high temperature and pressure to produce a synthetic gas that is used as the fuel for a combined cycle generating unit. As described in Section 4.2.3, the specific processes used to generate and then clean the synthetic gas prior to combustion vary to some degree at the currently operating IGCC plants; however, each of these processes requires purging wastewater from the process to remove chlorides and other contaminants from the system.

As shown in Figure 4-4, there are several wastestreams generated as part of the gasification process. Additionally, there may be other wastewaters generated at IGCC plants that are not included in Figure 4-4 because they are not generated from the gasification process or other processes directly linked to the gasification process (*e.g.*, wastewater associated with sulfur recovery processes). The following is a list of the key wastewaters that are generally considered associated with the gasification process:

- Slag handling wastewater.
- Fly ash and water stream.
- Sour/grey water (which consists of condensate generated for gas cooling, as well as other wastestreams).
- CO_2/steam stripper wastewater.
- Sulfur recovery unit blowdown.

Other types of wastewater that may be present at an IGCC plant, but which are not considered gasification wastewater include:

- Blowdown from the heat recovery steam generator blowdown.
- Coal/petroleum coke pile runoff.
- Metal cleaning wastes.
- Air separation unit blowdown.
- Service water filtration backwash.
- Demineralizer system reject.
- Cooling water.

Depending on the design of the plant, wastewaters not associated with the gasification process are typically handled similarly to how they are managed at conventional pulverized coal-fired power plants. For example, coal/petroleum coke pile runoff is typically transferred to a surface impoundment and then discharged. However, these streams may also be recycled back to the slurry preparation system and sent back to the gasifier. Both IGCC plants identified as operating in 2009 treat gasification wastewaters in a vapor-compression brine concentrator. . See Section 6.5 for more information on the characteristics of gasification wastewater.

4.4 Steam Electric Wastestreams Selected for New Controls in the Final ELGs

This section describes the wastestreams generated by steam electric power plants for which EPA did not establish new discharge requirements for the ELGs.

4.4.1 Metal Cleaning Waste

The Steam Electric Power Generating ELGs define metal cleaning waste as "any wastewater resulting from cleaning [with or without chemical cleaning compounds] any metal process equipment, including, but not limited to, boiler tube cleaning, boiler fireside cleaning, and air preheater cleaning" (see 40 CFR 423.11). Plants use chemicals to remove scale and corrosion that accumulate on the boiler tubes and retard heat transfer. The major constituents of boiler cleaning wastes are the metals of which the boiler is constructed, typically iron, copper, nickel, and zinc. Boiler firesides are commonly washed with a high-pressure water spray against the boiler tubes while they are still hot. Fossil fuels with significant sulfur content will produce sulfur oxides that adsorb on air preheaters. Water with alkaline reagents is often used in air preheater cleaning to neutralize the acidity due to the sulfur oxides, maintain an alkaline pH, and prevent corrosion. The types of alkaline reagents used include soda ash, caustic soda, phosphates, and detergent.

The frequency of metal cleaning activities can vary depending on the type of cleaning operation and individual plant practices. Some operations occur as often as several times a day, while others occur once every several years. Soot blowing, the process of blowing away the soot deposits on furnace tubes, generally occurs once a day, but some units do this as often as several hundred times a day. While 83 percent of units responding to the Steam Electric Survey use steam or service air to blow soot, some plants may generate wastewater streams. Air heater cleaning is another frequent cleaning activity. About 66 percent of the units perform this operation at least once every 2 years, while other units perform this cleaning task very infrequently, only once every 40 years. Generally, plants use intake or potable water to clean the air heater [ERG, 2015a].

The following is a list of all the metal cleaning wastes that were reported in response to the Steam Electric Survey:

- Air compressor cleaning.
- Air-cooled condenser cleaning.
- Air heater cleaning.
- Boiler fireside cleaning.
- Boiler tube cleaning.
- Combustion turbine cleaning (combustion portion and/or compressor portion).
- Condenser cleaning.
- Draft fan cleaning.
- Economizer wash.
- FGD equipment cleaning.
- Heat recovery steam generator cleaning.
- Mechanical dust collector cleaning.
- Nuclear steam generator cleaning.
- Precipitator wash.
- SCR catalyst soot blowing.
- Sludge lancing.
- Soot blowing.
- Steam turbine cleaning.
- Superheater cleaning.

EPA proposed to establish new requirements for non-chemical metal cleaning waste equal to previously established BPT limitations for metal cleaning waste. The proposal was based on EPA's understanding, from industry survey responses, that most steam electric power plants manage their chemical and non-chemical metal cleaning waste in the same manner. Since then, the Agency has learned that plants refer to the same operation using different terminology; some classify non-chemical metal cleaning wastes as such while others classify it as low volume wastes. Because the survey responses reflect each plant's individual nomenclature (*i.e.*, non-chemical metal cleaning wastes versus low volume wastes), the survey results for non-chemical metal cleaning wastes are skewed.

Therefore, the final rule continues to "reserve" new requirements for non-chemical metal cleaning wastes, as the previously promulgated regulations did. By reserving limitations and standards for non-chemical metal cleaning waste in the final rule, the permitting authority must establish such requirements based on best professional judgment for any steam electric power plant discharging non-chemical metal cleaning wastes. As part of this determination, EPA expects that the permitting authority would examine the historical permitting record for the particular plant to determine how discharges of non-chemical metal cleaning wastes had been permitted in the past, including whether such discharges had been treated as low volume waste sources or metal cleaning wastes.

4.4.2 Carbon Capture Wastewater

Steam electric power plants have considered alternatives available for reducing carbon emissions. There are three main approaches for capturing the carbon dioxide (CO_2) associated with generating electricity: post-combustion, precombustion, and oxyfuel combustion.

- In post-combustion capture, the CO_2 is removed after the fossil fuel is combusted.
- In precombustion capture, the fossil fuel is partially oxidized, such as in a gasifier. The resulting syngas (CO and H_2) is shifted into CO_2 and more H_2 and the resulting CO_2 can be captured from a relatively pure exhaust stream before combustion takes place.
- In oxyfuel combustion, also known as oxycombustion, the fuel is burned in oxygen instead of air. The flue gas consists of mainly CO_2 and water vapor; the latter is condensed through cooling. The result is an almost pure CO_2 stream that can be transported to the storage, or sequestration, site and stored.

After capture, the plant would transport CO_2 to a suitable sequestration site. Approaches under consideration include the following:

- Geologic sequestration (injection of the CO_2 into an underground geologic formation).
- Ocean sequestration (typically injecting the CO_2 into the water column at depths to allow dissolution or at deeper depths where the CO_2 is denser than water and wouldform CO_2 "lakes").
- Mineral storage (where CO_2 is exothermically reacted with metal oxides to produce stable carbonates).

Based on preliminary information regarding these technologies, EPA believes these systems may result in new wastestreams at steam electric power plants that will need to be addressed. However, as these technologies are currently in the early stages of research and development and/or pilot testing, the industry has little information on the potential wastewaters generated from carbon capture processes.

As part of its sampling program, EPA obtained analytical data from two wastestreams generated from a post-combustion carbon capture pilot-scale system. The pilot-scale system was based on Alstom's chilled ammonia process. This carbon capture process generated a few wastewater bleed streams, two of which were analyzed as part of EPA's sampling program. The first stream, a pilot validation facility (PVF) bleed stream, is a purge stream that removes ammonium sulfate from the process. During sampling activities, the PVF bleed stream flow rate ranged from 800 to 5,100 gallons per day (gpd). The second stream, flue gas condensate, is a condensate stream generated from cooling the flue gas, which condenses the water vapor present. The flow rate of the flue gas condensate stream ranged from 2,600 to 9,900 gpd during sampling. Table 4-15 presents the concentrations of the pollutants measured during the EPA sampling program. The concentrations presented are the 4-day average concentrations.

According to plant personnel, for a full-scale system, a plant would transfer the PVF bleed stream to a crystallizer, producing a solid particulate product that could be used as a fertilizer [Lohner, 2010]. The condensate from the evaporation process could be reused in other plant processes or discharged to surface water.

Table 4-15. Carbon Capture Wastewater 4-Day Average Concentration Data

Analyte	Unit	4-Day Average Concentration	
		PVF Bleed Stream	Flue Gas Condensate
Classicals			
Ammonia	mg/L	26,800	< 383
Nitrate Nitrite as N	mg/L	8.98	1.80
Nitrogen, Total Kjeldahl	mg/L	42,800	740
Biochemical Oxygen Demand	mg/L	ND (14.7)	< 3.65
Chemical Oxygen Demand	mg/L	88.8	NQ (20.0)
Chloride	mg/L	NQ (300)	NQ (6.75)
Sulfate	mg/L	163,000	1,050
Cyanide, Total	mg/L	1.20	ND (0.100)
Total Dissolved Solids	mg/L	163,000	1,050
Total Suspended Solids	mg/L	27.3	< 6.75
Phosphorus, Total	mg/L	0.155	NQ (0.0500)
Total Metals			
Aluminum	ug/L	450	NQ (200)
Antimony	ug/L	2.65	ND (2.00)
Arsenic	ug/L	40.0	NQ (4.00)
Barium	ug/L	57.5	NQ (20.0)
Beryllium	ug/L	ND (2.00)	ND (2.00)
Boron	ug/L	13,000	1,540
Cadmium	ug/L	NQ (4.00)	ND (4.00)
Calcium	ug/L	24,000	< 2,390
Chromium	ug/L	1,540	< 17.5
Cobalt	ug/L	73.3	NQ (20.0)
Copper	ug/L	400	14.9
Iron	ug/L	4,380	2,020
Lead	ug/L	7.78	NQ (2.00)
Magnesium	ug/L	15,800	1,990
Manganese	ug/L	965	101
Mercury	ng/L	3,530	1,060
Molybdenum	ug/L	2,630	NQ (40.0)
Nickel	ug/L	4,530	27.5
Selenium	ug/L	4,900	128
Silver	ug/L	ND (2.00)	ND (2.00)
Sodium	ug/L	16,000	NQ (10,000)

Table 4-15. Carbon Capture Wastewater 4-Day Average Concentration Data

Analyte	Unit	4-Day Average Concentration	
		PVF Bleed Stream	Flue Gas Condensate
Thallium	ug/L	2.30	ND (2.00)
Tin	ug/L	ND (200)	ND (200)
Titanium	ug/L	NQ (20.0)	NQ (20.0)
Vanadium	ug/L	19.0	NQ (10.0)
Zinc	ug/L	293	NQ (40.0)

Source: CWA 308 Monitoring [ERG, 2012].

< – Average result includes at least one value measured below the quantitation limit. Calculation uses ½ the sample-specific quantitation limit for values below the quantitation limit.

ND – Not detected (number in parenthesis is the quantitation limit).

NQ – Analyte was measured below the quantitation limit for all four results (number shown in parenthesis is the average quantitation limit), but at least one result was measured above the method detection limit.

Note: Concentrations are rounded to three significant figures.

According to the Steam Electric Survey responses, there are no full-scale carbon capture systems operating in the industry. There are, however, two pilot-scale systems that have been tested, the one for which EPA collected the analytical data presented in Table 4-15 (currently shut down and inactive) and another one that has been decommissioned.

4.5 CHANGES IN STEAM ELECTRIC INDUSTRY POPULATION

Although EPA used Steam Electric Survey data to generate the demographics of the steam electric power generating industry presented in this section, the Agency recognizes that plant operations may have changed since plants submitted responses in 2009. These changes might be due to updated or new wastewater treatment practices, ash handling practices, changes in the type of fuel used, or plant or generating unit retirements. EPA also identified changes in plant operations from other rulemakings affecting the steam electric power generating industry. In order to explain how these changes have an impact on the numbers presented in the remaining sections of this document, such as the compliance costs and pollutant loading estimates presented in Section 9 and Section 10, EPA grouped them into the following categories:

- Plants or generating units expected to upgrade wastewater treatment technologies, convert to dry or closed-loop fly and/or bottom ash handling, convert to different fuel sources, or retire, verified by EPA from company sources (Updated Industry Profile Population).
- Plants expected to convert to dry handling or upgrade wastewater treatment technologies as a result of the coal combustion residual (CCR) rule (CCR Population).
- Plants or generating units expected to retire as a result of the Clean Power Plan (CPP) (CPP Population).

EPA incorporated the updates to the industry profile into the data presented in the remainder of this document. EPA also incorporated the updates to the industry profile into the estimates of compliance costs, pollutant loadings, and other analyses as appropriate. [28] Further, EPA also incorporated impacts from the CCR and CPP rulemakings into the estimates of compliance costs, pollutant loadings, and other analyses as appropriate.

4.5.1 Updated Industry Profile Population

The BAT limitations for the ELGs do not begin to apply until a date determined by the permitting authority that is as soon as possible beginning November 1, 2018 (approximately 3 years following promulgation of the final rule), and they must be achieved by December 31, 2023 (approximately 8 years from the promulgation of this rule). Therefore, EPA's analysis of the regulatory options considered for the ELGs included all plants subject to the previously established ELGs, accounting for plant/unit retirements and fuel conversions expected to occur prior to implementation of the final rule. EPA's analyses reflect that all generating units with company-announced retirements or fuel conversions prior to implementation of the final rule would not incur compliance costs, nor would they discharge FGD wastewater or ash transport water.[29] EPA has a high degree of confidence that the identified retirements and fuel conversions will occur because were factored into the analyses only if they could be verified by information directly from the plant operating company or a government entity. Because these retirements and fuel conversions are scheduled to occur prior to implementation of the ELGs, EPA determined there are no incremental costs or pollutant removals associated with these generating units.

In addition, EPA incorporated changes into its analyses for plants that announced they were planning to convert to a dry or closed-loop ash handling system (ash handling conversion). EPA determined that for such ash handling conversions scheduled to occur prior to implementation of the final rule, the plant would not incur compliance costs for ash transport water from the respective generating unit nor would it discharge ash transport water from the converted ash handling system.[30] The specifics of how EPA incorporated these plant operation changes into the analyses are explained in the "Changes to Industry Profile for Steam Electric Generating Units for the Steam Electric Effluent Guidelines Final Rule" (Industry Profile Changes Memo) [ERG, 2015b]. In August 2015, EPA conducted a review of all plants in the Updated Industry Profile Population to confirm that all announced retirements and fuel conversions have occurred or are still planned to occur. EPA confirmed more than 95 percent of

[28] EPA determined that steam electric generating units would incur zero or reduced compliance costs or pollutant removals associated with the ELGs if the steam electric generating unit retired, converted fuels, updated ash handling practices, or updated wastewater treatment practices prior to the implementation of the ELGs. However, EPA only included industry profile changes that were substantiated by information directly from the operating company or government entity, either through an article, report, or press release. While EPA considered industry profile changes provided in public comments, only those industry profile changes that could be verified were included in EPA's analyses.

[29] EPA accounted for all retirements and fuel conversions announced and verified as of August 2014 in the analyses. Any retirements or fuel conversions identified after that date were too late to be fully factored into all analyses; however, EPA did consider any retirements or fuel conversions identified between August 2014 and June 2015 in a sensitivity analysis. See EPA's "Changes to Industry Profile for Steam Electric Generating Units for the Steam Electric Effluent Guidelines Final Rule" ("Industry Profile Changes Memo") for more information [ERG, 2015b].

[30] EPA accounted for all ash handling conversions announced and verified as of August 2014 in the analyses. Any ash handling conversions identified after that date were too late to be fully factored into all analyses; however, EPA did consider ash handling conversions identified between August 2014 and June 2015 in a sensitivity analysis. See EPA's Industry Profile Changes Memo for more information [ERG, 2015b].

the retirements/fuel conversions and identified additional industry profile changes. The details of this analysis are provided in the "Evaluation of Verified Retirements in the Updated Industry Profile Population for the Steam Electric Effluent Guidelines Final Rule" [ERG, 2015c].

Generally, these updates to the industry profile result in a full or partial removal of the plant from the estimated compliance costs and/or pollutant loadings. For example, if the coal-fired steam electric generating units retiring, converting fuel, and/or converting ash handling practices at Plant A affected all units at Plant A that would otherwise be included in the compliance costs and/or pollutant loadings analyses, Plant A was completely removed from the analyses (*i.e.*, full removal). Conversely, a partial removal indicates that Plant B maintains at least one coal-fired steam electric generating unit expected to incur compliance costs and/or affect pollutant loadings under the ELGs. Table 4-16 displays the number of plants EPA identified as full or partial removals due to retirements/fuel conversions, bottom ash handling conversions, and/or fly ash handling conversions scheduled to occur no later than December 31, 2023.

Table 4-16. Number of Plants Removed from ELG Compliance Costs and Pollutant Loadings Estimates Due to Updates to the Industry Profile

Type of Removal from Costs and/or Loadings	Retirement or Fuel Conversion	Bottom Ash Conversion	Fly Ash Conversion
Full	145	17	18
Partial	25	0	0
Total	**170**	**17**	**18**

Source: Industry Profile Changes Memo [ERG, 2015b].

Note: The numbers in this table reflect retirements and conversions identified prior to August 2014.

Note: Plants can be considered both a retirement and an ash conversion if some units are retiring and other units are converting. However, if EPA identified a plant with the same units retiring and converting, the plant is considered only a retirement.

EPA incorporated changes into its compliance costs, pollutant loadings, and other analyses for plants that announced wastewater treatment upgrades. Specifically, three plants that upgraded their FGD wastewater treatment system since 2009 were given credit for FGD wastewater "treatment in place" when calculating plant compliance cost estimates, see Section 9.4.1. Similarly, two plants that upgraded or are planning to update their coal combustion residual leachate treatment system after 2009 were given credit for "treatment in place," see Section 9.8.[31]

4.5.2 CCR Population

EPA coordinated the requirements of the CCR rule and the ELGs to avoid establishing overlapping regulatory requirements and to facilitate the implementation of engineering, financial, and permitting activities. For the ELGs, EPA calculated compliance costs, pollutant

[31] EPA accounted for all wastewater treatment upgrades announced and verified as of August 2014 in the analyses. Any wastewater treatment upgrades identified after that date were too late to be fully factored into all analyses; however, EPA did consider any wastewater treatment upgrades identified between August 2014 and June 2015 in a sensitivity analysis. See EPA's Industry Profile Changes Memo for more information [ERG, 2015b].

loadings/removals, and other analyses taking the effect of the CCR rule into account.[32] For more information about how EPA incorporated the CCR rule into the ELG analyses, see Section 9. Table 4-17 presents the number of plants that are removed from compliance cost estimates and pollutant loadings for bottom ash transport water and/or fly ash transport water because they are determined to be converting to dry handling as a result of the CCR rule. Additionally, EPA identified adjustments to FGD compliance cost estimates and pollutant loadings due to wastewater treatment upgrades projected to result from plants implementing the CCR rule, as well as adjustments to ash compliance cost estimates and pollutant loadings to reflect changes in CCR storage handling practices that would result from implementing the CCR rule; however, these adjustments do not change the number of plants incurring costs for the ELGs.

Table 4-17. Number of Plants Removed from ELG Compliance Costs and Pollutant Loadings Estimates Due to Implementation of the CCR Rule

Total for Regulatory Option D	Bottom Ash	Fly Ash
27	**23**	**12**

Note: Only includes plants that are removed from compliance costs or pollutant loadings to reflect changes resulting from the CCR rule prior to implementing the ELGs. Therefore, if a plant was already removed to reflect the Updated Industry Profile Population, the plant is not included in this table.

4.5.3 CPP Population

The CPP establishes limits on emissions to reduce carbon pollution from steam electric power plants. EPA projects that as plants take steps to implement the CPP, some plants may retire one or more generating units prior to the unit(s) having to implement the ELGs. To account for this, EPA incorporated projected CPP retirements into EPA's compliance cost estimates, pollutant loadings, and other analyses for the ELGs. For more information about how EPA incorporated the CPP into the ELG analyses, see Section 9. Similar to the Updated Industry Profile Population described in Section 4.5.1, EPA classified CPP retirements as partial or full removals. Table 4-18 presents the number of plants that are either partially or fully removed from the cost and pollutant removal estimates due to retirements projected to result from implementing the CPP.

Table 4-18. Number of Plants Removed from ELG Compliance Costs Due to Implementation of the CPP

Type of Removal	Total for Regulatory Option D	Bottom Ash	Fly Ash	FGD	IGCC
Full	47	38	3	18	1
Partial	19	15	5	9	0
Total	**66**	**53**	**8**	**27**	**1**

Note: Only includes plants that are removed from compliance costs to reflect implementation of the CPP. Therefore, if a plant was already removed to reflect the Updated Industry Profile Population or implementation of the CCR rule (*i.e.*, CCR Population), the plant is not included in this table.

[32] EPA also conducted additional analyses to estimate what the costs and pollutant removals for the ELGs would be in the absence of the CCR rule.

4.6 REFERENCES

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SECTION 5
INDUSTRY SUBCATEGORIZATION

This section presents information about factors EPA considered in evaluating whether different effluent limitations or standards are warranted for certain facilities in the Steam Electric Power Generating Point Source Category (Steam Electric Category). Section 5.1 describes why EPA considers factors that could lead to establishing different requirements for certain facilities in the category and presents background on the industry categorization established in the 1974 and 1982 effluent limitations guidelines and standards (ELGs) rulemakings. Section 5.2 presents the factors considered in detail and the analyses EPA performed to review whether subcategorization was appropriate for establishing the ELGs for this category.

5.1 SUBCATEGORIZATION FACTORS

The Clean Water Act (CWA) requires EPA to consider a number of different factors when developing ELGs for a particular industry category (Section 304(b)(2)(B), 33 U.S.C. § 1314(b)(2)(B)). For best available control technology economically available (BAT), in addition to the technological availability and economic achievability, these factors are the age of the equipment and plants, the process employed, the engineering aspects of the application of various types of control techniques, process changes, the cost of achieving such effluent reduction, non-water quality environmental impacts (including energy requirements), and such other factors the Administrator deems appropriate. One way EPA may take these factors into account, where appropriate, is by dividing a point source category into groupings called "subcategories." Regulating a category by subcategory, where determined to be warranted, ensures that each subcategory has a uniform set of ELGs that take into account technology availability and economic achievability and other relevant factors unique to that subcategory.

The current Steam Electric Power Generating ELGs do not divide plants or process operations into subcategories, although they do include different requirements for cooling water discharges from plants smaller than 25 MW generating capacity [U.S. EPA, 1974; U.S. EPA, 1982]. For this final rule, EPA evaluated whether different effluent requirements should be established for certain plants within the Steam Electric Category using information from responses to the industry surveys, site visits, sampling, and other data collection activities (see Section 3 for more details). EPA performed analyses to assess the influence of age, geographic location, size, fuel type, and processes employed on the wastewaters generated, discharge flow rates, pollutant concentrations, and treatment technology availability at steam electric power plants to determine whether subcategorization was appropriate.

5.2 ANALYSIS OF SUBCATEGORIZATION FACTORS

EPA assessed the influence of age, geographic location, size, fuel type, and processes employed (*e.g.*, scrubber and boiler type) on the wastewaters generated at steam electric power plants and the availability of technologies to manage those wastewaters. The following sections summarize the analyses performed as part of the subcategorization evaluation. For additional information on the specific analyses performed as part of the evaluation, see the memorandum entitled "Steam Electric Effluent Guidelines – Evaluation of Potential Subcategorization Approaches" [ERG, 2015a].

5.2.1 Age of Plant or Generating Unit

EPA analyzed the age of the plants and the generating units included in the scope of the rule and determined that the age of the plant by itself does not affect the wastewater characteristics, the processes in place, or the ability to install the treatment technologies evaluated as part of the final rule. For example, although the "zero discharge" NSPS for fly ash transport water was not promulgated until 1982 and prior to that date most generating units were built with wet fly ash handling systems, EPA determined that many generating units have since converted their wet handling systems to dry fly ash handling. As a result, most generating units now use dry handling or are in the process of converting to dry fly ash handling. The age of the generating unit does not hinder the ability to retrofit dry fly ash systems, and the data in the record show that the majority of the steam electric generating units that retrofitted to dry fly ash handling are at least 30 years old [ERG, 2015a].

Based on data presented in the Steam Electric Survey, more than 80 percent of generating units built in the last 20 years installed dry bottom ash handling at the time of construction. In addition, many generating units originally built with wet-sluicing systems have converted or are in the process of converting to dry or closed-loop bottom ash handling. The age of the generating unit does not hinder the ability to retrofit to a dry or closed-loop system, and the data in the record show that the majority of the steam electric generating units that retrofitted to dry bottom ash handling are at least 30 years old [ERG, 2015a].

EPA determined that the age of plants and steam electric generating units also does not impact the plants' ability to install the FGD wastewater treatment technologies that are the basis for the BAT/PSES effluent limits because the treatment system for the FGD wastewater is distinctly separate from the generating unit. EPA reviewed the age of plants, with available age data, that operate chemical precipitation followed by biological treatment to treat FGD wastewater and determined that each of the plants are at least 20 years old, and one of the plants is more than 50 years old. Additionally, based on available age data, EPA determined that plants operating evaporation systems are at least 25 years old, and one of the plants is at least 45 years old [ERG, 2015a].

EPA also evaluated whether plants might choose to retire older generating units rather than install retrofits to comply with the revised ELGs, but did not find that to be the likely outcome. EPA analyzed the impacts that the ELGs may have on the steam electric industry using the Integrated Planning Model (IPM) and estimated that the requirements associated with the ELG would have the net effect of two generating unit (partial) closures and one steam electric generating plant (full) closure, for a net change of 843 MW. EPA determined that the majority (over 80 percent) of coal- and oil-fired steam electric generating units are over 30 years old. EPA determined that the generating units predicted to retire are also over 30 years old. These generating units represent a small percentage of the operating generating units that are over 30 years old and, given that many other generating units more than 30 years old are projected to continue operating, the age of the plant or generating unit is not a significant factor. Therefore, EPA did not establish subcategories based solely on the age of the plant or generating unit for this final rule.

5.2.2 Geographic Location

EPA analyzed the geographic location of steam electric power plants included in the scope of the rule. EPA determined that the geographic location of the plant by itself does not affect the wastewater characteristics, the processes in place, or the ability to install the treatment technologies evaluated as part of the final rule. Wet flue gas desulfurization (FGD) systems, both wet and dry fly ash handling systems, and both wet and dry bottom ash handling systems are located throughout the United States, as illustrated in Section 4. Additionally, the location of the plant does not affect the plant's ability to install the treatment technologies evaluated as part of the final rule.

For example, a plant in the southern United States would be able to install and operate the chemical precipitation and biological treatment system that is the BAT technology basis for controlling discharges of FGD wastewater. Because of the warm climate, plants in southern states may find it appropriate to install heat exchangers to keep the FGD wastewater temperature at ideal operating conditions during the summer months. EPA's approach for estimating compliance costs takes such factors into account. Additionally, a plant in the northern United States will be able to install and operate the chemical precipitation and biological treatment system, the BAT technology basis for controlling discharges of FGD wastewater, and the remote mechanical drag system (MDS) closed-loop bottom ash handling system, the BAT technology basis for controlling discharges of bottom ash transport water. EPA's compliance cost estimates account for costs to address climate concerns in the northern United States (*e.g.*, costs to keep the FGD wastewater temperature at ideal operating conditions and costs to protect the remote MDS from adverse weather conditions).

Based on the information in the public record regarding the current geographic location of the various types of systems generating the wastewaters addressed by this rulemaking and engineering knowledge of the operational processes and candidate BAT/NSPS (new source performance standards) treatment technologies, EPA determined that subcategories based on plant geographic location are not warranted.

5.2.3 Size

EPA analyzed the size (*i.e.*, nameplate generating capacity in megawatts (MW)) of the steam electric generating units and determined that it is an important factor influencing the volume of the discharge flow from the plant. Typically, as the size of the generating unit increases, so do the discharge flows of ash transport water. In general, this is to be expected because the larger the generating unit, the more fuel it consumes, which generates more ash, and the more water it uses in the water/steam thermodynamic cycle [ERG, 2015b]. Although the volume of the wastewater increases with the size of the generating unit, the pollutant characteristics of the wastewater generally are unaffected by the size of the generating unit, and any variability observed in wastewater pollutant characteristics does not appear to be correlated to generating capacity.

As a result of its evaluation, EPA believes that, in certain circumstances, it would be appropriate to apply different limitations for a class of existing generating units based on size.

Section 8 discusses in detail EPA's establishment of different limitations and standards for certain existing generating units based on their size.

5.2.4 Fuel Type

The type of fuel (*e.g.*, coal, petroleum coke, oil, gas, nuclear) used to create steam most directly influences the type and number of wastestreams generated. For example, gas and nuclear power plants typically generate cooling water, metal cleaning wastes (both chemical and non-chemical), and other low volume wastestreams, but do not generate wastewaters associated with air pollution control devices (*e.g.*, fly ash and bottom ash transport water, FGD wastewater). Coal, oil, and petroleum coke power plants may generate all of those wastewaters. The wastestream that is most influenced by fuel selection is the ash transport water because the quantity and quality of ash generated from oil-fired units is different from that generated from coal- and petroleum coke-fired units. Additionally, the quantity and quality of ash differs based on the type of oil used in the boiler. For example, heavy or residual oils such as No. 6 fuel oil generate fly ash and may generate bottom ash, but lighter oils such as No. 2 fuel oil may not generate any ash.

From an analysis of responses to the *Questionnaire for the Steam Electric Power Generating Effluent Guidelines* (Steam Electric Survey), EPA determined that 74 percent of the steam electric generating units in the industry burn more than one type of fuel (*e.g.*, coal and oil, coal and gas). Some of these generating units may burn only one fuel at a time, but burn both types of fuels during the year. Other generating units may burn multiple fuels at the same time. In cases where a generating unit burns multiple fuels at the same time, it would be impossible to separate the wastestreams by fuel type [ERG, 2015b].

EPA did not identify any basis for subcategorizing gas-fired and nuclear generating units. These generating units generally manage their process wastestreams in the same manner as other steam electric generating units. However, based on responses to the Steam Electric Survey, there are some oil-fired generating units that generate and discharge fly ash and/or bottom ash transport water. For these reasons, EPA looked carefully at oil-fired generating units. As a result, EPA determined that, in certain circumstances, it is appropriate to apply different limits to existing oil-fired generating units. Section 8 discusses in detail EPA's establishment of different limitations and standards for existing oil-fired generating units.

5.2.5 Processes Employed

EPA analyzed different processes employed at plants, including the FGD scrubber and boiler type, included in the scope of this rule. Specifically, EPA used data from the Steam Electric Survey and the detailed study to compare characteristics of once-through FGD systems to recirculating systems and to determine if the type of system affects the plant's ability to install and operate the FGD treatment technologies evaluated as part of the final rule. Based on the comparison, EPA found that there is no distinguishable difference between the two types of systems related to materials of construction, operating chloride levels, and flow rates (*i.e.*, slurry blowdown flow rates for the once-through FGD systems are within the range of the FGD purge flow rates for recirculating systems). Additionally, EPA compared analytical data for untreated FGD wastewater from once-through and recirculating systems. Based on the comparison of total metals concentrations, EPA found that all pollutants in untreated FGD wastewater from once-through FGD systems were within the range of pollutant concentrations for FGD wastewater from recirculating systems. Therefore, EPA determined that subcategories based on scrubber type are not warranted [ERG, 2015a].

EPA also analyzed data in the Steam Electric Survey to determine if the steam electric generating unit boiler type, specifically cyclone and circulating fluidized bed (CFB) boilers, affects plants' ability to install and operate the bottom ash handling treatment technologies evaluated as part of the final rule. Based on Steam Electric Survey data, EPA determined that there are plants with cyclone and CFB boilers that collect and manage bottom ash with an MDS. Additionally, based on vendor contacts, EPA determined that remote MDS conversions are suitable for these boiler types because the traditional wet-sluicing system is still operated to collect and transport bottom ash to the remote MDS. Therefore, EPA determined that subcategories based on boiler type are not warranted.

5.3 References

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SECTION 6 WASTEWATER CHARACTERIZATION AND POLLUTANTS OF CONCERN

This section summarizes information gathered from survey data, EPA sampling data, Clean Water Act (CWA) Section 308 sampling data, and industry- and state-submitted plant monitoring data on wastewater generation practices associated with the steam electric power generating industry. EPA used plant responses from the *Questionnaire for the Steam Electric Power Generating Effluent Guidelines* (Steam Electric Survey) to identify the population of plants that generate and discharge in 2009 the wastestreams for which EPA is finalizing new or revised effluent limitations and standards. These wastestreams include flue gas desulfurization (FGD) wastewater, fly and bottom ash transport water, combustion residual leachate, flue gas mercury control (FGMC) wastewater, and gasification wastewater. Similar to Section 4, EPA used the weighted Steam Electric Survey results to represent the steam electric power generating industry in 2009 because they provide more complete information about power plant operations. Additionally, EPA characterized these wastestreams based on sampling, plant-monitoring, and other industry data. Sections 6.1 through 6.6 provide details on wastewater generation rates and provide characterization data for the untreated process wastewater, where available. Section 6.6 identifies the pollutants of concern (POCs) related to this rulemaking.

6.1 FGD WASTEWATER

EPA used the responses from Part B of the Steam Electric Survey to develop the list of plants operating FGD systems. Plants reported information on FGD systems in operation as of 2009 and planned FGD systems through 2020. EPA included plants with FGD systems in operation as of 2009 and planned systems reported in the Steam Electric Survey[33] to accurately reflect the potential compliance costs and pollutant removals associated with the final rule. This section describes the amount of FGD wastewater generated by these FGD systems and discusses the characteristics of FGD wastewater.

Wet FGD scrubber systems are classified into two categories, recirculating wet FGD systems and once-through wet FGD systems, as shown in Figure 4-7. In a recirculating system, most of the FGD slurry at the bottom of the scrubber is recirculated back within the scrubber and occasionally a blowdown stream, called FGD slurry blowdown, is transferred away from the scrubber. The slurry blowdown stream undergoes solids separation, and the wastewater is either recycled back to the scrubber or transferred to a wastewater treatment system as FGD scrubber purge. In a once-through system, all of the FGD slurry at the bottom of the scrubber leaves the scrubber without recirculating the slurry within the system. FGD wastewater can include the FGD scrubber purge from a recirculating systems, the FGD slurry from once-through systems, any gypsum wash water, and water generated from the solids separation/dewatering process.

Table 6-1 summarizes FGD slurry blowdown flow rates for plants with FGD systems that generate slurry blowdown. In 2009, a typical steam electric power plant generated on average 2.1 million gallons per day (MGD) of FGD slurry blowdown. As described previously, the FGD

[33] EPA included FGD systems reported in the Steam Electric Survey to be in operation as of January 1, 2014 (*i.e.*, those expected to be built between 2010 and 2013).

slurry blowdown undergoes solids separation/dewatering before being transferred to treatment or is recycled back to the scrubber.

Table 6-1. FGD Slurry Blowdown Flow Rates for the Steam Electric Power Generating Industry in 2009

	Number of Plants	Average Flow Rate	Median Flow Rate	Range of Flow Rate
Flow Rate per Plant				
Gallons per day (gpd)/plant	150	2,100,000	1,110,000	3,300 – 24,200,000

Source: Steam Electric Survey [ERG, 2015a].

Note: Wastewater flow rates are rounded to three significant figures.

Note: The number of plants generating FGD slurry blowdown is based on values reported in the Steam Electric Survey for operations in 2009, which were scaled to represent the industry as a whole using the industry-weighting factors discussed in Section 3.2. The reported values do not account for changes in the industry since 2009.

Note: EPA did not have sufficient information in the Steam Electric Survey to determine the generation flow rates for 13 plants. Although EPA included these plants in the count of plants generating FGD wastewater, EPA did not include them in the determination of the average, median, or range of generation flow rates in the table.

As described in Section 4.3.3, the FGD wastewater generated by wet FGD systems is removed as slurry blowdown to purge chlorides from the system. The FGD slurry blowdown is typically generated intermittently. The factors that can affect the flow rate of the FGD wastewater generated at the plant include the type of coal used, scrubber design and operating practices, solids separation process, and solids dewatering process.

The type of coal burned at the plant can affect the FGD wastewater flow rate. Generally, a plant burning a higher sulfur coal generates higher FGD wastewater flow rates. Higher sulfur coals produce more sulfur dioxide (SO_2) in the combustion process, which in turn increases the amount of SO_2 removed in the FGD scrubber. As a result, more solids are generated in the reaction in the scrubber, which increases the frequency at which FGD wastewater is removed from the system.

Likewise, using high chlorine coal can increase the volume and frequency of the FGD wastewater generated by the system. Many FGD systems are designed with materials resistant to corrosion for specific chloride concentrations. The chlorine present in the coal leads to chlorides present in the FGD system. As the FGD system recirculates the water in the system, the chlorides build up within the scrubber. As the chloride concentration begins approaching the maximum allowable limit for the specific material of construction of the FGD system, the plant purges some of the wastewater to remove the chlorides from the system. In the United States, FGD scrubbers are generally constructed of alloys that are designed to withstand a chloride concentration of 20,000 parts per million (ppm) or more. The larger the maximum allowable chloride concentration in the scrubber, the lower the FGD wastewater flow rate; however, this lower purge rate leads to additional cycling in the scrubber, which affects the pollutant concentrations in the FGD wastewater [Babcock & Wilcox, 2005]. Based on information collected from the EPA sampling program, these chloride concentrations do not impact the treatability of FGD wastewater.

Pollutant concentrations in FGD wastewater can also vary to some degree from plant to plant depending on the coal type, the sorbent used, the materials of construction in the FGD system, the FGD system operation, the level of recirculation in the scrubber, and the air pollution control systems operated upstream of the FGD system. The fuel (coal or petroleum coke) is the source of most of the pollutants that are present in FGD wastewater (*i.e.*, the pollutants in the coal are likely to be in the FGD wastewater). The sorbent used in the FGD system also introduces pollutants into the FGD wastewater and, therefore, the type and source of the sorbent used affects the pollutant concentrations in the FGD wastewater.

The sorbent and type of oxidation the FGD system used (*i.e.*, forced oxidation, inhibited oxidation, natural oxidation) affects the species of pollutants present in the FGD wastewater. According to the Electric Power Research Institute (EPRI), forced oxidation systems generate selenium species that are mostly present as selenate whereas natural and inhibited oxidation systems generate selenium species that are mostly present as selenite [EPRI, 2006]. The FGD wastewater characteristics presented later in this section represent data from plants operating limestone forced oxidation systems. EPA focused the sampling program on plants operating limestone forced oxidation systems because most plants operate these systems (as shown in Table 4-12. Natural or inhibited oxidations systems use other types of sorbents (*e.g.*, lime, mag-lime) and generally do not discharge FGD wastewater. They either operate complete-recycle systems or the water is evaporated in evaporation ponds or consumed during a pozzolanic reaction.

The FGD system operation and materials of construction in the FGD system affect the types of pollutants in the wastewater. Using organic acid additives contributes to biochemical oxygen demand (BOD_5) in the FGD wastewater. Additionally, the oxidation-reduction potential (ORP) of the FGD scrubber affects the overall wastewater characteristics. EPA evaluated the effects of ORP on the treatability of FGD wastewater, and concluded that these effects can be controlled, as described in Section 7.1.3.

The materials of construction and the other FGD system operations could also affect the concentration of pollutants in the FGD wastewater because they affect the amount of recycle within the system, which in turn, affects the rate at which the FGD wastewater is generated. For example, during the detailed study of the steam electric power generating industry, EPA collected samples from the Tennessee Valley Authority's Widows Creek Fossil Plant (Widows Creek), which operates once-through FGD systems. These FGD systems do not cycle the wastewater within the system, thereby generating FGD slurry blowdown continuously and potentially at a larger flow rate compared to plants that do recirculate the FGD water. EPA compared wastewater characteristics from FGD slurry blowdown at once-through FGD systems to FGD scrubber purge wastewater characteristics at recirculating FGD systems to determine whether the operations generate different wastewater characteristics. EPA compared data from Widow's Creek (representing once-through FGD systems) to the monitoring data submitted in Part B Section 6 of the Steam Electric Survey for FGD slurry blowdown and to data EPA collected during the EPA sampling program and CWA 308 monitoring program for FGD scrubber purge wastewater from recirculating systems. Although once-through systems operate differently from recirculating systems, EPA determined that wastewater characteristics for once-through FGD systems fall within the concentration range observed for recirculating FGD systems and pollutants are present at treatable levels [ERG, 2015b]. Because of the larger flow rate associated with the once-through systems, EPA also evaluated all plants with larger FGD wastewater flow rates (*i.e.*, greater than or equal to 1,000 gpm) to determine if the FGD system could accommodate the buildup of additional chlorides associated with recirculating the FGD wastewater back to the FGD system. For more information on this analysis, see Section 4.5.2 of EPA's *Incremental Costs and Pollutant Removals for Final Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category Report* [ERG, 2015c].

The air pollution controls operated upstream of the FGD system can also affect the FGD wastewater characteristics. For example, if a plant does not operate a particulate collection system (*e.g.*, electrostatic precipitator, or ESP) upstream of the FGD system, the system will act as the particulate control system and the FGD blowdown exiting the scrubber will contain fly ash and other particulates. As a result, the FGD wastewater may contain increased concentration of pollutants associated with the fly ash, such as arsenic and mercury. Based on responses to the Steam Electric Survey, EPA determined that there are approximately 15 to 25 coal- and petroleum coke-fired generating units that operate without a particulate collection system prior to the FGD system. EPRI collected data from a plant that has a generating unit with this configuration as well as a generating unit that operates an ESP prior to its FGD system. Comparing the data from the EPRI report for the untreated FGD wastewater from these two different units, EPA determined that the concentrations of mercury and selenium did not differ. Nitrate-nitrite as N and total suspended solids (TSS) concentrations are higher in FGD wastewater for the generating unit that operates the ESP; however, the concentration of arsenic is higher for the unit that does not operate the ESP [EPRI, 1998a; EPRI, 1998b]. Therefore, those plants operating FGD systems without an ESP may have higher arsenic concentrations present in their FGD wastewater. Nonetheless, based on the information from its sampling program, EPA determined that arsenic is treated to low levels in the chemical precipitation technology selected as part of the BAT technology basis for control of FGD wastewater, regardless of the influent concentrations entering the system.

Research conducted by EPA's Office of Research and Development (ORD) has shown that using post-combustion nitrogen oxide (NO_x) controls (*e.g.*, selective catalytic reduction (SCR) and selective noncatalytic reduction (SNCR)) is correlated to an increased fraction of chromium in coal combustion residuals (CCR) (including FGD wastes) being oxidized to hexavalent chromium (Cr^{+6}). Hexavalent chromium is a more soluble and more toxic form of chromium than the trivalent chromium (Cr^{+3}) usually measured in CCRs. This could explain why ORD has observed increased leachability of chromium when post-combustion NO_x controls are operating [U.S. EPA, 2008]. As part of its sampling program, EPA collected samples from four plants operating SCRs during the sampling, one plant operating SNCRs during the sampling, and two plants that were not operating the SCR/SNCR during the sampling. EPA compared the influent FGD wastewater characteristics from these plants to evaluate whether operating the NO_x control systems led to higher concentrations of certain pollutants. EPA found that none of the plants had detectable concentrations of hexavalent chromium in the influent FGD wastewater samples, except for one of the plants that was not operating its SCR/SNCR at the time. Additionally, EPA found that the concentrations of ammonia and nitrate-nitrite as N are not significantly different for the plants operating NO_x controls compared to the plants not operating

NO_x controls.[34] While the ammonia and nitrate-nitrite as N concentrations were higher for some of the plants operating NO_x controls compared to the plants not operating NO_x controls, some plants operating NO_x controls had lower concentrations of ammonia and nitrate-nitrite as N compared to plants not operating NO_x controls.

Table 6-2 summarizes the FGD wastewater discharged by the steam electric power generating industry. EPA estimates 100 coal- and petroleum coke-fired plants discharge FGD wastewater out of the 150 plants operating wet FGD systems. Collectively, these plants are expected to discharge 16.1 billion gallons of FGD wastewater per year, with an average total industry daily discharge of 0.45 MGD per plant. The amount of FGD wastewater discharged by the steam electric power generating industry is less than the amount of blowdown it generates by the industry, as shown in Table 6-1, because some plants recycle FGD blowdown from the scrubber to use as FGD preparation water and in other non-FGD plant processes (*e.g.*, ash transport water). Table 6-2 also presents the distribution of FGD wastewater discharged based on type of coal used.

Table 6-2. FGD Wastewater Discharges for the Steam Electric Power Generating Industry in 2009

	Number of Plants Discharging	Average Discharged Wastewater Flow (gpd/plant)
Total	100	451,000
Coal Type [a]		
Bituminous	64	488,000
Subbituminous	15-20	157,000
Lignite	1-5	525,000
Blend [b]	10-15	555,000

Source: Steam Electric Survey [ERG, 2015a].

Note: Wastewater flow rates are rounded to three significant figures.

Note: Certain fields contain ranges of values to protect the release of information claimed confidential business information (CBI).

Note: The number of plants discharging FGD wastewater is based on values reported in the Steam Electric Survey for operations in 2009, which were scaled to represent the industry as a whole using the industry-weighting factors discussed in Section 3.2. The reported values do not account for changes in the industry since 2009.

Note: EPA did not have sufficient information in the Steam Electric Survey to determine discharge flow rates for two plants. Although EPA included these plants in the count of plants discharging FGD wastewater, EPA did not include them in the determination of the average discharge flow rate.

a - Coal type classification is based on the types of coal burned in the units serviced by the wet FGD systems at each plant.

b - Plants operating wet FGD systems servicing units that burn two or more different coal types are classified as 'blend'.

[34] EPA evaluated the ammonia and nitrate-nitrite as N concentrations because ammonia is injected into the flue gas as part of the operation of the SCR/SNCR; therefore, EPA had hypothesized that there might be higher concentrations of these pollutants in the FGD wastewater for plants operating these systems.

As discussed in Section 3.4, EPA conducted on-site sampling activities as part of its sampling program and required a subset of plants to collect additional data under the CWA Section 308 monitoring program to characterize the FGD wastewater from steam electric power plants. To supplement its data collection activities, EPA also received plant monitoring data through public comments, plant-specific data requests, and requests to state authorities, which are described in Sections 3.5 and 3.6. EPA used sampling data and plant monitoring data to characterize the untreated FGD wastewater generated by the steam electric power generating industry. Table 6-3 presents the average pollutant concentrations of the influent to the FGD wastewater treatment systems (*i.e.*, downstream of the solids separation/solids dewatering processes). As shown in the table, FGD wastewater contains chloride, sulfate, total dissolved solids (TDS), TSS, and bioaccumulative pollutants such as arsenic, mercury, and selenium. Additionally, pollutants such as boron, calcium, magnesium, manganese, and sodium, are largely present in the dissolved phase.

Table 6-3. Average Pollutant Concentrations in Untreated FGD Wastewater

Analyte	Unit	Average Total Concentration	Average Dissolved Concentration [a]
Classicals			
Ammonia as Nitrogen	mg/L	13.1	NA
Nitrate-Nitrite as N	mg/L	91.4	NA
Nitrogen, Kjeldahl	mg/L	34.9	NA
Biochemical Oxygen Demand	mg/L	8.18	NA
Chemical Oxygen Demand	mg/L	345	NA
Chloride	mg/L	7,180	NA
Sulfate	mg/L	13,300	NA
Cyanide, Total	mg/L	0.733	NA
Total Dissolved Solids	mg/L	33,300	NA
Total Suspended Solids	mg/L	14,500	NA
Phosphorus, Total	mg/L	4.02	NA
Metals, Metalloids, and other Nonmetals			
Aluminum	ug/L	331,000	1,470
Antimony	ug/L	28.9	3.87
Arsenic	ug/L	507	7.07
Barium	ug/L	2,750	284
Beryllium	ug/L	17.5	2
Boron	ug/L	242,000	266,000
Cadmium	ug/L	127	128
Calcium	ug/L	3,290,000	2,050,000
Chromium	ug/L	1,270	4.17
Hexavalent Chromium	ug/L	NA	4.76
Cobalt	ug/L	245	206
Copper	ug/L	673	20.1
Iron	ug/L	566,000	100

Table 6-3. Average Pollutant Concentrations in Untreated FGD Wastewater

Analyte	Unit	Average Total Concentration	Average Dissolved Concentration [a]
Lead	ug/L	315	1.00
Magnesium	ug/L	3,250,000	3,370,000
Manganese	ug/L	85,700	106,000
Mercury	ug/L	289	7.19
Molybdenum	ug/L	273	136
Nickel	ug/L	1,490	973
Selenium	ug/L	3,130	1,130
Silver	ug/L	8.18	1.00
Sodium	ug/L	2,520,000	276,000
Thallium	ug/L	22.1	15.1
Tin	ug/L	164	100
Titanium	ug/L	4,300	10
Vanadium	ug/L	1,300	13.4
Zinc	ug/L	4,110	1,580

Source: Steam Electric Analytical Database for the Final Rule [ERG, 2015d].

NA - Not applicable. Samples were not analyzed for this particular analyte.

Note: Concentrations are rounded to three significant figures.

a – EPA calculated the average concentrations based on various data sets available for untreated FGD wastewater (as described in Section 3). As a result of using various data sets, the average dissolved concentrations presented in the table may be higher than the total concentrations; however, the pollutant concentrations for untreated FGD wastewater are not used in EPA's loadings calculations.

6.2 Ash Transport Water

As described in Section 4.3, plants often use water to remove fly and bottom ash from the particulate removal systems and boiler, respectively. This ash transport water can be reused as ash transport water or sent to treatment, typically in an on-site impoundment, and then discharged. This section presents an overview of the amount of fly ash and bottom ash transport water generated at coal-fired power plants within the steam electric power generating industry. This section also discusses the characteristics of fly ash and bottom ash transport water and the amount of ash transport water discharged to surface water.

6.2.1 Fly Ash Transport Water

Fly ash transport water is one of the largest wastewater sources generated at coal-fired power plants. Many of the large baseload units generate enough fly ash that they operate fly ash transport water systems continuously, while some smaller units and peaking units typically generate less fly ash, and therefore, may generate fly ash transport water intermittently.[35,36] Table 6-4 presents the fly ash transport water flow rates generated by steam electric power plants. The fly ash transport water flow rate is the amount of the fly ash transport water that is pumped with the fly ash to the impoundment over time; however, it is not necessarily the same as the amount of fly ash transport water discharged to surface water due to evaporation, infiltration, recycle, or other processes (see Section 6.2.3). The steam electric power generating industry generated 209 billion gallons of fly ash transport water in 2009, with the average plant generating 4.27 MGD.

Table 6-4. Fly Ash Transport Water Flow Rates for the Steam Electric Power Generating Industry in 2009

	Number of Plants	Average Flow Rate	Median Flow Rate	Range of Flow Rate
Flow Rate per Plant				
gpd/plant	145-150	4,270,000	2,140,000	4,000-35,700,000

Source: Steam Electric Survey [ERG, 2015a].

Note: Wastewater flow rates are rounded to three significant figures.

Note: Certain fields contain ranges of values to protect the release of information claimed confidential business information (CBI).

Note: The number of plants generating transport water is based on values reported in the Steam Electric Survey for operations in 2009, which were scaled to represent the industry as a whole using the industry-weighting factors discussed in Section 3.2. The reported values do not account for changes in the industry since 2009.

Note: EPA did not have sufficient information in the Steam Electric Survey to determine generation flow rates for nine plants. Although EPA included these plants in the count of plants generating fly ash transport water, EPA did not include them in the determination of the average, median, or range of generation flow rates in the table. Additionally, some plants reported that they generated fly ash transport water but may not have specified a wet ash handling system in another part of the Steam Electric Survey (see Table 4-7). EPA included these plants in its determination of the generation rates presented in this table.

6.2.2 Bottom Ash Transport Water

Bottom ash transport water is an intermittent stream from steam electric generating units. The bottom ash transport water flow rates are typically not as large as the fly ash transport water flow rates. However, bottom ash transport water is still one of the larger volume wastestreams for steam electric power plants. Table 6-5 presents the bottom ash transport water flow rates reported by the industry. The bottom ash transport water flow rate is the amount of the bottom ash transport water that is pumped with the bottom ash to the impoundment over time; however, it is not necessarily the same as the amount of bottom ash transport water discharged to surface water due to evaporation, infiltration, recycle, or other processes (see Section 6.2.3). Although the average daily flow rate per plant is approximately 40 percent less than the average fly ash transport water flow rate presented in Table 6-4, there are significantly more plants generating bottom ash transport water than those generating fly ash transport water. The industry generated

[35] A baseload unit is a generating unit normally operating to produce electricity at an essentially constant rate. The unit will typically run for extended periods of time.

[36] A peaking unit is a generating unit normally used only during peak-load periods of electricity demand or to replace the loss of another generating unit.

297 billion gallons of bottom ash transport water in 2009, with the average plant generating 2.49 MGD.

Table 6-5. Bottom Ash Transport Water Flow Rates for the Steam Electric Power Generating Industry in 2009

	Number of Plants	Average Flow Rate	Median Flow Rate	Range of Flow Rate
Flow Rate per Plant				
gpd/plant	348	2,490,000	1,030,000	3,150-34,600,000

Source: Steam Electric Survey [ERG, 2015a].

Note: Wastewater flow rates are rounded to three significant figures.

Note: The number of plants generating transport water is based on values reported in the Steam Electric Survey for operations in 2009, which were scaled to represent the industry as a whole using the industry-weighting factors discussed in Section 3.2. The reported values do not account for changes in the industry since 2009.

Note: EPA did not have sufficient information in the Steam Electric Survey to determine generation flow rates for 22 plants. Although EPA included these plants in the count of plants generating bottom ash transport water, EPA did not include them in the determination of the average, median, or range of generation flow rates in the table. Additionally, some plants reported that they generated bottom ash transport water but may not have specifed a wet ash handling system in another part of the Steam Electric Survey (see Table 4-9). EPA included these plants in its determination of the generation rates presented in this table.

6.2.3 Ash Transport Water Characteristics

Fly ash and bottom ash transport waters are typically treated in large surface impoundment systems that sometimes comprise multiple impoundments. These impoundments often receive other plant wastewaters along with fly and/or bottom ash transport water. Additionally, plants operating both wet fly ash and wet bottom ash handling systems will often send both fly ash and bottom ash transport waters to the same surface impoundment system. Some plants recycle part or all of the surface impoundment effluent, but most plants discharge the overflow. Untreated ash transport waters contain significant concentrations of TSS and metals. The effluent from ash surface impoundments generally contains low concentrations of TSS; however, metals are still present in the effluent, predominantly in dissolved form.

Surface impoundments are designed to remove particulates from wastewater by gravity. The fly ash, bottom ash, and other solids (*e.g.*, FGD solids) settle out of the wastewater to the bottom of the impoundment. The wastewater must reside in the impoundment long enough to settle the desired particle size. Surface impoundments can effectively reduce TSS in ash transport water, particularly bottom ash transport water, which contains relatively dense ash particles. They also effectively remove some metals from ash transport water when the metals are present in suspended particulate form.

The discharge flow rates from the impoundments are not the same as ash transport water flow rates. The ash transport water flow rate is the amount of the fly and bottom ash transport water that is pumped with the ash to the impoundment over time, while the discharge flow is the amount of the overflow water that is discharged from the impoundment or recycled. Impoundments typically receive wastestreams in addition to bottom ash and fly ash transport waters (*e.g.*, boiler blowdown, cooling water, low volume wastewater). In addition, the impoundment overflow rate is reduced by impoundment losses from infiltration through the bottom of the impoundment or retaining dikes, evaporation, and amount of recycle from the impoundment back to the plant for reuse. Table 6-6 presents the amount of fly ash and bottom ash wastewater discharged in 2009, whereas Table 6-4 and Table 6-5 present the fly ash and bottom ash transport water generation flow rates, respectively. On average, a single plant discharges approximately 3.5 MGD of fly ash transport water and approximately 2.1 MGD of bottom ash transport water. Therefore, on average, the steam electric power generating industry discharges approximately 81 percent of all fly ash transport water generated and 82 percent of all bottom ash transport water generated. Section 7 discusses surface impoundment management practices in place in the steam electric power generating industry.

Table 6-6. Ash Wastewater Discharge for the Steam Electric Power Generating Industry in 2009

Type of Wastewater	Number of Plants Discharging	Average Discharged Wastewater Flow (gpd/plant)
Fly Ash	113	3,480,000
Bottom Ash	283	2,050,000

Source: Steam Electric Survey [ERG, 2015a].

Note: Wastewater flow rates are rounded to three significant figures.

Note: The number of plants and discharge flow rates in the steam electric power generating industry are based on values reported in the Steam Electric Survey for operations in 2009, which were scaled to represent the industry as a whole using the industry-weighting factors discussed in Section 3.2. The reported values do not account for changes in the industry since 2009.

Note: In 2009, 76 plants combined their fly and bottom ash sluice streams into one impoundment or impoundment system, identified as a combined ash impoundment. All 76 plants discharging combined ash wastewater were included in the table and counted as both fly ash and bottom ash dischargers. For these plants, EPA calculated a median percentage of total flow for both fly and bottom ash sluice and used the percentages to calculate a fly and bottom ash contribution for all combined ash wastewater flows. The median fly ash wastewater contribution is 60.3 percent and the median bottom ash contribution is 39.7 percent.

The design, operation, and maintenance of impoundments in the steam electric power generating industry vary by plant/company. As described above, impoundments are designed to remove TSS; therefore, the size of the impoundment depends upon the combined flow rate of the influent wastestreams, as well as the settling properties of the solids in the wastestreams. Some plants may add chemicals to the impoundment effluent to control the pH of the discharge. The Steam Electric Power Generating Effluent Limitations Guidelines and Standards (ELGs) limit the pH of all discharged wastestreams to a range of 6.0 to 9.0 S.U. Common chemicals used to control the pH in impoundments are sodium hydroxide and hydrochloric acid.

EPA collected a wastewater sample representing the influent to a fly ash impoundment at the Cardinal plant during EPA's detailed study of the industry. EPA also used industry-supplied data and publicly available data sources, including data received during public comments, to characterize fly ash and bottom ash transport water, including samples representative of untreated/raw ash transport water, partially treated ash transport water, and ash impoundment effluent. The data set of untreated ash transport samples is very small and typically represents some amount of settling[37]. Based on the information EPA collected, fly ash transport water generally contains TSS, TDS, sulfate, chloride, sodium, calcium, copper, and selenium. Bottom ash transport generally contains TSS, TDS, sulfate, sulfite, chloride, and metals, including sodium, calcium, and magnesium.

6.3 Combustion Residual Leachate from Landfills and Surface Impoundments

Plants generating FGD wastewater and ash transport water generally send the wastewater to a surface impoundment or wastewater treatment system. The FGD solids and ash sent to a surface impoundment may be stored permanently in the impoundment or dredged from the impoundment and transferred to a landfill. Solids collected in FGD wastewater treatment systems are typically disposed of in a landfill. Additionally, plants may send the fly ash, bottom ash, and FGD residuals (*i.e.*, gypsum or calcium sulfite) directly to a landfill without first sending them to a surface impoundment. Water that comes in contact with the combustion residuals that are stored in these management units will be contaminated by metals and other contaminants present in the combustion residuals. As discussed in Section 4.3.5, combustion residual leachate includes the liquid and any suspended or dissolved constituents in the liquid that has percolated through or drained from waste or other materials placed in a landfill, or that passes through the containment structure (*e.g.*, bottom, dikes, berms) of a surface impoundment. Combustion residual leachate includes seepage and/or leakage from a combustion residual landfill or impoundment unit and also includes wastewater from landfills and surface impoundments located on non-adjoining property when under the operational control of the permitted facility. The following section describes the estimated amount of combustion residual leachate generated by the steam electric power generating industry and the characteristics of this wastestream.

Part F of EPA's Steam Electric Survey requested information on the management practices of both impoundments and landfills containing combustion residuals, including information about how the combustion residual leachate is collected and treated. As described in Section 3.2, EPA sent Part F to a subset of coal- and petroleum coke-fired power plants, and used information from this subset to estimate the total number of plants in the steam electric power generating industry generating combustion residual leachate. Table 6-7 presents the total estimated number of plants generating leachate in the steam electric power generating industry from either an active or inactive impoundment or landfill. As defined in the survey, an inactive landfill or impoundment is a management unit that is currently not r;eceiving waste but is still capable of receiving waste in the future and therefore, subject to the final rule. EPA estimates that, in 2009, 150 to 200 coal-fired and petroleum coke-fired steam electric plants generated on average 0.57 MGD per plant of combustion residual leachate.

[37] Due to the limited amount of untreated ash transport water data available, EPA also used partially treated and treated ash transport water samples for the identification of pollutants of concern, as described later in Section 6.6.4.

Table 6-7. Combustion Residual Leachate Flow Rates for the Steam Electric Power Generating Industry in 2009

Combustion Residual Management Unit	Unit Operating Status	Number of Plants [a]	Average Flow Rate	Median Flow Rate	Range of Flow Rate
Flow Rate per Plant (gpd/plant)					
Landfill	Active/Inactive	110-120	239,000	202,000	11,700-1,480,000
Impoundment	Active/Inactive	100-110	826,000	176,000	170-7,880,000
Total		**150-200**	**574,000**	**157,000**	**693-7,880,000**

Source: Steam Electric Survey [ERG, 2015a].

Note: Wastewater flow rates are rounded to three significant figures.

Note: Certain fields contain ranges of values to protect the release of information claimed confidential business information (CBI).

Note: Part F of the Steam Electric Survey was distributed to 97 plants. The responses from these plants were weighted to reflect the number of plants and the volume of leachate generated in the industry. The number of plants generating leachate is based on values reported in the Steam Electric Survey for operations in 2009, which were scaled to represent the industry as a whole using the industry-weighting factors discussed in Section 3.2. The reported values do not account for changes in the industry since 2009.

Note: EPA did not have sufficient information in the Steam Electric Survey to determine the generation flow rates for 31 plants collecting combustion residual leachate from landfills and 32 plants collecting combustion residual leachate from impoundments. Although EPA included these plants in the count of plants generating combustion residual leachate, EPA did not include them in the determination of the average, median, or range of generation flow rates in the table.

a – Some plants may have more than one landfill or impoundment management unit.

Table 6-8 presents the number of coal-fired and petroleum coke-fired plants that discharged combustion residual leachate in 2009. The amount of combustion residual leachate discharged by the steam electric power generating industry is less than the amount of combustion residual leachate generated, as shown in Table 6-1 through Table 6-7. The combustion residual leachate collected is generally transferred to a collection impoundment. Once collected, the combustion residual leachate can be recycled back into the management unit or recycled elsewhere within the plant, sent to an on-site treatment system, or discharged. More than half of the plants generating combustion residual leachate from surface impoundments recycle the wastestream [ERG, 2015a]. Section 7.4 provides more detail on the types of leachate treatment technologies.

Table 6-8. Combustion Residual Leachate Discharged for the Steam Electric Power Generating Industry in 2009

Combustion Residual Management Unit	Unit Operating Status	Number of Plants	Average Discharged Wastewater Flow (gpd/plant)
Landfill	Active/Inactive	90-100	70,000-80,000
Impoundment	Active/Inactive	30-40	70,000-80,000
Total		**100-110**	**80,000-90,000**

Source: Steam Electric Survey [ERG, 2015a].

Note: Wastewater flow rates are rounded to three significant figures.

Note: Certain fields contain ranges of values to protect the release of information claimed confidential business information (CBI).

Note: The number of plants and discharge flow rates in the steam electric power generating industry are based on values reported in the Steam Electric Survey for operations in 2009, which were scaled to represent the industry as a whole using the industry-weighting factors discussed in Section 3.2. The reported values do not account for changes in the industry since 2009.

Note: EPA did not have sufficient information in the Steam Electric Survey to determine the discharge flow rates for one plant collecting combustion residual leachate from landfills and two plants collecting combustion residual leachate from impoundments. Although EPA included these plants in the count of plants discharging combustion residual leachate, EPA did not include them in the determination of the average discharge flow rate.

As part of the Steam Electric Survey, EPA requested that a subset of plants provide sampling data for untreated landfill and/or impoundment leachate collected at the plant. EPA received data from active and inactive landfills and impoundments, which were used to characterize the combustion residual leachate generated by the steam electric power generating industry. Table 6-9 presents the average pollutant concentrations for combustion residual leachate, which represents both landfills and impoundments. Combustion residual leachate contains concentrations of chloride, sulfate, TDS, TSS, calcium, sodium, and magnesium that are at least one magnitude higher than other pollutants in the wastestream. The pollutants in the leachate are generally at lower concentrations than those seen in FGD wastewater and ash transport water.

Table 6-9. Average Pollutant Concentrations of Combustion Residual Leachate

Analyte	Units	Average Total Concentration
Classicals		
Chloride	ug/L	413,000
Sulfate	ug/L	1,790,000
TDS	ug/L	3,500,000
TSS	ug/L	35,800
Metals, Metalloids, and other Nonmetals		
Aluminum	ug/L	2,990
Antimony	ug/L	3.75
Arsenic	ug/L	38.4
Barium	ug/L	53.2
Beryllium	ug/L	1.33
Boron	ug/L	22,400
Cadmium	ug/L	10.1
Calcium	ug/L	408,000
Chromium	ug/L	2,120
Cobalt	ug/L	38.6
Copper	ug/L	7.58
Iron	ug/L	37,100
Lead	ug/L	2.37
Magnesium	ug/L	118,000
Manganese	ug/L	2,720

Table 6-9. Average Pollutant Concentrations of Combustion Residual Leachate

Analyte	Units	Average Total Concentration
Mercury	ug/L	1.06
Molybdenum	ug/L	1,380
Nickel	ug/L	46.5
Selenium	ug/L	111
Silver	ug/L	1.63
Sodium	ug/L	308,000
Thallium	ug/L	1.16
Tin	ug/L	49.3
Titanium	ug/L	13.6
Vanadium	ug/L	1,910
Zinc	ug/L	211

Source: Steam Electric Survey [ERG, 2015a].
Note: Concentrations are rounded to three significant figures.

6.4 FLUE GAS MERCURY CONTROL WASTEWATER

As described in Section 4.3.4, there are two types of systems used to control flue gas mercury emissions: adding oxidizing agents to the coal prior to combustion and injecting activated carbon into the flue gas after combustion. Adding oxidizing agents prior to combustion does not generate a new wastewater stream; however, activated carbon injection (ACI) systems have the potential to generate a FGMC wastestream, depending on the location of the sorbent injection. If the injection occurs upstream of the primary particulate removal system, then the mercury-containing carbon (*i.e.*, FGMC waste) will be collected and handled the same way as the fly ash; therefore, if the fly ash is wet sluiced, then the FGMC wastes are also wet sluiced. When the activated carbon is injected downstream of the primary particulate removal system, the FGMC waste must be collected in a separate particulate removal system, typically a fabric filter baghouse. Residual fly ash that passes through the primary particulate removal system may also be captured.

The FGMC waste and fly ash can either be handled using a wet-sluicing system or a dry handling system. There are 15 plants with at least one ACI system injecting carbon downstream of the primary particulate removal system. Six of these plants identified the FGMC system as planned and installed after 2009. Of these 15 plants, only one planned to handle the FGMC waste using a wet-sluicing system; however, this plant planned to send the FGMC waste to a zero discharge impoundment, where the impoundment overflow will be reused for fly ash, bottom ash, and FGMC transport water [ERG, 2015a].

For ACI systems in which the carbon is injected upstream of the primary particulate control system, the FGMC waste is collected with fly ash. Again, this can be handled either wet or dry, depending on how the plant is handling the fly ash. There are 58 plants with at least one ACI system injecting carbon upstream of the primary particulate system. Fourteen of these plants identified the FGMC system as planned and installed after 2009. Of these 58 plants, five (three with current systems and two with planned systems) reported handling the FGMC waste using a wet-sluicing system.

EPA's ORD evaluated the effects of these ACI systems on the characteristics of fly ash and determined that these systems substantially increase the total mercury content of the fly ash [U.S. EPA, 2006]. ORD looked at six plants, four operating ACI systems and two operating brominated ACI systems.[38] ORD collected fly ash from these plants, with and without FGMC waste, and analyzed it for mercury, arsenic, and selenium. ORD concluded that, of the three constituents analyzed, FGMC waste significantly affects only the mercury concentration of fly ash. Five of the six plants showed an increase in the mercury concentration of fly ash with FGMC waste as compared to fly ash alone [U.S. EPA, 2006]. Table 6-10 shows the distribution of mercury concentrations at each of the six plants.

Table 6-10. Mercury Concentrations in Fly Ash With and Without ACI Systems

Plant	Mercury (EPA Method 3052)			Mercury (EPA Method 7473)		
	Fly Ash Only (ng/g)	With ACI (ng/g)	Percent Increase	Fly Ash Only (ng/g)	With ACI (ng/g)	Percent Increase
Brayton Point	651	1,530	135%	582	1,414	143%
Pleasant Prairie	158	1,180	648%	147	1,177	701%
Salem Harbor	529	412	-22%	574	454	-21%
Facility C	16	1,151	7,094%	11	1,090	9,810%
St. Clair [a]	111	1,163	949%	NT	NT	NA
Facility L (Run 1) [a]	13	38	190%	NT	NT	NA
Facility L (Run 2) [a]	20	71	252%	NT	NT	NA

Source: [U.S. EPA, 2006].

Note: ORD analyzed mercury using two different analytical methods, EPA Method 3052 and EPA Method 7473. Both results are shown in the table.

NT – Not tested.

NA – Not applicable.

a – Plant operates a brominated activated carbon injection system.

6.5 GASIFICATION WASTEWATER

As discussed in Section 4.3.6, there are several wastestreams generated at integrated gasification combined cycle (IGCC) plants that comprise gasification wastewater. Figure 4-4 depicts the general process flow diagram for the IGCC process. Gasification wastewater includes wastewater from all sources of an IGCC process (except those for which specific limitations or standards are otherwise established). Gasification wastewater includes, but is not limited to slag handling wastewater; fly ash and water stream; sour/grey water (which consists of condensate generated for gas cooling, as well as other wastestreams); CO2/steam stripper wastewater; and

[38] The chloride content of flue gas can affect the performance of activated carbon systems, low chloride concentrations can yield low mercury removal. Some plants with low chloride levels utilize brominated activated carbon as a sorbent to increase the amount of mercury captured [U.S. EPA, 2006].

sulfur recovery unit blowdown. Air separation unit blowdown and runoff from fuel and/or byproduct piles are not considered gasification wastewater.

As part of the CWA 308 monitoring program described in Section 3.4.1, EPA collected data from two plants operating IGCC systems. Both plants, Tampa Electric Company's Polk Station (Polk) and Wabash Valley Power Association's Wabash River Station (Wabash River), treat their gasification wastewater with an evaporation system. Both plants sampled the influent streams transferred to the evaporation system and the distillate/condensate(s) from the systems. EPA used the influent data from both plants to characterize untreated gasification wastewater. Table 6-11 provides the individual average concentrations of the untreated gasification wastewater for the two plants, as well as the combined average for both plants.

Table 6-11. Untreated Gasification Wastewater Concentrations

Analyte	Units	Polk Concentration	Wabash River Concentration	Average Polk and Wabash River Concentration
Classicals				
Ammonia as Nitrogen	mg/L	175	35	105
Nitrate Nitrite as N	mg/L	0.09	0.05	0.07
Nitrogen, Kjeldahl	mg/L	603	65	334
Biochemical Oxygen Demand	mg/L	7.7	205	106
Chemical Oxygen Demand	mg/L	101	823	462
Chloride	mg/L	1,300	1,050	1,175
Sulfate	mg/L	2,750	11	1,380
Total Dissolved Solids	mg/L	4,575	4,225	4,400
Total Suspended Solids	mg/L	16	2.0	8.9
Phosphorus, Total	mg/L	0.47	0.19	0.33
Metals, Metalloids, and Other Nonmetals				
Aluminum	ug/L	11,475	100	5,788
Antimony	ug/L	363	1.0	182
Arsenic	ug/L	280	4	142
Barium	ug/L	118	10	64
Beryllium	ug/L	14	1.0	7.3
Boron	ug/L	38,250	34,750	36,500
Cadmium	ug/L	4.1	2.0	3.0
Calcium	ug/L	19,450	783	10,116
Chromium	ug/L	4.0	4.0	4.0
Cobalt	ug/L	10	10	10
Copper	ug/L	2.0	2.0	2.0
Cyanide, Total	mg/L	1.4	2.3	1.8
Iron	ug/L	2,115	1,140	1,628
Lead	ug/L	18	1.0	10
Magnesium	ug/L	5,325	200	2,763
Manganese	ug/L	238	10	124

Table 6-11. Untreated Gasification Wastewater Concentrations

Analyte	Units	Polk Concentration	Wabash River Concentration	Average Polk and Wabash River Concentration
Mercury	ng/L	70	4.3	37
Molybdenum	ug/L	49	20	35
Nickel	ug/L	4,950	2.0	2,476
Selenium	ug/L	1,278	920	1,099
Silver	ug/L	1.0	1.0	1.0
Sodium	ug/L	1,675,000	1,850,000	1,762,500
Thallium	ug/L	254	3	129
Tin	ug/L	100	100	100
Titanium	ug/L	19	10	15
Vanadium	ug/L	280	16	148
Zinc	ug/L	77	20	49

Source: Steam Electric Analytical Database for the Final Rule [U.S. EPA, 2015d].

6.6 POLLUTANTS OF CONCERN

Constituents present in combustion wastewater are primarily derived from the parent carbon feedstock (*e.g.*, coal, petroleum coke). EPA evaluated the combustion wastewater characteristics generated by the industry and identified POCs for each of the regulated wastestreams. The POC analysis preferentially uses samples of untreated wastewater; however, where EPA lacked data on specific pollutants, it supplemented the dataset with partially treated or treated samples as appropriate for the wastestream.

The extent of data available to characterize each of the regulated wastestreams varies. EPA conducted a field sampling program and Steam Electric Survey as part of the rulemaking efforts for the Steam Electric Power Generating ELGs and in part, from the detailed study preceding these efforts. EPA also collected data from industry and from publicly available sources. Combined, EPA used these data sources to characterize the wastestreams generated by the industry. EPA subjected all data to the data quality review criteria for sampling data, questionnaire data, and secondary data, as described in the "Development Memorandum for Steam Electric Analytical Database for the Final Rule" [ERG, 2015e]. EPA reviewed each data source to determine if the data met EPA's criteria for use in characterizing in-process wastestreams for the purpose of identifying POCs. The following general criteria applied across all wastestreams:

- Sample must be representative of typical full-scale plant operations (*e.g.*, not samples of wastewater evaluated on a pilot or bench scale).
- Sample descriptions and locations must be unambiguous and clearly described such that it can be categorized by wastestream type (*e.g.*, FGD purge, bottom ash impoundment influent) and by level of treatment (*e.g.*, untreated, partially treated). For fly ash and bottom ash transport water wastestreams, the sample location must comprise at least 75 percent by volume fly ash or bottom ash transport water.

- Sample analysis must be completed using accepted analytical methods for wastewater.
- Sample results must contain sufficient information (*e.g.*, non-detects must contain method detection limits or quantitation limits, data qualifiers where needed, information to identify units).
- Source water sample data that are paired with wastewater sample data must be taken within a day the wastewater sample collection date.
- Data must not be duplicative of other accepted data. Where duplicate data exists (*e.g.*, submitted by a trade association representing individual plants and also submitted by the individual plant), EPA used only accepted data collected from the individual plant.

The following sections discuss the POCs identified for each of the regulated wastestreams, and where relevant, any additional data editing criteria EPA applied to develop the data set used for the analysis. The POCs identified for each wastestream are used as the basis for calculating pollutant loadings, described in Section 10, and the selection of regulated pollutants, described in Section 11.

6.6.1 FGD Wastewater POCs

As described in ERG's memorandum *FGD Wastewater, Combustion Residual Leachate, and Gasification Wastewater Pollutants of Concern (POC) Analysis Methodology* [ERG, 2015f], EPA reviewed data sources containing information on untreated FGD wastewater using the general data quality review criteria described earlier in this section. EPA used the following data sources that met the criteria to identify POCs in untreated FGD wastewater [U.S. EPA, 2015f]:

- EPA Field Sampling Program. As part of the sampling program, EPA collected four samples of untreated FGD wastewater from seven steam electric power plants operating FGD wastewater treatment systems. EPA analyzed a total of 28 samples for 38 analytes. Section 3.4.1 discusses the analytes evaluated in the EPA sampling program.
- EPA CWA 308 Monitoring Program. EPA required eight plants to participate in the CWA 308 monitoring program and required each plant to collect three to four samples of untreated FGD wastewater. EPA analyzed a total of 31 samples for 37 analytes (not including hexavalent chromium).
- Steam Electric Public Comments on the Proposed Rulemaking. EPA received analytical data on untreated FGD wastewater from one plant as part of their public comment submission. The plant submitted analytical results representing a total of 159 samples for arsenic, mercury, and selenium.
- EPA Data Requests. In EPA's data requests to specific plants for information on FGD wastewater treatment, three plants submitted analytical data on untreated FGD wastewater. The plants submitted analytical results representing a total of 189 samples for ammonia, arsenic, mercury, nitrate-nitrite as N, and selenium.

For wastestreams where the final rule establishes numeric effluent limits, the POCs are those pollutants that have been quantified in a wastestream at sufficient frequency at treatable levels (concentrations). EPA reviewed data for the untreated FGD wastewater to identify pollutants detected at greater than or equal to 10 times the quantitation limit in at least 10 percent of all samples.

EPA used the sample-specific quantitation limit as an indicator of the pollutants present in FGD wastewater because it provides a direct comparison to the sample result. The quantitation limit is sample-specific and accounts for analytical adjustments made in the determination of the sample result. Additionally, using 10 times the quantitation limit as a screening threshold ensures the influent concentrations are high enough to quantify the degree of pollutant removal following treatment processes. EPA used all available untreated FGD wastewater data that met the data acceptance criteria in the POC analysis except seven samples, which did not contain quantitation limits. Table 6-12 lists the 31 POCs identified for FGD wastewater.

Table 6-12. Pollutants of Concern – FGD Wastewater

Pollutant Group	Pollutant of Concern
Conventional Pollutants	Total Suspended Solids
Priority Pollutants	Antimony
	Arsenic
	Beryllium
	Cadmium
	Chromium
	Copper
	Cyanide, Total
	Lead
	Mercury
	Nickel
	Selenium
	Thallium
	Zinc
Nonconventional Pollutants	Aluminum
	Ammonia as Nitrogen
	Barium
	Boron
	Calcium
	Chloride
	Cobalt
	Iron
	Magnesium
	Manganese
	Molybdenum
	Nitrate Nitrite as N

Table 6-12. Pollutants of Concern – FGD Wastewater

Pollutant Group	Pollutant of Concern
	Phosphorus
	Sodium
	Titanium
	Total Dissolved Solids
	Vanadium

Source: FGD Wastewater, Combustion Residual Leachate, and Gasification Wastewater Pollutants of Concern (POC) Analysis Methodology [ERG, 2015f].
Note: Oil and grease is regulated under the previously promulgated best practicable control technology currently available (BPT) for low volume waste sources, which covered FGD wastewater. EPA did not collect data for oil and grease and does not have data available to identify it as a POC for FGD wastewater.

6.6.2 Combustion Residual Leachate POCs

As part of the Steam Electric Survey, EPA required a subset of plants to sample their leachate from impoundments and landfills containing combustion residuals. EPA used the combustion residual leachate data collected from the survey responses to identify POCs for the wastestream. The data EPA used in the analysis included 246 samples for 30 analytes. EPA excluded data from retired or closed units for use in this analysis because combustion residual leachate from retired units is not regulated in the final rule. Similar to the POC analysis for FGD wastewater described in Section 6.6.1, EPA reviewed the data for untreated combustion residual leachate to identify pollutants detected at greater than or equal to 10 times the quantitation limit in at least 10 percent of all samples [ERG, 2015f]. Table 6-13 lists the 25 POCs identified for combustion residual leachate.

Table 6-13. Pollutants of Concern – Combustion Residual Leachate

Pollutant Group	Pollutant of Concern
Conventional Pollutants	Total Suspended Solids
Priority Pollutants	Antimony
	Arsenic
	Cadmium
	Chromium
	Copper
	Mercury
	Nickel
	Selenium
	Thallium
	Zinc
Nonconventional Pollutants	Aluminum
	Barium
	Boron
	Calcium
	Chloride
	Cobalt
	Iron
	Magnesium
	Manganese
	Molybdenum
	Sodium
	Sulfate
	Total Dissolved Solids
	Vanadium

Source: FGD Wastewater, Combustion Residual Leachate, and Gasification Wastewater Pollutants of Concern (POC) Analysis Methodology [ERG, 2015f].
Note: Oil and grease is regulated under the previously promulgated BPT for low volume waste sources, which covered combustion residual leachate wastewater. EPA did not collect data for oil and grease and does not have data available to identify it as a POC for combustion residual leachate.

6.6.3 <u>Gasification Wastewater POCs</u>

EPA sampled wastewater streams at two plants operating IGCC generating units as part of the CWA 308 sampling program discussed in Section 3.4. EPA reviewed the data for untreated gasification wastewater from these two steam electric power plants and all data, 20 samples for 37 analytes, met the data acceptance criteria and were used to evaluate POCs. Similar to the POC analysis for FGD wastewater described in Section 6.6.1, EPA identified pollutants detected at greater than or equal to 10 times the quantitation limit in at least 10 percent of all samples [ERG, 2015f]. Table 6-14 lists the 34 POCs identified for gasification wastewater.

Table 6-14. Pollutants of Concern – Gasification Wastewater

Pollutant Group	Pollutant of Concern
Conventional Pollutants	Biochemical Oxygen Demand
	Total Suspended Solids
Priority Pollutants	Antimony
	Arsenic
	Beryllium
	Cadmium
	Copper
	Lead
	Mercury
	Nickel
	Selenium
	Thallium
	Cyanide, Total
	Zinc
Nonconventional Pollutants	Aluminum
	Ammonia as Nitrogen
	Barium
	Boron
	Calcium
	Chemical Oxygen Demand
	Chloride
	Cobalt
	Iron
	Magnesium
	Manganese
	Molybdenum
	Nitrate Nitrite as N
	Nitrogen, Kjeldahl
	Sodium
	Sulfate
	Titanium
	Total Dissolved Solids
	Phosphorus, Total
	Vanadium

Source: FGD Wastewater, Combustion Residual Leachate, and Gasification Wastewater Pollutants of Concern (POC) Analysis Methodology [ERG, 2015f].

6.6.4 Ash Transport Water POCs

As described in the memorandum, "Bottom Ash and Fly Ash Transport Water Pollutants of Concern (POC) Analysis Methodology" [ERG, 2015h], EPA reviewed data sources containing information on bottom ash transport water and fly ash transport water using the general data quality review criteria described earlier in this section, as well as more specific criteria listed in the memorandum. Bottom ash and fly ash transport water data primarily consist of secondary data sources. EPA did not collect data through the EPA field sampling program or the Steam Electric Survey. EPA's review of the ash data sources is detailed in "Ash Analytical Data Review Memorandum" [ERG, 2015g].

EPA used the following data sources that met the criteria to identify POCs for bottom ash and fly ash transport water [ERG, 2015h]:

- Data Collected from Utilities. EPA received various forms of analytical data submitted from plants or electric power companies as part of the public comments on the proposed rulemaking and in responses to the Steam Electric Survey. Data submitted in public comment by Hoosier Energy and Duke Energy and survey data submitted by Interstate Power and Light Company met EPA's data acceptance criteria and were used in the analysis. These data are:
  - 147 paired source water and fly ash pond samples from two plants.
  - 195 paired source water and bottom ash transport water samples from 7 plants.
  - 5 non-paired bottom ash samples from one plant.
- Industry Trade Association Data. EPA coordinated with UWAG to collect ash transport water data from its member companies that was submitted to EPA during the detailed study and in public comments on the proposed rulemaking. EPA also obtained reports containing ash transport water data from EPRI, including the Plant Integrated Systems: Chemical Emissions Studies (PISCES) Reports and other EPRI-published reports provided by plants in responses to the Steam Electric Survey. Data accepted for the ash transport water POC analysis are:
  - 153 paired fly ash and source water samples from four plants.
  - 189 paired bottom ash and source water samples from eleven plants.
  - 260 non-paired fly ash samples from three plants.
  - 16 non-paired bottom ash samples from eight plants.
- Previously Collected EPA Data. EPA collected data on ash transport water data during the 1982 Steam Electric Rulemaking and during the 2009 Steam Electric Detailed Study. Data accepted for the ash transport water POC analysis are:
  - 28 paired fly ash and source water samples from three plants.
  - 27 paired bottom ash and source water samples from three plants.
  - 1 non-paired fly ash sample from one plant.
  - 1 non-paired bottom ash sample from one plant.

EPA included data for fly ash and bottom ash transport water samples but did not include combined ash transport water samples in the POC analysis.[39] Due to the limited data set for untreated fly and bottom ash transport water, EPA also included samples representing partially treated ash transport water and ash impoundment effluent to identify POCs for this wastestream.

For wastestreams where EPA is establishing zero discharge (*i.e.*, fly ash transport water, bottom ash transport water, and FGMC wastewater), the POCs identified for each wastestream are those pollutants that are confirmed to be present at sufficient frequency in untreated wastewater samples of that wastestream. Because EPA did not need to identify pollutants at a treatable level, EPA determined partially treated and ash impoundment effluent data were acceptable for use in the POC analysis.

As shown above, for some of the data, industry also supplied paired source water data to demonstrate that the source water used for ash sluicing may contribute to the pollutants present in untreated ash transport water. Where paired source water and ash transport water samples were available, EPA reviewed data for the paired source water and ash transport water to identify pollutants detected at greater than or equal to two times the concentration of the source water at 10 percent or more of all plants with paired samples. EPA used two times the source water concentration for the analysis because it sufficiently indicates the pollutant is present in concentrations above the source water concentrations. Where paired source water and ash transport water data were not available or did not sufficiently indicate the presence of the pollutant in ash transport water, EPA reviewed data for ash transport water without paired source water data and identified pollutants detected at greater than or equal to two times the pollutant's baseline values at 10 percent or more of all plants with unpaired samples. EPA used baseline values from the *Development Document for Effluent Limitations Guidelines and Standards for the Centralized Waste Treatment Industry* [U.S. EPA, 2000]. Table 6-15 and Table 6-16 present the final list of POCs for fly ash transport water and bottom ash transport water, respectively. EPA identified 38 POCs for fly ash transport water and 37 POCs for bottom ash transport water.

Table 6-15. Pollutants of Concern – Fly Ash Transport Water

Pollutant Group	Pollutant of Concern
Conventional Pollutants [a]	Total Suspended Solids
	Chemical Oxygen Demand
Priority Pollutants	Arsenic
	Beryllium
	Cadmium
	Chromium
	Copper
	Lead
	Mercury
	Nickel

[39] As described in Section 10.2.2, EPA evaluated the pollutants present in combined ash impoundments, calculated average pollutant concentrations in combined ash impoundment effluent, and included combined ash ponds in the pollutant loadings calculation.

Table 6-15. Pollutants of Concern – Fly Ash Transport Water

Pollutant Group	Pollutant of Concern
	Selenium
	Thallium
	Zinc
Nonconventional Pollutants	Aluminum
	Ammonia (as N) [b]
	Barium
	Boron
	Calcium
	Chloride
	Cobalt
	Fluoride
	Iron
	Magnesium
	Manganese
	Molybdenum
	Nitrate Nitrite (as N)
	Nitrogen, Total Kjeldahl (TKN)
	Phosphorus
	Potassium
	Silica
	Sodium
	Strontium
	Sulfate
	Titanium
	Total Dissolved Solids
	Vanadium
	Yttrium

Source: Bottom Ash and Fly Ash Transport Water Pollutants of Concern (POC) Analysis Methodology [ERG, 2015h].

a – EPA did not evaluate data on oil and grease because it is already adequately controlled by BPT regulations.

b – EPA identified ammonia (as N) as a POC; however, EPA excluded this POC from the calculation of pollutant loads to avoid double counting of nitrogen compounds.

Table 6-16. Pollutants of Concern – Bottom Ash Transport Water

Pollutant Group	Pollutant of Concern
Conventional Pollutants [a]	Total Suspended Solids
	Chemical Oxygen Demand
Priority Pollutants	Antimony
	Arsenic

Table 6-16. Pollutants of Concern – Bottom Ash Transport Water

Pollutant Group	Pollutant of Concern
	Bromide
	Cadmium
	Chromium
	Copper
	Lead
	Mercury
	Nickel
	Selenium
	Thallium
	Zinc
Nonconventional Pollutants	Aluminum
	Ammonia (as N) [b]
	Barium
	Boron
	Calcium
	Chloride
	Cobalt
	Iron
	Magnesium
	Manganese
	Molybdenum
	Nitrate Nitrite (as N)
	Nitrogen, Total Kjeldahl (TKN)
	Phosphorus
	Potassium
	Silica
	Sodium
	Strontium
	Sulfate
	Sulfite
	Titanium
	Total Dissolved Solids
	Vanadium

Source: Bottom Ash and Fly Ash Transport Water Pollutants of Concern (POC) Analysis Methodology [ERG, 2015h].

a – EPA did not evaluate data on oil and grease because it is already adequately controlled by BPT regulations.

b – EPA identified ammonia (as N) as a POC; however, EPA excluded this POC from the calculation of pollutant loads to avoid double counting of nitrogen compounds.

6.6.5 Flue Gas Mercury Control Wastewater POCs

The FGMC waste (fly ash) can be handled using either a wet-sluicing system or dry handling system. Based on responses to the Steam Electric Survey, EPA determined that more plants are operating ACI systems injecting the carbon upstream of the primary particulate removal system compared to downstream injection. Additionally, EPA determined that there are more plants operating wet-sluicing systems for upstream carbon injection compared to downstream injection. Based on these data, EPA determined that the majority of plants generating FGMC wastewater are collecting the FGMC waste with the bulk of the fly ash removed from the flue gas.

EPA was unable to obtain readily available data for identifying the POCs in FGMC wastewater. Nevertheless, based on process knowledge and engineering judgment, EPA concluded that the POCs for FGMC wastewater are likely to be identical to the POCs identified for fly ash transport water. As described in Section 6.4, EPA's review of fly ash with and without FGMC waste showed that FGMC waste did not alter the characteristics of the fly ash characteristics in two of the three analytes, with arsenic and selenium remaining similar and an increase in mercury concentrations with FGMC waste. Thus, EPA concluded that FGMC waste would exhibit similar characteristics as fly ash. Based on this conclusion, EPA identified 38 POCs associated with FGMC wastewater. Table 6-17 lists the POCs identified for FGMC wastewater, which is the same as the list for fly ash transport water (see Table 6-15).

Table 6-17. Pollutants of Concern – FGMC Wastewater

Pollutant Group	Pollutant of Concern
Conventional Pollutants [a]	Total Suspended Solids
Priority Pollutants	Antimony
	Arsenic
	Beryllium
	Cadmium
	Chromium
	Copper
	Lead
	Mercury
	Nickel
	Selenium
	Thallium
	Zinc
Nonconventional Pollutants	Aluminum
	Ammonia as Nitrogen
	Barium
	Boron
	Calcium
	Chloride
	Cobalt

Table 6-17. Pollutants of Concern – FGMC Wastewater

Pollutant Group	Pollutant of Concern
	Fluoride
	Hexavalent Chromium
	Iron
	Magnesium
	Manganese
	Molybdenum
	Nitrate Nitrite as N
	Nitrogen, Kjeldahl
	Nitrogen, Total Organic (as N)
	Silica
	Sodium
	Sulfate
	Titanium
	Total Dissolved Solids
	Phosphorus, Total
	Vanadium
	Yttrium

Source: Bottom Ash and Fly Ash Transport Water Pollutants of Concern (POC) Analysis Methodology [ERG, 2015g].
a – EPA did not evaluate data on oil and grease because it is already adequately controlled by BPT regulations.

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SECTION 7 TREATMENT TECHNOLOGIES AND WASTEWATER MANAGEMENT PRACTICES

This section provides an overview of treatment technologies and wastewater management practices at steam electric power plants for flue gas desulfurization (FGD) wastewater, fly ash and bottom ash handling wastewater, combustion residual landfill leachate, gasification wastewater, and flue gas mercury control (FGMC) wastewater. This section presents information based on the *Questionnaire for the Steam Electric Power Generating Effluent Guidelines* (Steam Electric Survey), industry profile changes (see Section 4.5), and additional industry-provided information; therefore, all figures, tables, and values provided represent the steam electric power plant population EPA evaluated for the ELGs.

7.1 FGD Wastewater Treatment Technologies and Management Practices

During the Steam Electric Power Generating detailed study and rulemaking, EPA identified 139 steam electric power plants that generate FGD wastewater; 88 (63 percent) of these plants discharge FGD wastewater after treatment. EPA identified and investigated wastewater treatment systems operated by steam electric power plants discharging FGD wastewater, as well as operating/management practices that plants use to reduce the pollutants associated with FGD wastewater discharges. This section provides a detailed description of each of the treatment technologies and management practices listed below.

- *Surface Impoundments*: Surface impoundments (*e.g.*, settling ponds) remove particulates from wastewater by means of gravity. Impoundments are typically sized to allow for a certain residence time within the impoundment to facilitate removing total suspended solids (TSS).
- *Chemical Precipitation*: In chemical precipitation systems, the wastewater is treated in tanks. Chemicals are added to help remove suspended solids and dissolved solids, particularly metals. The precipitated solids are then removed from solution by coagulation/flocculation followed by clarification and/or filtration.
- *Biological Treatment*: EPA identified three types of biological treatment systems currently used to treat FGD wastewater, including anoxic/anaerobic fixed-film bioreactors (that target removals of nitrogen compounds and selenium), anoxic/anaerobic suspended growth systems (that target removals of selenium and other metals), and aerobic/anaerobic sequencing batch reactors (that target removals of organics and nutrients).
- *Vapor-Compression Evaporation System (Evaporation)*: This type of system uses a falling-film evaporator (or brine concentrator), following a pretreatment step, to produce a concentrated wastewater stream and a distillate stream to reduce wastewater by 80 to 90 percent and reduce the discharge of pollutants. The concentrated wastewater is usually further processed in a crystallizer. This treatment system is referred to throughout the TDD as evaporation.

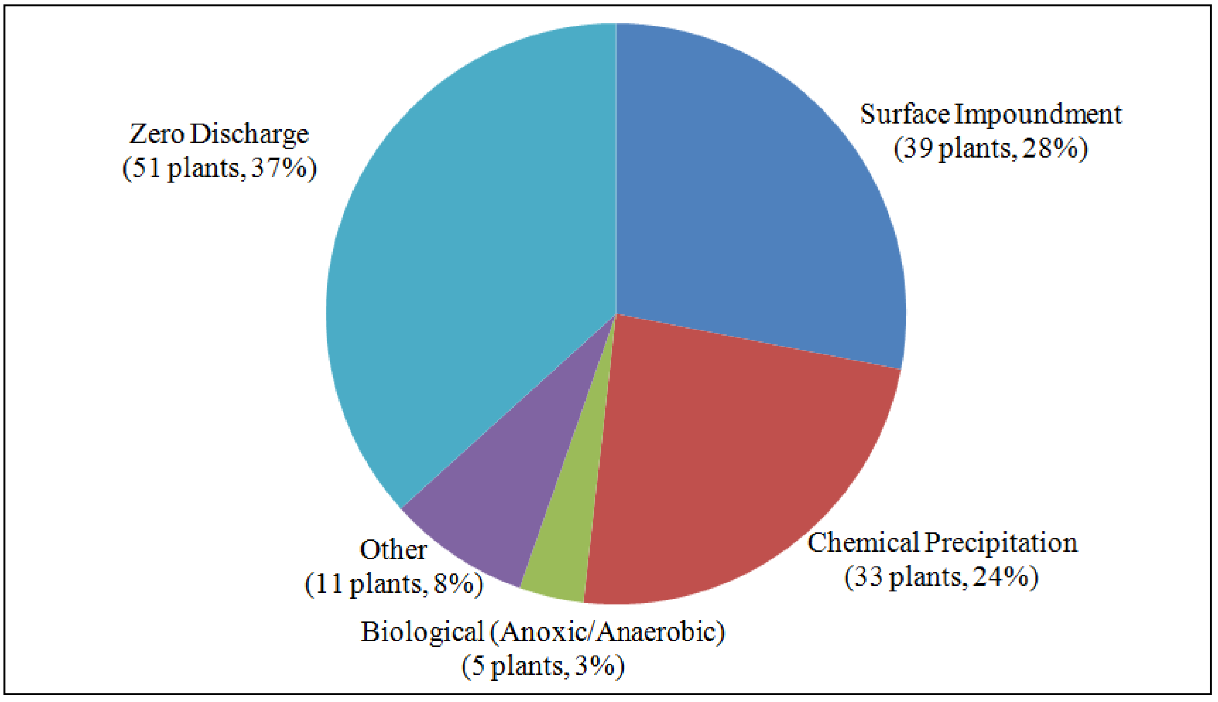
- *Constructed Wetlands*: Constructed wetlands are engineered systems that use natural biological processes involving wetland vegetation, soils, and microbial activity to reduce the concentrations of metals, nutrients, and TSS in wastewater.
- *Design/Operating Practices Achieving Zero Discharge*: EPA identified several design/operating practices that have been used at some plants to eliminate the discharge of FGD wastewater: 1) complete recycle, 2) evaporation impoundments, 3) conditioning dry fly ash, and 4) underground injection.
- *Other Technologies under Investigation*: EPA identified several other technologies that have been evaluated to treat FGD wastewater but for which full-scale operation has not been demonstrated, including zero-valent iron cementation, reverse osmosis, absorption media, ion exchange, and electrocoagulation. Other technologies under bench-scale study include polymeric chelates, taconite tailings, and nano-scale iron reagents.

Most plants that discharge FGD wastewater use surface impoundments for treatment; however, the use of more advanced wastewater treatment systems is increasing due to more stringent requirements imposed by some states and regions on a site-specific basis. Figure 7-1 shows the distribution of FGD wastewater management/treatment technologies based on the Steam Electric Survey and other industry-provided data for the 139 plants that reported using a wet FGD scrubber system in 2009 or planning to operate one by January 1, 2014.[40] Because the majority of the FGD wastewater management/treatment technologies are surface impoundments, chemical precipitation systems, biological treatment, or zero discharge, EPA grouped evaporation and constructed wetlands with the "Other" technologies for Figure 7-1. To identify the different treatment systems reported in the Steam Electric Survey, EPA grouped the systems into the following categories (shown in Figure 7-1):

- <u>Surface Impoundments</u>: Includes systems comprising one or more impoundments where the impoundment is the only treatment unit. This group also includes impoundments with chemical addition to control pH levels prior to discharge. It does not include systems containing impoundments as treatment units in a more advanced treatment system (*e.g.*, chemical precipitation, biological treatment), nor does it include systems that achieve zero discharge of FGD wastewater.
- <u>Chemical Precipitation</u>: Includes systems using hydroxide and/or organosulfide precipitation as the treatment mechanism. This group also includes systems using surface impoundments in combination with chemical precipitation systems and systems with chemical precipitation in combination with aerobic biological treatment for BOD_5 removal or biological treatment designed for nutrient removal (*i.e.*, not designed for heavy metals removal). It does not include systems with chemical precipitation and anoxic/anaerobic biological treatment systems, nor does it include systems that achieve zero discharge of FGD wastewater.

[40] EPA incorporated Steam Electric Survey reported planned systems operating prior to January 1, 2014, and company-verified steam electric generating unit retirements, fuel conversions, and wastewater treatment upgrades occurring no later than December 31, 2013 in EPA's analyses, compliance cost estimates, and pollutant loadings for the final Steam Electric Power Generating effluent limitations guidelines and standards (ELGs) (see Section 4.5).

- Biological Treatment: Includes systems using anoxic/anaerobic fixed-film or suspended growth biological treatment systems designed to remove selenium and other pollutants. This group includes systems that also include surface impoundments and/or chemical precipitation treatment units in combination with the biological system. It does not include systems that achieve zero discharge of FGD wastewater.
- Other: Includes systems using constructed wetlands or evaporation treatment units. This group includes systems that also include surface impoundments in combination with the constructed wetland/evaporation system and plants that operate tank-based settling systems that are not considered chemical precipitation (*e.g.*, clarifier systems). It does not include systems that achieve zero discharge of FGD wastewater.
- Zero Discharge: Includes all FGD wastewater treatment systems that achieve zero discharge, regardless of the type of unit (*e.g.*, surface impoundments, chemical precipitation) used to treat the wastewater prior to reuse.



Source: Steam Electric Survey [ERG, 2015a].

Note: This figure represents the EPA population used in analyses for the ELGs, which was developed using the Steam Electric Survey, industry profile changes (see Section 4.5), and additional industry-provided information.

Note: This figure represents the highest level of treatment; for instance, some plants categorized as "Other" or "Biological (Anoxic/Anaerobic)" may also operate a chemical precipitation system as part of a more advanced treatment system.

Figure 7-1. Distribution of FGD Wastewater Treatment/Management Systems Among 139 Plants Generating FGD Wastewater in the EPA Population

7.1.1 Surface Impoundments

Surface impoundments are designed to remove particulates from wastewater using gravity sedimentation. For this to occur, the wastewater must stay in the impoundment long enough for particles to fall out of suspension before being discharged from the impoundment. The size and configuration of surface impoundments varies by plant; some surface impoundments operate as a system of several impoundments, operated in series or in parallel, while others consist of one large impoundment. Plants typically size the impoundments to provide enough residence time to reduce TSS levels in the wastewater to a target concentration and to allow for a certain lifespan of the impoundment based on the expected rate of solids buildup within the impoundment. Coal-fired steam electric power plants do not typically add treatment chemicals to surface impoundments, other than to adjust the pH of the wastewater before it exits the impoundment to bring it into compliance with National Pollutant Discharge Elimination System (NPDES) permit limitations.

Surface impoundments can reduce the amount of TSS in the wastewater discharge provided there is sufficient residence time. In addition to TSS, surface impoundments can also reduce specific pollutants in the particulate form to varying degrees in the wastewater discharge. However, surface impoundments are not designed to reduce the amount of dissolved metals in the wastewater. The FGD wastewater entering a treatment system contains significant concentrations of several metals in the dissolved phase, including manganese, selenium, and boron, and these are mostly not removed by the FGD wastewater surface impoundments [ERG, 2008]. Additionally, the Electric Power Research Institute (EPRI) has reported that adding FGD wastewater to ash impoundments reduces the settling efficiency of the impoundment, leading to increased concentrations of TSS and other pollutants (*e.g.*, metals), due to gypsum particle dissolution occurring in the impoundment [EPRI, 2006]. EPRI has also reported that the FGD wastewater includes high loadings of volatile metals that can affect the solubility of metals in the ash impoundment, thereby potentially increasing the effluent metal concentrations [EPRI, 2006].

EPA compiled data for the 139 plants operating wet FGD systems, or planned wet FGD systems, and the wastewater treatment systems used to treat the FGD wastewaters generated. Based on these data, presented in Figure 7-1 surface impoundments are the most commonly used systems for managing FGD wastewater (approximately 28 percent). Most of these plants transfer the FGD wastewater directly to a surface impoundment that also treats other wastestreams, specifically fly and/or bottom ash transport water. According to the Steam Electric Survey, less than 16 percent of the 39 plants generating FGD wastewater managing it with surface impoundments transfer the FGD wastewater to a segregated surface impoundment specifically designated to treat FGD wastewater [ERG, 2015a]. Some of these plants discharge the FGD effluent from the segregated FGD surface impoundments directly to surface waters (with or without commingling with cooling water or other large volume wastestreams) while others transfer the effluent to another impoundment, potentially containing other combustion residuals (*i.e.*, ash), for further settling and dilution.

EPA has also identified plants that transfer the FGD wastewater to a surface impoundment for initial solids removal and then pump the wastewater to a chemical precipitation system or a biological treatment system for further treatment. As previously mentioned, because these surface impoundments are treatment units in a more advanced wastewater treatment system, EPA classifies these plants as “chemical precipitation” or “biological” rather than “surface impoundments.”

7.1.2 Chemical Precipitation

In a chemical precipitation wastewater treatment system, plants add chemicals to the wastewater to alter the physical state of dissolved and suspended solids to help settle and remove them. The specific chemical(s) used depends upon the type of pollutant requiring removal. EPA identified 39 steam electric power plants using some form of chemical precipitation as part of their FGD wastewater treatment system.[41] Power plants commonly use the following three types of systems to precipitate metals out of FGD wastewater:

- Hydroxide precipitation (37 plants).
- Iron coprecipitation (35 plants).
- Organoulfide precipitation (27 plants).

In a hydroxide precipitation system, plants add lime (calcium hydroxide) to elevate the pH of the wastewater to a designated set point, helping precipitate metals into insoluble metal hydroxides that can be removed by settling or filtration. Sodium hydroxide can also be used in this type of system, but it is more expensive than lime and, therefore, not as common in the industry.

Thirty-five power plants use iron coprecipitation to increase the removal of certain metals in a hydroxide precipitation system. Plants can add ferric (or ferrous) chloride to the precipitation system to coprecipitate additional metals and organic matter.[42] The ferric chloride also acts as a coagulant, forming a dense floc that enhances settling of the metals precipitate in downstream clarification stages.

Organosulfide precipitation systems use organosulfide chemicals (*e.g.*, trimercapto-s-triazine (TMT), Nalmet® 1689, sodium sulfide) to precipitate and remove heavy metals, similar to the set of metals removed in hydroxide precipitation. Plants operating organosulfide precipitation systems typically use TMT-15®, Nalmet® 1689, MetClear™, sodium sulfide, or other organosulfide chemicals in the system. The plants may test several different organosulfide chemicals to determine the one most appropriate for their treatment system. Based on discussions with system operators, EPA has determined that several plants switched from using TMT-15® when the treatment system started operation to using either Nalmet® 1689 or MetClear™ products. Plants made this switch from TMT-15® products because when they started working on optimizing the operation of the system, they performed studies with several different organosulfide chemicals, and the results exhibited significantly lower effluent mercury concentrations with Nalmet® 1689 or MetClear™ products [ERG, 2014a; ERG, 2015b]. Organosulfide precipitation can also provide more optimal removal of metals with lower solubilities, such as mercury, than hydroxide precipitation or hydroxide precipitation with iron

[41] The count of plant operating a chemical precipitation system does not equal the count in Figure 7-1 because this figure represents the highest level of treatment. There are plants categorized as "Other" or "Biological (Anoxic/Anaerobic)" that operate a chemical precipitation system in conjunction with a more advanced treatment system.

[42] The remainder of this section discusses the use of ferric chloride, as ferrous chloride is not commonly used in the steam electric power generating industry. However, ferrous chloride could also be used instead of ferric chloride and can also act as a reducing agent for wastewater with high ORP.

coprecipitation. The EPA sampling data suggest that adding organosulfide to the FGD wastewater can reduce dissolved mercury concentrations to less than 10 parts per trillion [ERG, 2012a]. Organosulfide precipitation is more effective than hydroxide precipitation in removing metals with low solubilities because metal sulfides have lower solubilities than metal hydroxides. Because organosulfide precipitation is more expensive than hydroxide precipitation, plants usually use hydroxide precipitation first to remove most of the metals, and then organosulfide precipitation to remove the remaining low solubility metals. This configuration overall requires less organosulfide, therefore reducing the expense for the bulk metals removal.

FGD wastewater chemical precipitation systems may include various stages of lime, organosulfide, and ferric chloride addition, as well as clarification stages. EPA identified that 24 plants add all three chemicals (*i.e.*, lime, ferric chloride, and organosulfide) within the chemical precipitation system. Some add all three chemicals to a single reaction tank, whereas other plants add the chemicals to separate tanks. The plants operating separate tanks may be targeting different pH set points within the system for optimal precipitation of certain metals. For example, We Energies' Pleasant Prairie Power Plant (Pleasant Prairie) adds hydrated lime to its FGD wastewater in the first reaction tank of the treatment system, raising the pH from 5.5 to 8.5 standard unit (S.U.) to precipitate soluble metals as insoluble hydroxides and oxyhydroxides. After primary clarification, the wastewater flows to a second reaction tank where organosulfide and hydrochloric acid is added, which drops the pH to around 7 S.U. Pleasant Prairie determined that adding the organosulfide at a neutral pH removed more mercury compared to operating at a more basic pH level [ERG, 2013a].

During its site visit program, EPA determined that the majority of steam electric power plant permits include only TSS, pH, and oil and grease (O&G) limitations for FGD wastewater based on the previously established best practicable control technology currently available (BPT) limitations for low volume wastewater. For this reason, 39 plants (28 percent) operate surface impoundments, as discussed previously, to remove TSS. However, some steam electric power plant permits include limitations for specific metals due to state or regional regulations or local limitations.[43] Most effluent limitations in NPDES permits for FGD wastewater (other than TSS and O&G) are water quality-based effluent limitations (WQBELs) designed to meet applicable water quality standards. In these cases, a number of plants have opted to install chemical precipitation systems designed and operated to target the specific metal or metals included in the permit. For example, if the plant has a mercury effluent limitation rather than only a TSS limitation, it is more likely to operate organosulfide precipitation, rather than just hydroxide precipitation or a surface impoundment.

One example of a treatment system operating to meet only the BPT-based limitations for TSS, pH, and O&G was AEP's Mountaineer plant, which initially operated a chemical precipitation system to treat its FGD wastewater. In 2008, 1 year after the start-up of the FGD scrubbers and the FGD wastewater treatment system, the plant went through a permit renewal process and the state proposed to add a WQBEL for mercury. Based on the proposed mercury limitations in the new permit, AEP conducted a pilot study evaluating three different

[43] In some cases, the steam electric power plant permit requires the plant to monitor and report the concentration of specific pollutants; however, the permit does not contain numerical effluent limitations that must be met prior to discharge.

technologies that could be installed as additional treatment downstream of the currently operating chemical precipitation system. Mountaineer conducted the pilot study from July through December 2008. During the first 3 months of the study, the mercury concentrations of the chemical precipitation system effluent feeding the pilot tests averaged 1,300 parts per trillion (ppt). None of the three technologies achieved the target effluent concentrations for the pilot testing. Therefore, AEP took steps to optimize the solids removal in the chemical precipitation system, including adding additional polymers and organosulfide. Using these optimization steps, AEP noted that "[t]he combination of supplemental coagulation and organosulfide addition consistently yielded approximately 80 percent of additional mercury reduction…" within the chemical precipitation system [AEP, 2010].

In some cases, plants may experience a spike in concentrations for certain metals in their untreated FGD wastewater, likely based on changes in fuels or operating conditions within the FGD scrubber. EPA's data demonstrate that well-operated systems maintain their chemical precipitation effluent concentrations because they actively monitor their wastewater for target concentrations of certain metals, allowing them to adjust the operation of the chemical precipitation system as necessary. Some plants actively monitor the influent to the treatment system and adjust chemical addition in an equalization tank with a 24-hour holding time as the first step in the treatment system. Plants can also monitor the effluent prior to discharge to make sure that they are in compliance before discharge. For example, Pleasant Prairie monitors the effluent from the system daily by collecting and analyzing samples using an in-house Method DMA 80 mercury analyzer, which can generate results in approximately 6 minutes [Michel, 2012]. The plant uses the mercury analyzer to alert operators when mercury concentrations are close to the plant's mercury permit limit; therefore, the operators can adjust the system (*e.g.*, chemical feed rates) to achieve additional mercury removal. When the concentrations are close to the permit limits, the plant begins transferring the wastewater in batches to the effluent storage tank. When the tank is full, the plant collects a sample of the wastewater to confirm it is below the permit limit. Once it confirms the concentration is lower than the limit, the plant discharges the wastewater from the effluent tank [ERG, 2013a].

Figure 7-2 presents a process flow diagram for a chemical precipitation system using hydroxide precipitation, organosulfide precipitation, and iron coprecipitation to treat FGD wastewater. A chemical precipitation system with no organosulfide precipitation stage would be similar, but without the organosulfide addition reaction tank.

For the system illustrated by Figure 7-2, the plant transfers the FGD wastewater from the plant's solids separation/dewatering process to an equalization tank. This tank equalizes the intermittent flows, allowing the plant to pump a constant flow of wastewater through the treatment system. The equalization tank also receives wastewater from a filtrate sump, which includes water from the gravity filter backwash and filter press filtrate.

The FGD wastewater is transferred in a continuous flow from the equalization tank to reaction tank 1, where the plant adds hydrated lime to raise the wastewater pH from between 5.5-6.0 S.U. to between 8.0-10.5 S.U. to precipitate the soluble metals as insoluble hydroxides and oxyhydroxides. The reaction tank also desaturates the remaining gypsum in the

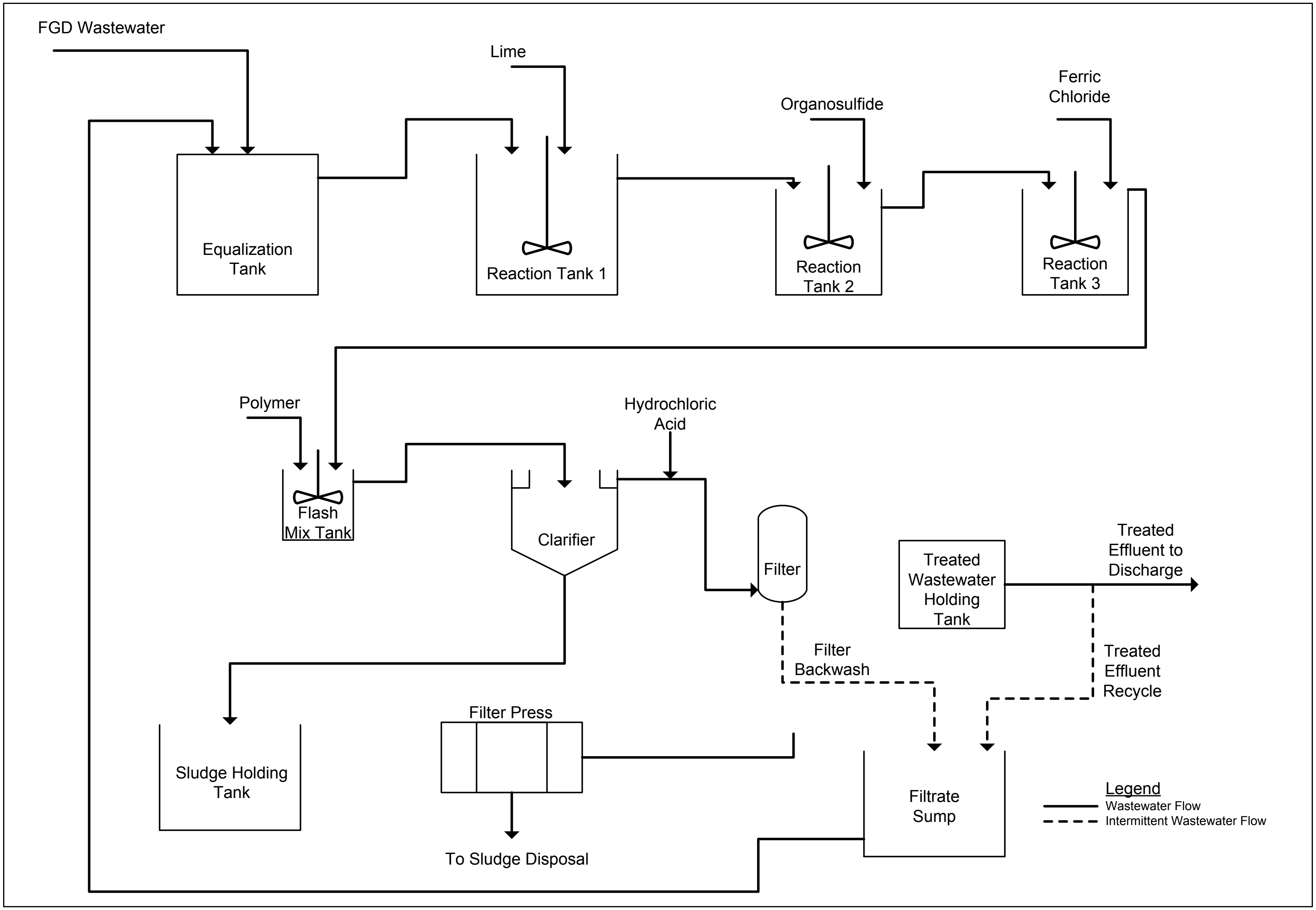


Figure 7-2. Process Flow Diagram for a Hydroxide and Organosulfide Chemical Precipitation System

wastewater, which prevents gypsum scale formation in the downstream wastewater treatment equipment.

From reaction tank 1, the wastewater flows to reaction tank 2, where the plant adds organosulfide. Plants can also reconfigure the treatment system by adding the organosulfide upstream of the hydroxide precipitation step or adding a clarification step between the two chemical addition steps.[44]

From reaction tank 2, the wastewater flows to reaction tank 3, where the plant adds ferric chloride to the wastewater for coagulation and coprecipitation. The effluent from reaction tank 3 flows to the flash mix tank, where the plant adds polymer to the wastewater prior to transferring it to the clarifier. Alternatively, the plant can add polymer directly to the wastestream as it enters the clarifier or reaction tank 3. The polymer acts to flocculate fine suspended particles in the wastewater.

The clarifier settles the solids that were initially present in the FGD wastewater as well as the additional solids (precipitate) formed during the chemical precipitation steps. The system may also include a sand filter to further reduce solids, as well as metals attached to the solids. The system transfers the backwash from the sand filters to a filtrate sump and recycles it back to the equalization tank at the beginning of the treatment system.

The plant collects the treated FGD wastewater in a holding tank and either discharges it directly to surface waters or, in most cases, commingles it with other wastestreams prior to discharge. The plant transfers the solids that settle in the clarifier (clarifier sludge) to the sludge holding tanks, after which the sludge is dewatered using a filter press. The plant then disposes of the dewatered sludge, or filter cake, in an on-site landfill, and transfers the filtrate from the filter press to a sump and recycles it back to the equalization tank at the beginning of the treatment system.

7.1.3 Biological Treatment

Biological wastewater treatment systems use microorganisms to consume biodegradable soluble organic contaminants and bind much of the less soluble fractions into floc. Pollutants may be reduced aerobically, anaerobically, and/or by using anoxic zones. Based on the information EPA collected during the rulemaking, steam electric power plants use two main types of biological treatment systems to treat FGD wastewater: aerobic systems to reduce biochemical oxygen demand (BOD_5) and anoxic/anaerobic systems to remove metals and nutrients. These systems may consist of fixed-film or suspended growth bioreactors, and operate as conventional flow-through or as sequencing batch reactors (SBRs). This section describes the wastewater treatment processes for each of these systems. These biological treatment processes are typically operated downstream of a chemical precipitation system or a solids removal system (*e.g.*, clarifier, surface impoundment). These pretreatment steps, specifically chemical

[44] Some plants may have a clarification step between reaction tank 1 and reaction tank 2 to remove the hydroxide precipitates from the wastewater prior to adding organosulfide. In addition, plants may adjust the pH prior to sulfide addition to optimize the removal of different metals.

precipitation systems, have been demonstrated to handle the FGD wastewater variability over long periods of time.

7.1.3.1 Aerobic Biological Treatment

Some steam electric power plants operate aerobic biological treatment systems to reduce BOD_5 in their FGD wastewater. In a conventional flow-through design, the system continuously feeds the wastewater to the aerated bioreactor. The plant may add chemicals to the wastewater before it enters the bioreactor to adjust the pH levels and, in certain climates, feed the wastewater through a heat exchanger to maintain a certain temperature to ensure the microorganisms are operating at optimal levels [ERG, 2007]. The microorganisms in the reactor use the dissolved oxygen from the aeration to digest the organic matter in the wastewater, thus reducing the BOD_5. The digestion of the organic matter produces sludge, which the plant may dewater with a vacuum filter to better manage its ultimate disposal. The treated wastewater from the system overflows out of the reactor.

An SBR is an activated sludge treatment system that can reduce BOD_5 and, when operated to create anoxic zones under certain conditions, can also reduce nitrogen compounds through nitrification and denitrification. Plants often operate at least two identical reactors sequentially in batch mode. The treatment in each SBR consists of a four-stage process: filling, aeration and reaction, settling, and decanting. While one of the SBRs is settling and decanting, the other SBR is filling, aerating, and reacting.

As an aerobic system, the SBR operates as follows. In the filling stage, the FGD wastewater is transferred into a reactor that contains some activated sludge from the previous reaction batch. During the aeration and reaction stages, the reactor is aerated and the microorganisms reduce the BOD_5 by digesting the organic matter in the wastewater. During the settling phase, the plant stops aeration and the solids in the SBR settle to the bottom. The plant then decants the wastewater off the top of the SBR and transfers it to surface water for discharge or to additional treatment or reuses it in plant processes without further treatment. Additionally, the plant removes and dewaters some of the solids from the bottom of the SBR, but retains some of the solids in the SBR to keep microorganisms in the system.

7.1.3.2 Anoxic/Anaerobic Biological Treatment

Some coal-fired power plants use anoxic/anaerobic biological systems to reduce the concentrations of certain pollutants (*e.g.*, selenium, mercury, nitrates) more effectively than has been possible with surface impoundments, chemical precipitation, or aerobic biological treatment processes. Figure 7-3 presents a process flow diagram for an anoxic/anaerobic biological treatment system. The microorganisms in this system are susceptible to temperatures in excess of 105ºF [Pickett, 2005]. Because of this susceptibility, some plants cool the FGD wastewater before it enters the biological system using heat exchangers or cooling impoundments. Based on data from EPA sampling episodes, these plants generally are located in geographic regions with sustained periods of maximum ambient temperatures greater than 90ºF [U.S. EPA, 2015].

Four plants use an anoxic/anaerobic fixed-film bioreactor that consists of an activated carbon bed, such as granular activated carbon (GAC) or some other permanent porous substrate, that is inoculated with naturally occurring, beneficial microorganisms that reduce selenium and other metals [Sonstegard, 2010].[45] The microorganisms grow within the activated carbon bed, creating a fixed film that retains the microorganisms and precipitated solids within the bioreactor. The system uses microorganisms chosen specifically for use in FGD systems because of their hardiness in the extreme water chemistry as well as selenium respiration and reduction [Sonstegard, 2010]. Steam electric power plants also add a molasses-based feed source for the microorganisms to the wastewater before it enters the bioreactor [ERG, 2012b].

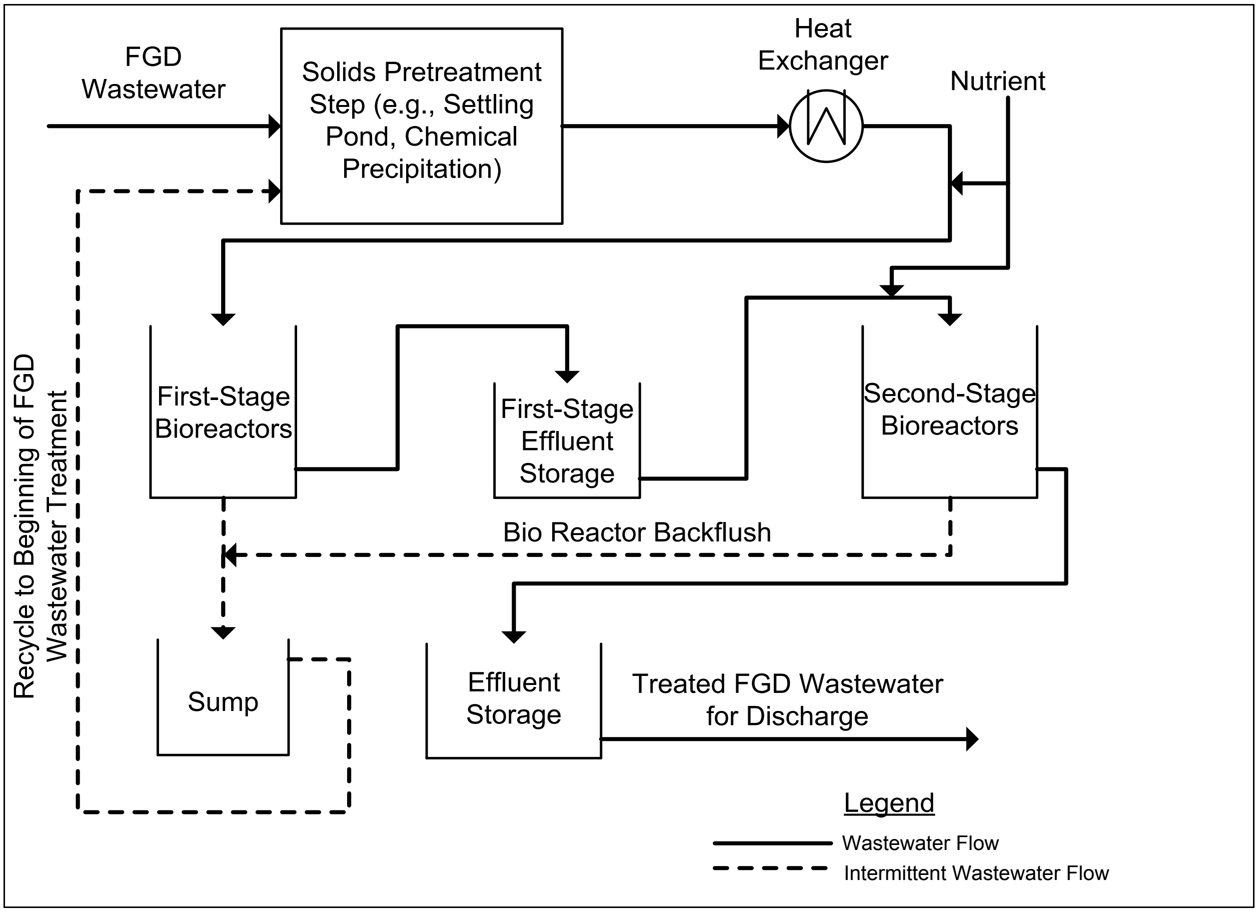


Figure 7-3. Process Flow Diagram for an Anoxic/Anaerobic Biological Treatment System

The bioreactor is designed for plug flow to ensure the feed water is evenly distributed and has maximum contact with the microorganisms in the fixed film. The bioreactor contains different zones that have differing oxidation-reduction potentials (ORP). Plants operate the bioreactors to achieve a negative ORP in the reactor effluent, which provides the optimal environment to reduce selenium to its elemental form. The ORP is controlled by the amount of nutrient that is fed to the system [ERG, 2012b]. The top part of the bioreactor, where the plant feeds the wastewater, is aerobic with a positive ORP, which allows nitrification and organic

[45] One additional plant currently operates an anoxic/anaerobic fixed-film bioreactor and is planned to install an evaporation system; therefore, it is considered "Other" in Figure 7-1 and are not included in this count of four plants.

carbon oxidation to occur. As the wastewater moves down through the bioreactor, it enters an anoxic zone (negative ORP) where denitrification and chemical reduction of selenium (both selenate and selenite) occur [Pickett, 2006; Sonstegard, 2010]. The system maintains a pH level in the bioreactor between 6.0 and 9.0 S.U. because extreme high or low pH levels could affect the performance of the microbes and potentially allow undesirable microbes to propagate [ERG, 2012b].

When the microorganisms reduce the selenate and selenite to elemental selenium, it forms nanospheres that adhere to the cell walls of the microorganisms. Because the activated carbon bed retains the microorganisms within the bioreactor, the elemental selenium is essentially fixed to the activated carbon until it is removed from the system. The microorganisms can also reduce other metals, including arsenic, cadmium, nickel, and mercury, by forming metal sulfides within the system [Pickett, 2006].

The bioreactor system typically contains multiple bioreactor cells. For example, the Duke Energy Carolinas' Allen Steam Station and Belews Creek Steam Station have two stages of bioreactor cells in series, as shown in Figure 7-3, but both stages of bioreactors contain multiple cells in parallel. Plants usually employ multiple bioreactors to provide the necessary residence time to achieve the specified removals.

Periodically, the bioreactor is backflushed to remove the solids and inorganic materials that have accumulated within it. The flushing process involves flowing water upward through the system, which dislodges the particles fixed within the activated carbon. The water and solids overflow out of the top of the bioreactor and are removed from the system. This flush water contains elevated levels of solids, with selenium adhered to the solids [Pickett, 2006] and would likely need to be treated prior to discharge. Some plants send the backflush water to the beginning of the chemical precipitation wastewater treatment system so that the system can remove the solids (and adhered selenium) within the clarifier. Other plants transfer the backflush water to a surface impoundment where the solids (and adhered selenium) settle out [ERG, 2010; Jordan, 2008].

As the microorganisms denitrify the wastewater, nitrogen and carbon dioxide gases form, which periodically build up and form pockets within the bioreactor. As a result, water flows through channels, reducing microbial contact and increasing head-loss across the bioreactor, an overall negative effect on the system [Sonstegard, 2010]. To remove these gas pockets, plants occasionally perform a degassing operation by transferring water backwards through the cells, similar to a backflush, but the flush is only long enough for the gas to "burp" out of the system [ERG, 2012b]. The system flush is long enough to lift the biomatrix and release entrained gases, but short enough to avoid flushing any water out of the bioreactor [Sonstegard, 2010].

One plant operates another type of anoxic/anaerobic biological treatment system that consists of suspended growth flow-through bioreactors instead of fixed-film bioreactors. Both designs share the fundamental processes that lead to nitrification/denitrification and reduction of metals in anoxic and anaerobic environments. The plant began operating the anoxic/anaerobic suspended growth biological treatment system in January 2012 [ERG, 2013b].

Plants can also operate SBRs to achieve anoxic/anaerobic conditions. The SBR operation is similar to the aerobic biological treatment system described above; however, the aeration stage is followed by periods of air on, air off, which creates aerobic zones for nitrification and anoxic zones for denitrification to remove the nitrogen in the wastewater. According to the treatment system vendor, SBR systems will denitrify the wastewaters, but the ORP in systems currently in operation at steam electric power plants is not managed at levels conducive to reducing metals. Therefore, these SBR systems, as currently designed and operated, do not remove selenium (and other metals) as effectively as the fixed-film or suspended growth bioreactor systems.

Management of the ORP in the bioreactor is important for optimizing removal of nitrate-nitrite and selenium, regardless of whether the system uses a fixed-film, suspended growth, or other design. Nitrate-nitrite and selenium removals are optimized when ORP in the reactor is in range of -300 to -150 mV [Teng et. al., 2012; Lau et. al., 2012]. Additionally, conditions of very high, positive ORP (on the order of 500 mV) have been associated with the presence of high concentrations of oxidants in the FGD wastewater [Brown et. al., 2013]. High concentrations of oxidants have the potential to inhibit the growth and activity of the anaerobic microorganisms that reduce the nitrate-nitrite and selenium However, testing of the biological treatment systems at the pilot-scale and at full-scale systems operating at steam electric power plants has demonstrated that the presence of oxidants can be overcome with an applied understanding of oxidant/FGD chemistry, awareness that adjustments to certain upstream processes can affect ORP, and implementation of an oxidant monitoring and mitigation strategy. In doing so, plant operators can (1) take steps to prevent or mitigate the formation of oxidants in the FGD absorber; (2) monitor ORP and total oxidants in the absorber and in the purge directed to the wastewater treatment system; (3) employ oxidant removal and control, as needed, by adding reducing agents within the chemical precipitation stage of the treatment system or a separate unit process upstream of the bioreactor; and (4) monitor and maintain the ORP within the bioreactor at the appropriate level.

A pilot test conducted at a plant in the southeast U.S. highlights the importance of controlling ORP. At this site, FGD wastewater from a surface impoundment was sent to a pilot-scale fixed-film anoxic/anaerobic bioreactor, as well as several other pilot-scale treatment technologies. Pollutant removal performance for this pilot test was degraded due to the very low pH and high ORP of the wastewater. The test also suffered from the small-scale pilot equipment being not sufficiently protected against exposure to cold weather, which resulted in freezing causing issues with chemical dosing equipment. During the test period, plant operators determined that the pH control loop for the FGD absorber was not operating properly; this, in turn, ultimately affected the wastewater pH and FGD purge rate and led to elevated levels of oxidants in the wastewater. Subsequent laboratory testing of the FGD wastewater from the surface impoundment showed that by adding reducing agents, the oxidants could be removed and the wastewater was able to support microbial growth and activity. Since that time, the vendor has continued to perform pilot testing at other plants and found that by monitoring the ORP in the wastewater, optimizing pretreatment with chemical precipitation including the addition of reducing agents to pretreat the wastewater, the issues related to the increased ORP levels can be controlled and the biological treatment system is able to function as expected [ERG, 2015c]. A plant operating a full-scale biological treatment system similarly found that adding reducing agents to the wastewater prior to sending it to the bioreactor, in this case using ferrous chloride instead of ferric chloride in the chemical precipitation stage, effectively controlled the oxidants.

7.1.4 Evaporation System

Mechanical evaporators in combination with a final drying process can significantly reduce the quantity of wastewater pollutants and volume discharged from certain process operations at various types of industrial plants, including steam electric power plants, oil refineries, and chemical plants. One type of evaporation system uses a falling-film evaporator (also referred to as a brine concentrator) to produce a concentrated wastewater stream (*i.e.*, brine) and a reusable distillate stream. The concentrated wastewater stream is then processed in a forced-circulation crystallizer, in which the remaining water is evaporated. In this configuration, the evaporation system generates a distillate stream and a solid by-product that can then be disposed of in a landfill.

Steam electric power plants most often use evaporation systems to treat wastestreams such as cooling tower blowdown and demineralizer waste. In 2009, however, one plant in the United States began to operate an evaporation system to treat FGD wastewater [ERG, 2015a] and two other U.S. plants have installed, or are in the process of installing, this technology [Jacobs Consultancy, 2012; Loewenberg, 2012]. Additionally, four coal-fired power plants in Italy are treating FGD wastewater with evaporation systems [Rao, 2008; Veolia Water Solution, 2007]. Two other plants in Italy also installed evaporation systems but subsequently determined that off-site disposal was more economical.

Before entering the evaporation system, FGD wastewater is usually pretreated to remove calcium and magnesium salts, as shown in Figure 7-4. Calcium and magnesium salts in the FGD wastewater can pose difficulties for the forced-circulation crystallizer. To prevent this, plants can pretreat the FGD wastewater using chemical precipitation and a lime-softening process upstream of the brine concentrator. With water softening, the magnesium and calcium ions precipitate out of the wastewater and are replaced with sodium ions, producing an aqueous solution of sodium chloride that can be more effectively treated with a forced-circulation crystallizer [Shaw, 2008]. See Section 7.1.2 for more specific information on chemical precipitation systems.

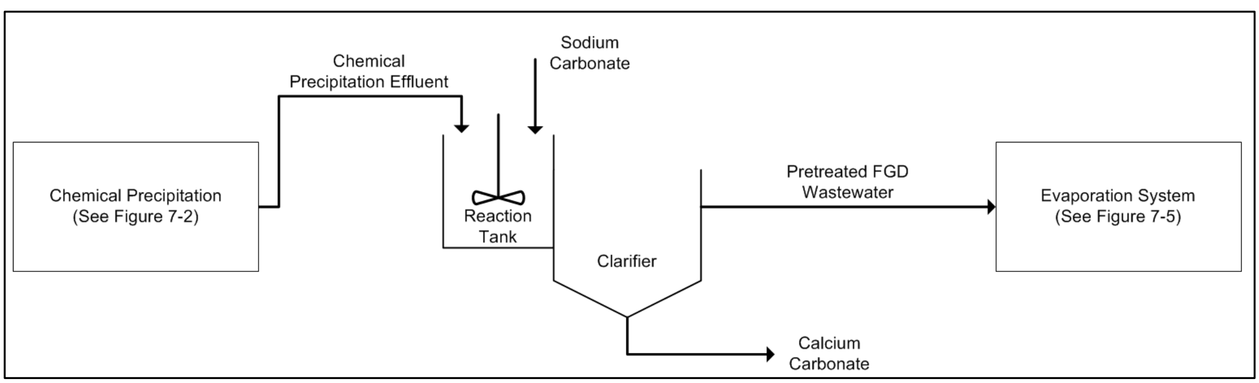


Figure 7-4. Chemical Precipitation and Softening Pretreatment for FGD Wastewater Prior to Evaporation

Figure 7-5 presents a process flow diagram for an evaporation system. When an evaporation system is used to treat FGD wastewater, the first step is to adjust the pH of the FGD wastewater to approximately 6.5 S.U. Some plants also add an antiscalant to the wastewater prior to the evaporation system [ERG, 2012c]. Following pH adjustment, the FGD wastewater goes through a heat exchanger to bring the wastestream to its boiling point. From the heat exchanger, the wastestream is sent to the deaerator, where the noncondensable materials such as carbon dioxide and oxygen are vented to the atmosphere [ERG, 2012c].

From the deaerator, the wastestream enters the sump of the brine concentrator. Brine from the sump is pumped to the top of the brine concentrator and enters the heat transfer tubes. While falling down the heat transfer tubes, part of the solution is vaporized and then compressed and comes in contact with the shell side of the brine concentrator (*i.e.*, the outside of the tubes). With the temperature difference between the compressed vapor and the brine solution, the compressed vapor transfers heat to the brine solution, which flashes to a vapor, and the compressed vapor cools and condenses as distilled water [ERG, 2012c].

The condensed vapor (*i.e.*, distillate water) can be recycled back to the FGD process, used in other plant operations (*e.g.*, boiler makeup water), or discharged. If the plant uses the distillate for other plant operations that generate a discharge stream (*e.g.*, used as boiler make-up and ultimately discharged as boiler blowdown), then the FGD process/wastewater treatment system is not truly zero discharge. Therefore, operating an evaporation system does not guarantee that the FGD process/wastewater treatment system achieves zero discharge.

The concentrated brine slurry from the brine concentrator tubes falls into the sump and is recycled with the feed (FGD wastewater) to the top of the brine concentrator. Typically, the plant continuously withdraws a small amount from the sump and transfers it to a final drying process. To prevent scaling within the brine concentrator because of the gypsum in the FGD wastewater, the brine concentrator is seeded with calcium sulfate. The calcium salts preferentially precipitate onto the seed crystals instead of the tube surfaces of the brine concentrator. If the treatment system is preceded by chemical precipitation and softening, the brine concentrator can typically concentrate the FGD scrubber purge five to 10 times, which reduces the inlet FGD scrubber purge water volume by 80 to 90 percent [Shaw, 2008]. However, without pretreatment, the brine concentrator is not as effective because of boiling point rise (the increase in energy required to

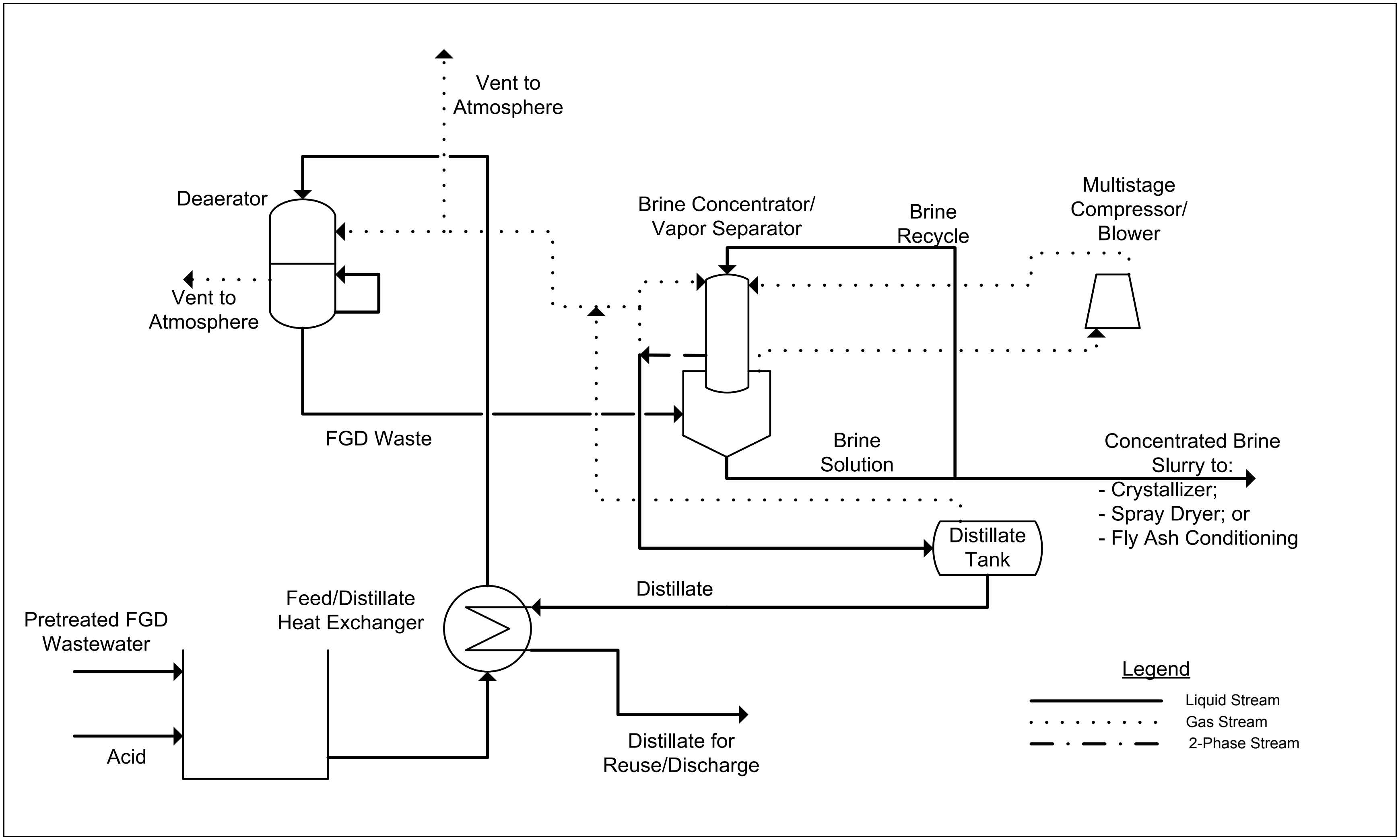


Figure 7-5. Process Flow Diagram for an Evaporation System

concentrate the wastewater stream due to the additional calcium and magnesium salts or other solids in the wastewater). For example, one plant operates only a clarifier prior to the evaporation system. The brine concentrator reduces the inlet FGD scrubber purge water volume only up to 53 percent [ERG, 2012d].

As described previously, the configuration of the evaporation system that EPA evaluated as the basis for the technology option consisted of a pretreatment system including hydroxide and organosulfide chemical precipitation, softening, the evaporation system (brine concentrator), and a forced-circulation crystallizer. However, there are other options that plants can consider for processing the concentrated brine stream from the evaporation system. Plants typically consider hree other options for eliminating the brine concentrate: (1) using the brine to condition (add moisture to) dry fly ash or other solids and disposing of the mixture in a landfill (approach used at Kansas City Power & Light's Iatan Generating Station); (2) adding reagents to fixate the material in a pozzolanic reaction and disposing of the mixture in a landfill; or (3) evaporating the brine in a spray dryer.

Plants can use brine concentrators to treat a wastestream other than FGD wastewater (*e.g.*, cooling tower blowdown). For these non-FGD systems, the plant typically sends the concentrated brine from the sump to a forced-circulation crystallizer to evaporate the remaining water from the concentrate and generate a solid product for disposal.

Coal-fired steam electric power plants can avoid having to operate the chemical precipitation pretreatment process by using a spray dryer to evaporate the residual wastestream from the brine concentrator. Because the material generated from this process is hygroscopic (*i.e.*, readily taking up and retaining moisture), the solid residual from the spray dryer is typically bagged immediately and disposed of in a landfill. Alternatively, the plant can combine the concentrated brine wastestream with dry fly ash or other solids for disposal in a landfill. To do this, the plant must generate enough dry fly ash to mix with the brine; otherwise, there will be brine remaining that the plant must handle.

At least one vendor of the evaporation system for treating FGD wastewater has been pilot-testing a process to solidify the concentrated brine from the evaporation system. The solidification process consists of mixing the concentrated brine with fly ash and other reagents to form a solidified material via a pozzolanic reaction. The vendor's pilot testing has shown that the solidified material passes all the toxicity characteristic leachating procedure criteria. According to the vendor, by solidifying the material, it is not necessary to soften the wastewater prior to the evaporation system, which significantly reduces the operation and maintenance (O&M) costs and the amount of solids generated by the system. It also reduces the capital costs because the solidification process equipment is significantly less expensive than a forced-circulation crystallizer [ERG, 2015d].

Similarly, another vendor of the evaporation system for treating FGD wastewater has developed a system that does not require a chemical precipitation or lime-softening step. Therefore, the FGD wastewater can be sent directly into the evaporation and crystallization process that is operated at a low temperature for optimizing the FGD wastewater chemistry. At a lower temperature, dissolved solids will crystallize (*e.g.*, hydrates and double salts) at lower concentrations. Therefore, this system does not produce any additional sludge from chemical additions, allows the evaporated water to be reused, and produces stable solids for disposal [Veolia Water Solution, 2013; ERG, 2015d].

7.1.5 Constructed Wetlands

A constructed wetland treatment system is an engineered system that uses natural biological processes involving wetland vegetation, soils, and microbial activity to reduce the concentrations of metals, nutrients, and TSS in wastewater. A constructed wetland typically consists of several cells that contain bacteria and vegetation (*e.g.*, bulrush, cattails, peat moss), which the steam electric power plant selects based on the specific pollutants targeted for removal. The vegetation completely fills each cell and produces organic matter (*i.e.*, carbon) used by the bacteria. In the aqueous phase of the wastewater, the bacteria reduce metals, such as mercury and selenium, to their elemental state. The metals removed by the bacteria will partition into the sediment, where they either accumulate or are absorbed by the vegetation in the wetland cells [EPRI, 2006; Rogers, 2005].

High temperature, chemical oxygen demand (COD), nitrates, sulfates, boron, and chlorides in the wastewater can adversely affect constructed wetlands' performance. To avoid this, plants typically dilute the FGD wastewater with service water before it enters the wetland to reduce the temperature of the wastewater and concentration of chlorides and other pollutants such as boron, which can harm the vegetation in the treatment cells. For example, most plants typically maintain the chlorides in a constructed wetland treatment system below 4,000 milligrams per liter (mg/L) but operate their FGD scrubber systems to maintain chloride levels within a range of 10,000-20,000 parts per million (ppm); therefore, they would need to dilute the FGD wastewater prior to transferring it to a wetland system. EPA identified three plants operating constructed wetlands to treat FGD wastewater. EPA has observed that these steam electric power plants tend to operate their FGD systems at lower concentrations of chlorides (*e.g.*, 1,000 to 10,000 ppm). To do this, the plants purge FGD wastewater from the system at a higher flow rate than they otherwise if operating the FGD system at a higher chloride concentration level.

7.1.6 Design/Operating Practices Achieving Zero Discharge

During the site visit program, EPA observed that some of the plants operating wet FGD systems managed the system to eliminate the discharge of FGD wastewater. EPA identified 51 plants (37 percent) achieving zero discharge of FGD wastewater. Based on information collected as part of the Steam Electric Survey, EPA identified five operating practices available to prevent the FGD wastewater discharge:

- Complete recycle.
- Evaporation impoundments.
- Underground injection.
- Operation of both wet and dry FGD scrubber systems.
- Dry fly ash conditioning.

This section discusses each of these practices.

Complete Recycle

Most plants do not recycle their treated FGD wastewater within the FGD system because of the elevated chloride levels in the treated effluent. Some plants, however, completely recycle the FGD wastewater within the system without using a wastewater purge stream to remove chlorides. Such plants generally do not produce a saleable solid product from the FGD system (*e.g.*, wallboard-grade gypsum). Because the plant is not selling the FGD solid by-product and is most likely disposing of it in a landfill, it has no specific chloride specifications for the FGD solids material and does not need a separate wastewater purge stream. Transferring the FGD solids to the landfill essentially serves as the chloride purge from the system.

From the information provided in the Steam Electric Survey, EPA determined that, of the 139 plants operating wet FGD systems, 18 operate complete-recycle systems and do not discharge any FGD wastewaters to surface waters. Of these 18 plants, nine operate natural or inhibited oxidation system, which generate calcium sulfite instead of calcium sulfate, and are therefore more likely to dispose of the solids in a landfill.

Evaporation Impoundments

EPA identified nine plants located in the southwestern United States that use evaporation impoundments to avoid discharging any FGD wastewater to surface waters. Because of the warm, dry climate in this region, the plants can transfer the FGD wastewater to one or more impoundments where the water evaporates. The evaporation rate from the impoundments at these plants is greater than or equal to the flow rate of the FGD wastewater and amount of direct precipitation entering the impoundments; therefore, there is no discharge to surface water.

Conditioning Dry Fly Ash

Many plants that operate dry fly ash handling systems need to add water to the fly ash to suppress dust or improve handling and/or compaction characteristics in an on-site landfill. Although conditioning fly ash involves water in direct contact with dry fly ash, this is not considered fly ash transport water because the purpose is not to convey fly ash from the collection/storage equipment or boiler. EPA identified five plants that use FGD wastewater to suppress dust around landfills or to moisture condition fly ash prior to landfill disposal [ERG, 2015a]. Another plant, discussed in Section 7.1.4, uses an evaporation system to reduce the volume of FGD wastewater and then mixes the concentrated brine slurry with dry fly ash and disposes of it in a landfill to prevent discharging FGD wastewater [ERG, 2013c].

Combination of Wet and Dry FGD Systems

Operating combined wet and dry FGD systems on the same unit or at the same plant can eliminate the scrubber purge associated with the wet FGD process. The dry FGD process involves atomizing and injecting wet lime slurry, which ranges from approximately 18 to 25 percent solids, into a spray dryer. The water contained in the slurry evaporates from the heat of the flue gas within the system, leaving a dry residue that is removed from the flue gas by a fabric filter (*i.e.*, baghouse) [Babcock and Wilcox, 2005]. By operating a combination system, the plant can use the FGD wastewater associated with the wet FGD system as makeup water for the lime slurry feed to the dry FGD process, thereby eliminating the FGD wastewater [McGinnis, 2009].

From its data collection activities, EPA identified three plants that planned to operate dry and wet FGD systems in combination on existing or planned units, eliminating the need to discharge the wastewater associated with the wet FGD system [ERG, 2015a].

Underground Injection

Underground injection is used to dispose of wastes by injecting them into an underground well as an alternative to discharging wastewater to surface waters. Based on EPA's information, one plant began using underground injection to dispose of FGD wastewater in 2007, but it has not been successful. Because of unexpected pressure issues and problems with building the wells due to geological formations encountered (unrelated to the characteristics of the FGD wastewater), the plant has not been able to continuously inject the wastewater. The plant operates a chemical precipitation system as pretreatment for the injection system.[46] When it is not injecting the FGD wastewater, the plant transfers the effluent from the chemical precipitation system to the cooling lake, which does not discharge to surface water (*e.g.*, zero discharge) [ERG, 2013d; ERG, 2015a]. Another plant began injecting the FGD wastewater underground in 2010 [ERG, 2015a]. Underground injection is currently managed under the Underground Injection Control (UIC) program. Underground disposal of FGD wastewater constitutes zero discharge to waters of the United States.

7.1.7 Other Technologies under Investigation

In addition to chemical precipitation, biological treatment, evaporation, constructed wetlands, and zero discharge systems for FGD wastewater treatment, EPA also identified several emerging treatment technologies that have been proven to treat FGD wastewater. EPA reviewed EPRI reports, industry sources, and published research articles describing alternative FGD wastewater treatment technologies being evaluated at the bench-, pilot-, and full-scale levels. For additional information on these and other technologies under investigation for FGD wastewater treatment, see "Evaluation of Emerging Technologies for the Treatment of Flue Gas Desulfurization Wastewater" [ERG, 2015d].

Iron and Sulfide Additives with Microfiltration

EPRI conducted bench- and pilot-scale testing of a process to help remove mercury from FGD wastewater. This process involved iron coprecipitation (*e.g.*, ferric chloride addition) and organosulfide addition (common in currently operating chemical precipitation systems), but added microfiltration to determine if that would improve solids removal over conventional clarification and media filtration. Microfiltration typically targets removing particles between 0.1 and 2 microns in size. Incorporating sludge recirculation theoretically increases particle size of the resulting precipitates, resulting in better solids removal in conjunction with microfiltration. EPRI determined that adding microfiltration may help remove fine-particle mercury that passes through media filters [EPRI, 2009a].

[46] Plant operates an iron coprecipitation system.

Zero-Valent Iron Cementation

In general, zero-valent iron (ZVI) cementation removes pollutants by contacting wastewater with an iron powder, reducing the pollutant to its elemental form (*i.e.*, cementation). The pH of the wastewater is increased to form metal hydroxides, and the wastewater is filtered to remove the precipitated solids. Next, the iron powder is separated from the wastewater and recycled back to the cementation step. ZVI cementation has been proven to remove several heavy metals from FGD wastewater (*e.g.*, arsenic, mercury, copper, chromium); however, EPRI's research was focused on removing selenium in the selenate, selenite, and other forms.

EPRI conducted bench-scale testing of the ZVI cementation treatment technology as a way to remove all species of selenium from FGD wastewater. EPRI believes this process may also effectively remove mercury. From the initial studies, EPRI concluded that the ZVI iron cementation approach is promising for treating FGD wastewater for multiple species of selenium, including selenite, selenate, and other unknown selenium compounds [EPRI, 2008a].

EPRI continued its study of ZVI cementation by specifically designing a pilot-scale system to remove selenium and installing the prototype at a plant burning coal from the Powder River Basin with FGD wastewater containing high levels of total dissolved solids (TDS), sulfate, magnesium, nitrate/nitrite-nitrogen, and selenium. Additionally, EPRI evaluated the effectiveness of the pilot-scale treatment system under continuous flow conditions. The study showed that ZVI cementation does reduce selenium, specifically at a lower pH and a greater hydraulic retention time. EPRI stated that increasing the hydraulic retention time improves the dissolution of the metallic selenium ion. The study results also show that selenium removal and iron dissolution are directly related; however, the pilot-scale system was unable to duplicate the selenium removal levels observed in the bench-scale testing described above. Under ideal operating conditions, the bench-scale testing showed that iron cementation reduced dissolved selenium to less than 0.05 mg/L; however, the pilot-scale testing's lowest selenium effluent concentration was 0.159 mg/L. EPRI also evaluated mercury removals from a limited data set. EPRI found that mercury was significantly reduced (by a range of 84 to 97 percent) in the iron reactor [EPRI, 2009b].

EPA obtained information from two pilot studies conducted as a partnership between EPRI and SCANA at a coal-fired power plant that evaluated a ZVI technology for treating FGD wastewater. The pilot studies were performed from November 2013 to March 2014 and tested two different system configurations using the same ZVI technology. The pilot test used FGD surface impoundment effluent as the initial influent stream to the system; however, on February 28, 2014, a pilot-scale chemical precipitation system was added upstream of the pilot technologies to pretreat the FGD wastewater. The first ZVI system configuration (System 1) utilized a 1.0 gallon per minute (gpm) FGD wastewater influent flow rate and treated the wastewater using the following design elements:

- One sand filter.
- Three bag filters (25 micrometers (µm), 10µm, and 1µm).
- Eight vessels (125 gallons) containing stacks of porous media loaded with fine ZVI shavings.

This pilot test was not able to achieve effluent pollutant that met ELG limitations for selenium, mercury, arsenic, and nitrate/nitrite as N. However, after chemical precipitation was installed upstream of the pilot test, this system configuration consistently maintained selenium concentrations less than 100 ppb in the effluent, compared to an effluent selenium concentration of 1,200 to 1,400 ppb when the FGD surface impoundment effluent was used as the influent. The second ZVI system configuration (System 2) maintained an influent flow rate of 0.00132 gpm and treated the FGD wastewater using the following design elements:

- One anaerobic membrane bioreactor (continuous stirred tank reactor, followed by an ultrafilter membrane).
- An ultraviolet (UV) disinfection step.
- Four columns (2.5” diameter; 12.5” media) containing porous media loading with fine ZVI shavings.

The bioreactor was added before the ZVI columns to remove the nitrates because the positive charge on the nitrogen causes these species to compete with the selenium species and significantly inhibit selenium removal from the FGD wastewater. Therefore, the second ZVI system configuration, containing the pretreatment bioreactor, was able to meet the ELG limitations for selenium, mercury, nitrate/nitrite as N, and arsenic. In addition, the ZVI media chemically reduced and removed other selenium compounds, such as selenocyanate and methyl seleninic acid [EPRI, 2014; ERG, 2015e].

EPA also obtained information from a ZVI pilot study conducted at another coal-fired power plant. The plant conducted this pilot study from March 2014 to July 2014 using the effluent from its chemical precipitation system. This ZVI system (System 3) contained a sand filter, bag filters, and eight vessels containing porous ZVI-loaded media (similar to System 1 described above). However, the chemical precipitation effluent from this plant contained lower levels of nitrates than the other coal-fired power plant (where System 1 and 2 were studied). The pilot study demonstrated that this ZVI system met the ELG limitations for selenium, arsenic, and mercury [ERG, 2015e; ERG, 2015f].

<u>Reverse Osmosis</u>

Reverse osmosis systems are currently in use at steam electric power plants, usually to treat boiler makeup water or cooling tower blowdown wastewaters. EPRI identified a high-efficiency reverse osmosis (HERO™) process that operates at a high pH, allowing the system to treat wastewaters with high silica concentrations without scaling or membrane fouling because silica is more soluble at a higher pH. The wastewater undergoes a water-softening process to raise its pH before entering the HERO™ system.

Although the HERO™ system is currently in use in the steam electric power generating industry to treat cooling tower blowdown wastewater, its use for FGD wastewater is potentially limited due to the osmotic pressure of the FGD wastewater due to high concentrations of chlorides and TDS [EPRI, 2007]. Although many plants may not be able to use the HERO™ system to treat FGD wastewater, some plants with lower TDS and chloride concentrations may be able to. The HERO™ system is of particular interest for treating boron in FGD wastewaters because boron becomes ionized at an elevated pH and, therefore, could be removed using a reverse osmosis system [EPRI, 2007].

Sorption Media

The drinking water industry uses sorption media to remove arsenic from the drinking water. Because of the sorption media's success at removing similar pollutants found in FGD wastewater, specifically arsenic, EPRI reviewed sorption media technologies to determine whether they are applicable for treating FGD wastewater. These sorption processes adsorb pollutants onto the media's surface area using physical and chemical reactions. EPRI determined the most effective adsorbents are metal-based single-use products, which can be disposed of in nonhazardous landfills. EPRI also determined granular ferric oxide or hydroxide- and titanium-based oxides were the most prevalent adsorbent at the time of the study. Ferric- and titanium-based media effectively remove both common forms of arsenic (arsenate and arsenite) and selenium (selenite) over a wide pH range [EPRI, 2007].

A University of Granada study analyzed the absorption of bromide and iodide using a type of sorption media, metal-doped aerogels, which attaches the halide on the aerogel surface through a chemisorption process. This technique used Ag-doped aerogels in 25 cubic centimeters (cm^3) columns to remove bromide from Lake Zurich and mineral water. The columns were saturated with bromide and iodide and regenerated with NH_4OH. The study exhibited a high efficiency of removing the bromide from the water before and after regeneration; however, additional studies need to be performed to analyze whether this sorption media would be effective for bromide removal in FGD wastewater [Sanchez-Polo, 2007].

EPA identified one plant that installed an FGD wastewater treatment system that includes chemical precipitation followed by another treatment stage that uses cartridge filters in combination with two sets of adsorbent media specifically designed to help remove metals. After passing through three sets of cartridge filters (3-micron, 1-micron, and then 0.2 micron), the FGD wastewater passes through a carbon-based media that adsorbs mercury and then through a ferric hydroxide-based media that adsorbs arsenic, chromium, and other metals. The adsorbent media reportedly achieves a maximum effluent concentration of 14 ppt for mercury [Smagula, 2010]. According to Siemens, the adsorption media technology vendor, the capital costs for a system including the two sets of adsorption media could range from $200,000 to $2,000,000, depending on the flow rate, influent concentrations, and system configurations. Siemens estimates that the O&M costs for the carbon-based media are approximately $2 per 1,000 gallons treated and the O&M costs for the ferric hydroxide media are approximately $1 per 1,000 gallons treated [Schultz, 2013].

Ion Exchange

Ion exchange systems are currently in use at power plants to pretreat boiler makeup water. These systems remove specific constituents from wastewater and therefore can target specific metals to be removed. The ion exchange resin works by substituting one ion for another on a specific resin, which must be replaced or regenerated when full [AEP, 2010]. The typical metals targeted by ion exchange systems include boron, cadmium, cobalt, copper, lead, mercury, nickel, uranium, vanadium, and zinc. Although the ion exchange process does not generate any residual sludge, it does generate a regenerant stream that contains the metals stripped from the wastewater [AEP, 2010].

In 2008, a pilot test was performed that evaluated mercury removals from filtration and ion exchange. Although the system was successful in removing trace mercury from FGD wastewater, the filtration process and not the ion exchange system removed most of the colloidal mercury [Goltz, 2009]. Additionally, EPA identified one plant that tested two ion exchange resins for treating FGD wastewater, specifically mercury removal. The plant determined that, while the resin can remove dissolved mercury, it is not effective at removing particulate or colloidal mercury [AEP, 2010].

EPA identified a model study performed at the University of North Carolina at Chapel Hill using ion exchange to remove bromides. Bromide removal was evaluated with a polyacrylate-based magnetic ion exchange (MIEX) resin and two polystyrene resins, Iona A-641 and Amberlite IRA910, using simulated natural waters containing natural organic matter, bicarbonate, chloride, and bromide. This study removed bromide and demonstrated that the polystyrene resins were the most effective. The study did not analyze the use of ion exchange resins on FGD wastewater; therefore, additional studies are needed to determine if this technology can remove bromide in FGD wastewater [Hsu, 2010].

EPA identified one plant that has installed an ion exchange system to treat FGD wastewater. This plant operates a full-scale ion exchange system that selectively targets the removal of boron, in conjunction with a chemical precipitation treatment stage to remove mercury and other metals and an anaerobic biological treatment stage to remove selenium [ERG, 2015a].

Electrocoagulation

Electrocoagulation uses an electrode to introduce an electric charge to the wastewater, which neutralizes the electrically charged colloidal particles allowing them to precipitate out of solution. These systems typically use aluminum or iron electrodes, which dissolve into the wastestream during the process. The dissolved metallic ions precipitate with the other pollutants in the wastewater and form insoluble metal hydroxides. EPRI believes additional polymer or supplemental coagulants may need to be added to the wastewater depending on the specific characteristics. These systems are typically used to treat small wastestreams, ranging from 10 to 25 gpm, but may also be able to treat wastestreams of up to 50 or 100 gpm [EPRI, 2007].

A bench- and pilot-scale study performed by the University of California, Los Angeles, examined the removal of bromine from raw lake water (*i.e.*, Castaic Lake) using the Wunsche and Kossuth processes. The Wunsche process uses monopolar carbon electrodes with a diaphragm to separate the anode and the cathode, while the Kossuth process uses dipolar carbon electrodes without a diaphragm. Both processes remove bromide by oxidizing the halogen to bromine, then applying heating and air stripping to volatize the bromine [Kimbrough, 2002]. The pilot-scale study of the electrolytic volatization method was recently published on naturally occurring bromine in Castaic Lake. This study determined that up to 35 percent bromide and 60 percent disinfection by-products could be removed through electrolysis [Kimbrough, 2006]. The bromide was volatized when passed between electrodes, clarified in an upflow sand clarifier, and filtered through a monomedium deep-bed anthracite coal filter. This study estimated that the costs for a demonstration-scale electrolytic reactor would be $1,549-2,099 per million gallons of water treated [Kimbrough, 2013].

Other Technologies

EPA obtained only limited information on other technologies including polymeric chelates, taconite tailings, nano-scale iron reagents, modular biological treatment systems, modular zero liquid discharge systems, and aluminum coagulation. In addition, EPRI is investigating various physical treatment technologies, primarily to remove mercury, including filtration [EPRI, 2008b].

7.2 Fly Ash Handling, Management, and Treatment Technologies

The information presented in this section is based on the Steam Electric Survey (2009 data), industry profile changes (see Section 4.5), and industry-provided information. During the Steam Electric Power Generating detailed study and rulemaking, EPA identified and investigated fly ash handling systems operated by coal-, petroleum coke-, and oil-fired steam electric power plants to collect and convey fly ash that are designed to minimize or eliminate the discharge of pollutants in fly ash handling transport water. As part of the final rulemaking, EPA considered chemical precipitation for treating fly ash transport water. However, EPA has not identified any plants using this treatment technology to treat fly ash transport water, although EPA has reviewed two literature sources that describe laboratory- or pilot-scale tests using the technology. Upon reviewing the discharge flow rate for fly ash transport water, however, EPA determined that the capital associated with chemical precipitation treatment were comparable to the costs of converting to dry handling technologies, despite being less effective at removing pollutants [ERG, 2015g]. Therefore, EPA did not select chemical precipitation as a treatment technology basis for control of fly ash in the final ELGs. Fly ash handling technologies evaluated by EPA are listed below and described in detail in this section.

Fly Ash Handling Systems that Generate Fly Ash Transport Water

- *Wet-Sluicing Systems:* These systems convey fly ash wet using water-powered hydraulic vacuums that pull the fly ash from the hopper to a separator/transfer tank, where the fly ash combines with the transport water flowing through the sluice pipes. Plants usually direct the resulting sluice to a surface impoundment. Some plants may wet sluice fly ash transport water in combination with a surface impoundment and recycle a portion or all water within the fly ash handling system.
- *Dense Slurry Systems:* These systems use a dry vacuum or pressure system to convey the dry fly ash to a silo (as described below for the "Dry Vacuum Systems" and "Pressure Systems"), but instead of using trucks to transport the fly ash to a landfill, the plant mixes the fly ash with a lower percentage of water compared to a wet-sluicing system and pumps the mixture to the landfill.[47]

[47] Because of the much smaller volume of water used for the DSS, relative to a traditional wet sluicing system, plants should be better able to engineer and operate the process so that there will be no discharge. To accomplish this, plants should divert stormwater away from the dense slurry to the extent practicable. If stormwater or other

<u>*Fly Ash Handling Systems that Do Not Generate Fly Ash Transport Water*</u>

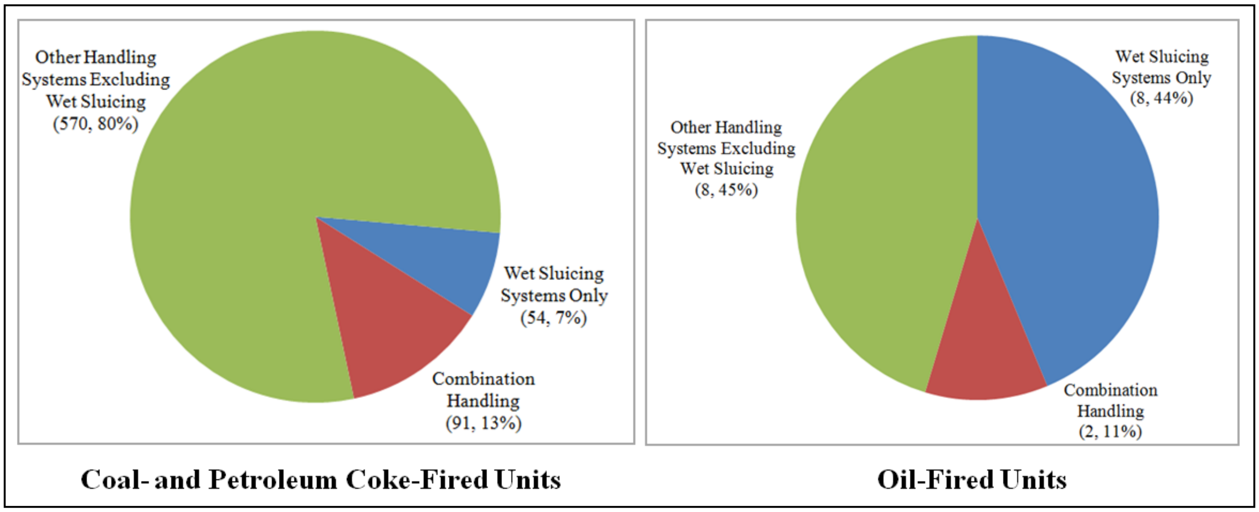
- *Wet Vacuum Pneumatic Systems:* These systems convey dry fly ash to a silo using water-powered hydraulic pumps to withdraw fly ash from the hopper and filter-receivers to collect the fly ash dry.
- *Dry Vacuum Systems:* These systems use a mechanical exhauster to move air, below atmospheric pressure, to pull the fly ash from the hoppers and convey it directly to a silo.
- *Pressure Systems:* These systems convey dry fly ash to a silo using air produced by a positive displacement blower directly.
- *Combined Vacuum/Pressure Systems:* These systems use a dry vacuum system to pull dry ash from the hoppers to a transfer station, where it is conveyed via a high-pressure conveying line directly to a silo.

EPA also identified mechanical systems as fly ash handling systems. The mechanical systems include manual or systematic approaches to remove fly ash (*e.g.*, scraping the sides of the boilers with sprayers or shovels, then collecting and removing the fly ash to an intermediate storage destination or disposal). Depending on the type of system used, it may or may not generate fly ash transport water.

Coal-, petroleum coke-, and oil-fired steam electric power plants use particulate control technologies such as electrostatic precipitators (ESPs) or baghouse filters to remove fly ash particles from the flue gas. Section 4 discusses the various types of fly ash collection methods used in the steam electric power generating industry. After the fly ash particles are captured by the ESP or baghouse filters, they are dropped into the collection hoppers. From the hoppers, the plants transport the fly ash via wet-sluicing, dry handling, or a combination of both to its next destination. From information provided in the Steam Electric Survey, EPA determined that 348 coal-, petroleum coke-, and oil-fired power plants, corresponding to 708 coal- and petroleum coke-fired generating units and 18 oil-fired generating units, generate fly ash. Most of these plants (approximately 76 percent) currently transport fly ash from all of their coal-, petroleum coke-, or oil-fired steam electric generating units using dry handling systems or other processes that do not require wet-sluicing. As shown in Figure 7-6, approximately 7 percent of coal- and petroleum coke-fired generating units operate wet-sluicing-only systems to collect fly ash, whereas 44 percent of the oil-fired generating units operate wet-sluicing systems. Based on Steam Electric Survey responses and publicly available data, EPA identified 18 plants (corresponding to 46 steam electric generating units) operating wet-sluicing systems that announced they will convert from wet to all dry handling operations no later than December 31, 2023 [ERG, 2015h]. Plants operating dry handling systems typically sell the collected fly ash to available markets or condition it with moisture prior to disposal in a landfill. For Figure 7-6, EPA grouped each coal- petroleum coke-, and oil-fired generating unit into one of the following three categories based on the type of fly ash handling system operated by the unit:

wastestreams come into contact with the dense slurry prior to completing the solidification and evaporation or encapsulation of the transport water, the commingled wastestream would need to comply with the zero discharge standard for fly ash and bottom ash transport water.

- Units with wet-sluicing systems only.
- Units with any other type(s) of handling system listed above (excluding wet-sluicing).
- Units that have multiple fly ash handling systems, including wet-sluicing.

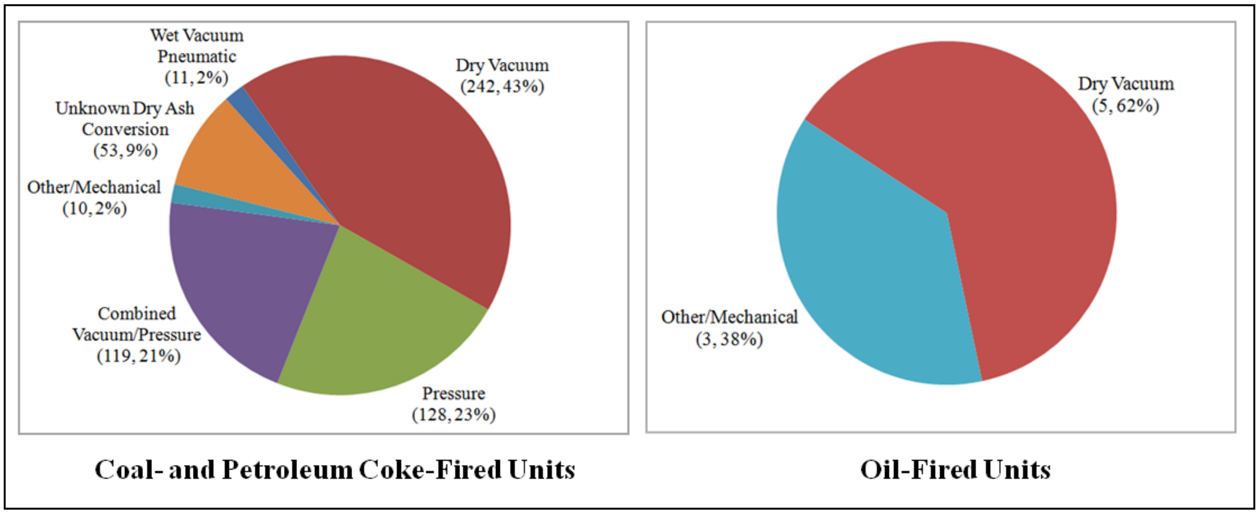


Source: Steam Electric Survey [ERG, 2015a].

Note: This figure represents the EPA population used in analyses for the ELGs which was developed using the Steam Electric Survey, industry profile changes (see Section 4.5), and additional industry-provided information.

Figure 7-6. Distribution of Fly Ash Handling Systems for Coal-, Petroleum Coke- and Oil-Fired Generating Units Reported in the Steam Electric Power Generating Industry

Based on information provided in the Steam Electric Survey, the number of plants installing fly ash handling systems other than wet-sluicing systems on new generating units, or converting existing generating units, is increasing due to their ability to market fly ash and reduce water consumption. Excluding wet-sluicing systems, the most common type of fly ash handling system currently in operation is the dry vacuum system (approximately 43 percent of non-wet-sluicing systems). Figure 7-7 shows the distribution of fly ash handling systems, excluding any generating units with wet-sluicing systems only or generating units with combination wet and dry handling systems, reported in the Steam Electric Survey for coal-, petroleum coke-, and oil-fired generating units. EPA grouped other handling systems, mechanical systems, and a combination of multiple systems, excluding wet sluicing, as "Other/Mechanical" in Figure 7-7.



Source: Steam Electric Survey [ERG, 2015a].

Note: This figure represents the EPA population used in analyses for the ELGs which was developed using the Steam Electric Survey, industry profile changes (see Section 4.5), and additional industry-provided information.

Note: The coal- and petroleum coke-fire units categorized as "Unknown Dry Ash Conversion" are fly ash handling conversions identified in the Updated Industry Profile Population described in Section 4.5.1. Therefore, EPA has verified that the steam electric generating unit is converting to dry fly ash handling prior to implementation of the final rule, but the type of system is unknown. For more information about EPA's incorporation of changes in the steam electric power generating industry, see Section 4.5.

Figure 7-7. Distribution of Fly Ash Handling System Types Other Than Wet Sluicing for Coal-, Petroleum Coke-, and Oil-fired Generating Units Reported in the Steam Electric Survey

The following sections discuss fly ash handling systems currently operating in the industry, including wet-sluicing systems and systems that minimize or eliminate the need for fly ash transport water.

7.2.1 Wet Sluicing System

In a wet-sluicing system, water-powered hydraulic vacuums create the vacuum for the initial withdrawal of fly ash from the hoppers. The vacuum pulls the ash to a separator/transfer tank, where the fly ash combines with the transport water flowing through the sluice pipes. The sluice pipes transfer the resulting fly ash slurry to an ash impoundment. Section 6.2.3 describes wet-sluicing operations in the steam electric power generating industry in more detail.

Fly ash transport water is typically treated in large surface impoundments, either completely separate from or commingled with other wastewaters. Impoundments vary in size, capacity, and age, and most impoundments receive other plant wastewater (*e.g.*, boiler blowdown, cooling water, low volume wastewater). Plants typically size the impoundments to provide enough residence time to reduce the TSS levels in the wastewater to meet the discharge requirement and to allow for a certain lifespan of the impoundment based on the expected rate of solids buildup within the impoundment.

Surface impoundments can reduce the amount of TSS in the wastewater discharge provided sufficient residence time. In addition to TSS, surface impoundments can also reduce some specific pollutants in the particulate form to varying degrees in the wastewater discharge. However, surface impoundments are not designed to reduce the amount of dissolved metals in the wastewater. While most plants discharge the impoundment overflow, some plants reuse a portion, or all, of the surface impoundment effluent as make-up for the fly ash transport water system. Additionally, some plants reuse the effluent for other plant operations. In these cases, much like discharged ash transport water, recycled transport water is often treated via only settling. Some plants, however, also have pH control systems to adjust the pH of the impoundment or the impoundment effluent stream to mitigate the potential for corrosion of the boiler and ash handling equipment.

Power plants operate and maintain the impoundments in varying ways. For example, some plants constantly remove settled ash solids from the inlet and stack them on the sides of the impoundment to dewater and build up its height. Alternatively, some plants periodically dredge the impoundment to remove the ash from the bottom and transfer the solids off site for disposal or to an on-site landfill, or use the solids to build up the height of the impoundment. Finally, some plants may not dredge the impoundment, but leave the ash in it permanently and, when it reaches its capacity, build a new ash impoundment and decommission the old one.

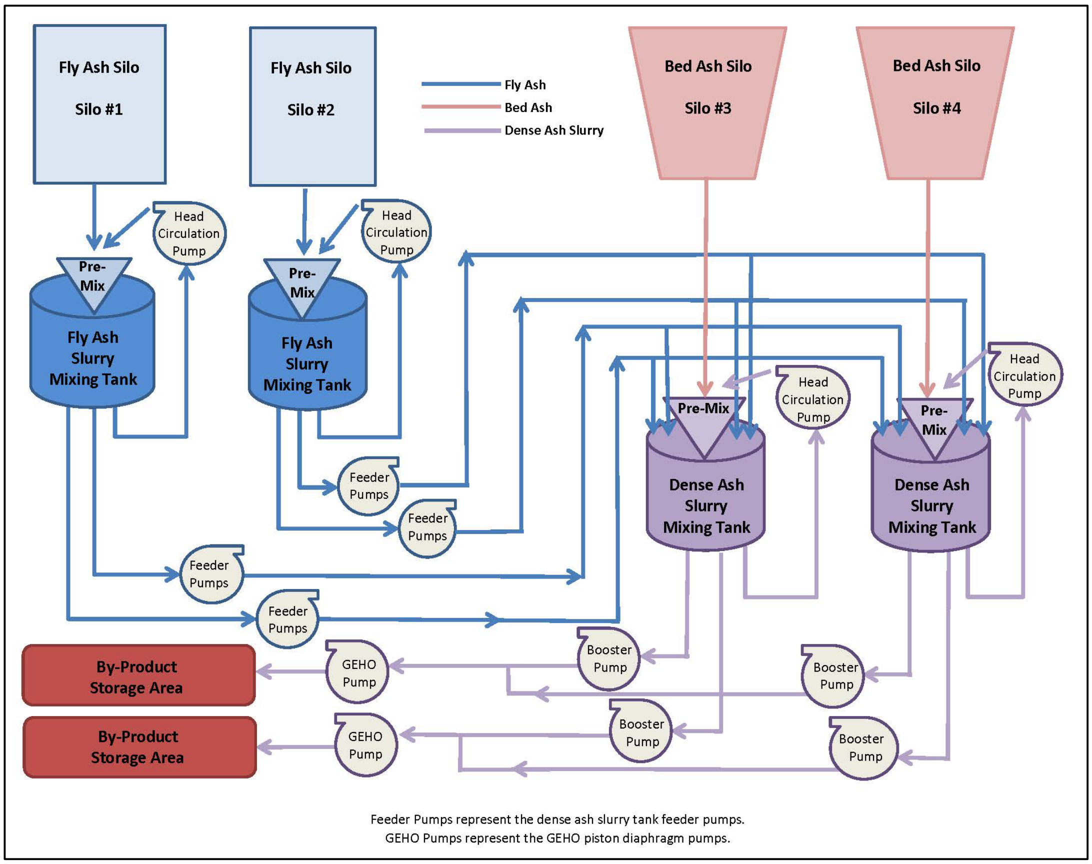
7.2.2 Fly Ash Dense Slurry System

The term "dense slurry" refers to a mixture of combustion residuals (*e.g.*, fly ash) with water, where the solid-to-water ratio is approximately 1:1. This ratio for the dense slurry system is much higher than the ratio used in the wet-sluicing system, which is typically in the range of 1:10 to 1:15 solid-to-water ratio. While bottom ash and FGD waste can be incorporated in a smaller fraction for some dense slurries, this handling system is predominately used in commercial applications to transport fly ash. A dense slurry system (DSS) is designed to pump the slurry to a disposal location (*i.e.*, landfill) where pozzolanic reactions occur to form a low hydraulic conductivity, high-compressible-strength solid product within 24 to 72 hours. As of spring 2012, there were 12 commercially applied DSSs in the world: four in Hungary, six in Romania, one in India, and one in the United States [GEA, 2014; GEA, 2013]. Because the DSS uses water to transport the fly ash to the disposal area, this system is considered to generate fly ash transport water and, therefore, the zero discharge requirements would apply to this system.

EPA investigated the only DSS operating in the United States, the Jacksonville Electric Authority Northside Generating Station (JEA Northside), during a site visit on April 8, 2014. JEA Northside has coal-, petroleum coke-, natural gas-, and landfill gas-fired generating units that have a circulating fluidized-bed boiler, where the plant injects limestone directly into the boiler for sulfur dioxide control. In 2002, JEA Northside installed the DSS to transport fly ash and bottom ash to a by-product storage area, due to traffic and scaling concerns.[48] The solid by-product is either marketed (*e.g.*, binder for landfills, binder for remediation sites, binder for pond closures, interim road cover, or secondary road cover) or landfilled. The DSS was designed to

[48] JEA Northside decided installing a traditional dry ash handling system was not feasible because of the volume of trucks needed and concern for increased limestone in the ash-causing scaling issues in the surface impoundment used to store fly ash.

handle all the fly ash and bottom ash produced by JEA Northside's two generating units and designed by the United Conveyor Corporation.[49] The fly ash falls out of the flue gas stream in the economizer or is collected after the spray dryer absorber in fabric filter baghouses and pneumatically conveyed to fly ash silos. In addition, the bottom ash flows out the bottom of the boiler into a stripper/cooler and is carried by a series of mechanical drag chains to a clinker grinder. The ground bottom ash drops into a surge hopper and is pneumatically conveyed to bottom ash silos (bed ash silos in Figure 7-8). Next the fly ash is mixed with makeup water and pumped to the dense ash slurry mixing tank for blending with bottom ash and additional makeup water. Then the dense slurry mixture is pumped to the by-product storage area [ERG, 2014b]. See Figure 7-8 for a schematic of the JEA Northside DSS for fly ash and bottom ash.



Source: JEA Northside Site Visit Notes [ERG, 2014b].

Figure 7-8. JEA Northside Dense Slurry System Material Flow Diagram

The JEA Northside DSS conveys ash from only one fly and bottom ash silo at a time and is able to mix 220-250 tons of ash per minute. The dense slurry is approximately 60 percent solids by weight but the ratio of fly ash, bottom ash, and makeup water depends on the type of

[49] Unit 1 and Unit 2 each generate approximately 500 tons of fly ash and 700 tons of bottom ash per day and 500,000 tons of DSS by-product per year. The diaphragm pumps (GEHO pumps in Figure 7-8) were obtained from a European-based company.

coal burned and desired market product. The DSS by-product is dried, milled, and tested for strength and waste stabilization benchmarks to ensure it complies with market specifications.

Because JEA Northside injects limestone into the boiler for sulfur dioxide control, the fly ash contains excess calcium compared to fly ash generated for a typical coal-fired generating unit. The excess calcium aids in the pozzolanic reactions that occur at the landfill to make the cementitious material. Therefore, for most coal-fired generating units to effectively operate a fly ash dense slurry system, the plant would need to mix the fly ash with lime or limestone and water prior to transferring the dense slurry to the landfill for disposal.

7.2.3 Wet Vacuum Pneumatic System

Wet vacuum pneumatic systems are fly ash handling systems that use water-powered hydraulic vacuums to create the vacuum for the initial withdrawal of fly ash from the hoppers, similar to wet-sluicing systems. However, the fly ash is not directed to a separator/transfer tank and is not combined with the water flowing through the sluice pipes. Instead, the fly ash is captured by a filter-receiver (*i.e.*, bag filter with a receiving tank) placed before the junction where the fly ash would have been mixed with the sluice water. Wet vacuum pneumatic systems are able to convey dry ash up to 50 tons per hour (tph) and 500 feet [Mooney, 2010]. From the filter-receiver tank, the system deposits the fly ash into a silo. The silo receiving the ash is equipped with an exhauster that displaces the air from the vacuum created by the hydraulic pump and a baghouse filter that captures the fly ash in the silo.

From the silo, the fly ash is either sold to an available market or moisture conditioned and sent to a landfill. For unloading the ash for sale or conditioning, silos are usually equipped with dry unloaders, wet unloaders, or a combination of unloading equipment for each disposal method. The dry unloaders are conical shaped spouts, with a vacuum system to control fugitive dust. The system loads the ash, with a moisture content of less than 1 percent, from the spout into vacuum-sealed trucks, which transport the ash to the market destination. Wet unloaders use pugmills to simultaneously unload the fly ash and increase the moisture content of the ash by conditioning it with water. Pugmills condition the fly ash to between 15 and 20 percent moisture before it is unloaded into uncovered dump trucks. Responses in the Steam Electric Survey show that plants use the following types of water to moisture condition fly ash at silo locations:

- Raw intake water.
- Intake water that is treated prior to use.
- Cooling tower blowdown.
- General runoff.
- Floor drain wastewater.
- Leachate.
- Recycled process water.
- FGD wastewater.
- Bottom ash transport water.

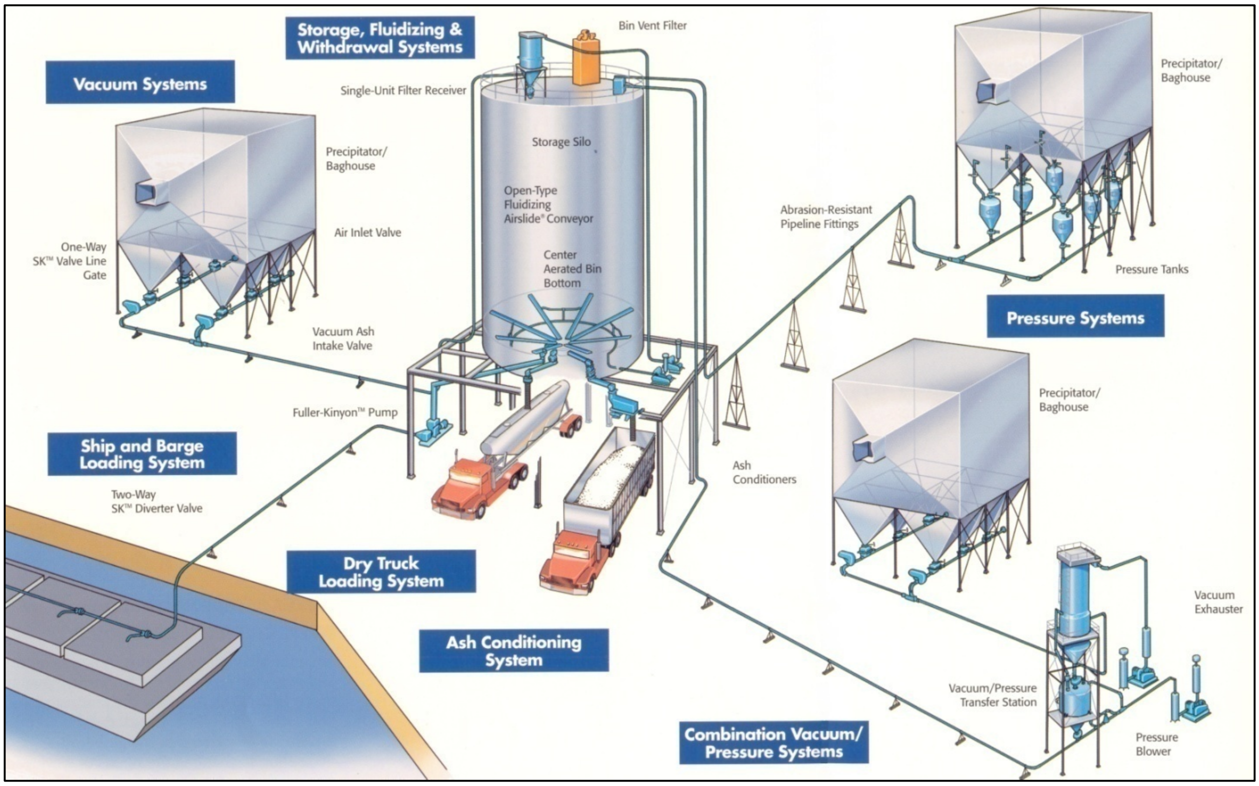
After moisture conditioning and loading, the ash is transported by truck to the landfill. Some silos are equipped with both wet and dry unloading capabilities for flexibility with the fly ash market.

The wet vacuum pneumatic system is not commonly installed on new generating units; however, the system is attractive to plants that are converting existing generating units from wet to dry fly ash handling because it allows the plants to reuse the existing vacuum source. The bag filters used to collect the fly ash prior to mixing with the vacuum water are unable to remove 100 percent of the fly ash; therefore, a small amount of fly ash contaminates the water generated from the system. Different from fly ash transport water associated with wet-sluicing systems, whose purpose is to transport ash to an impoundment or other treatment, the purpose of the wet vacuum pneumatic vacuum water is strictly to create the vacuum to move the ash to the silo, and not to transport the ash to other locations outside of the system. While this stream is contaminated with a small amount of carryover fly ash, according to survey responses, most plants operating this type of system transfer the wastewater to an impoundment and reuse the overflow in the wet vacuum pneumatic system. In addition, the outage required for installing or converting to vacuum systems is about 6 to 8 weeks if the plant is not retaining the ash collection hoppers. However, if the plant retains the fly ash hopper and branch lines, the silo and wet vacuum pneumatic system can be installed nearby while the steam electric generating unit is on line and will only take a few days to tie in to existing pipe headers and diverter valves. Therefore, this installation or conversion can occur during normal scheduled maintenance outages [CBPG, 2010].

7.2.4 Dry Vacuum System

Dry vacuum systems use a mechanical exhauster to move air, below atmospheric pressure, to pull the fly ash from the hoppers and convey it directly to a silo. Dry vacuum systems can convey dry ash up to 60 tph and typically up to 1,000 feet [Mooney, 2010]. From discussions with fly ash handling vendors, EPA determined that some dry vacuum systems can convey ash up to 1,500 feet (at 30 to 50 tph), depending on capacity requirements, line configuration, and plant altitude [McDonough, 2011]. The fly ash empties from the hoppers into the conveying system via a material handling valve. Similar to the silo configuration described in Section 7.2.3, the silo is equipped with an aeration system and baghouse filter to receive the fly ash from the hopper. From the silo, the plant either sells the fly ash or disposes of it in a landfill. The unloading procedures described in Section 7.2.3 also apply to the dry vacuum system. See Figure 7-9 for a schematic of a typical dry vacuum fly ash handling system set-up. As shown in Figure 7-7, the dry vacuum system is the most commonly used dry fly ash handling system for coal- and petroleum coke-fired generating units, accounting for 43 percent of all installations.

Dry vacuum systems have fewer components than pressure systems, allowing for more flexibility for installing them under existing hoppers. Dry vacuum systems can also start and stop automatically during operation due to the components and nature of the vacuum system. Vacuum systems maintain cleaner operations than other conveyance methods because any leaks simply pull ambient air into the system [Babcock & Wilcox, 2005]. In addition, the outage required to install or convert to vacuum systems is about 6 to 8 weeks if the plant is not retaining the ash collection hoppers. However, if the plant retains the fly ash hopper and branch lines, the silo and the dry vacuum system can be installed nearby while the steam electric generating unit is on line and will only take a few days to tie in to existing pipe headers and diverter valves. Therefore, this installation or conversion can occur during normal scheduled maintenance outages [CBPG, 2010].

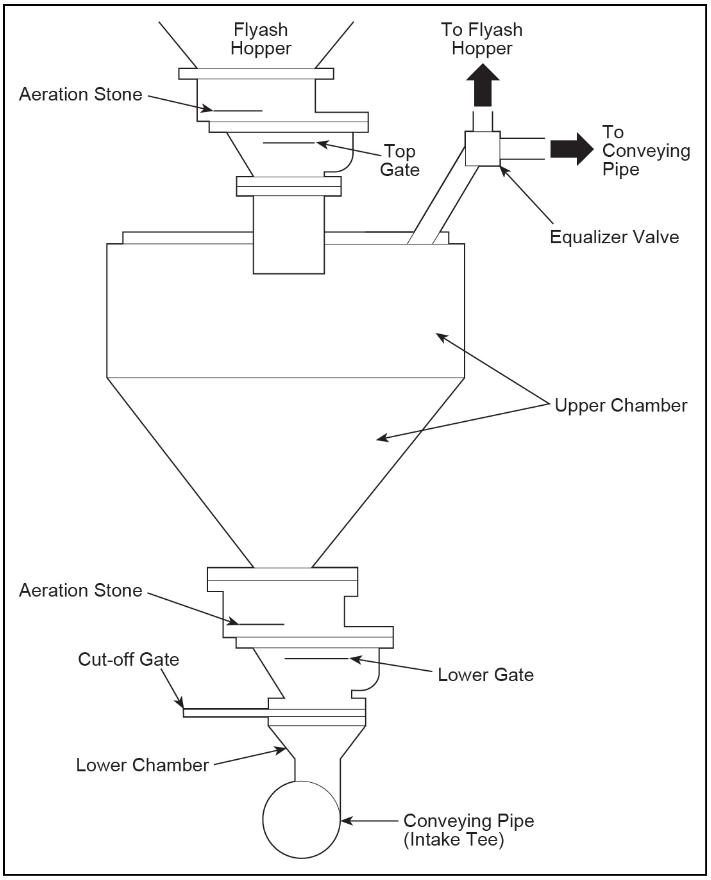


Graphic reprinted with permission from FLSmidth Inc. [FLSmidth, 2012].

Figure 7-9. Schematic of Dry Vacuum, Pressure, and Combined Vacuum/Pressure System

7.2.5 Pressure System

A pressurized system uses air produced by a positive displacement blower to convey ash directly from the hoppers to a silo. Each hopper collecting ash is equipped with airlock valves that transfer the fly ash from low pressure to high pressure in the conveying line, shown in Figure 7-10. The airlock valves are transfer points that accept ash at a low pressure, separate it from the air pressure in the bottom of the hoppers, and then release the ash to the high-pressure conveying line [Babcock & Wilcox, 2005]. Once in the conveying line, the system transports the fly ash directly to the silo. Because of the high-pressure air, the aeration system at the silo is less sophisticated than those used for wet vacuum pneumatic systems (Section 7.2.3), because a vacuum is not involved in the operation. From the silo, the plant either sells the fly ash or disposes of it in a landfill. The unloading procedures described in Section 7.2.3 also apply to the pressure system. See Figure 7-9 for a schematic of a typical pressure fly ash handling system set-up.



Graphic reprinted with permission from Steve Stultz [Babcock & Wilcox, 2005].

Figure 7-10. Pressure System Airlock Valve

Plants use pressure systems to convey more ash longer distances compared to a dry vacuum systems: 100 tph of fly ash for distances up to 5,000 feet [Mooney, 2010]. Depending on the conveying capacity requirements, pressurized systems can convey ash up to 8,000 feet [McDonough, 2011]. The airlock valves (see Figure 7-10) at the bottom of the hoppers, however, require a significant amount of available headspace for installation; therefore, not all plants currently operating wet-sluicing systems would be able to easily install pressure systems without significant capital investment to raise the bottom of the hopper. Additionally, pressure systems are not able to stop and start automatically because airlock valves require manual stop and restart. Pressure systems can also experience leaks of fine ash particulates, usually at the piping joints due to the high pressure in the conveying line [Babcock & Wilcox, 2005]. In addition, the outage required to install or convert to pressure systems is about 8 to 12 weeks if the plant is not retaining the ash collection hoppers. However, if the plant retains the fly ash hopper and branch lines, the silo and the pressure system can be installed nearby while the steam electric generating unit is on line and will only take a few days to tie in to existing pipe headers and diverter valves. Therefore, this installation or conversion can occur during normal scheduled maintenance outages [CBPG, 2010].

7.2.6 Combined Vacuum/Pressure System

Combined vacuum/pressure fly ash handling systems utilize both dry vacuum and pressure systems. A mechanical exhauster moves air, below atmospheric pressure, to pull the fly ash from the hoppers, similar to the dry vacuum system. After a short distance, approximately 800 feet or less, the system directs the fly ash to an intermediate transfer vessel, such as a filter separator, where it transfers the ash from the vacuum (low pressure) to ambient pressure. From the filter separator, the system transfers the fly ash to airlock valves that convey the ash to the high-pressure conveying line. This conveying line can convey ash up to 8,000 feet [McDonough, 2011] directly to a silo. Because the second portion of the combination system is a pressure system, the aeration system at the silo is less sophisticated than for a dry vacuum system, as described above for the pressure system. From the silo, the plant either sells the fly ash or disposes of it in a landfill. The unloading procedures described in Section 7.2.3 also apply to the combined vacuum/pressure system. See Figure 7-9 for a schematic of a typical combined vacuum/pressure fly ash handling system.

Plants use combination systems to transport fly ash longer distances than vacuum systems alone can, while retaining the space advantages of the dry vacuum system (*i.e.*, no additional headspace required under the hopper). Manual stop and restart is still required to transfer fly ash from the vacuum to the pressure system. Additionally, fine ash particles will also leak at the piping joints due to the high-pressure portion of the system [Babcock & Wilcox, 2005]. In addition, the outage required to install or convert to a combined vacuum pressure systems is about 8 to 12 weeks if the plant is not retaining the ash collection hoppers. However, if the plant retains the fly ash hopper and branch lines, the silo and the combination vacuum pressure system can be installed nearby while the steam electric generating unit is on line and will only take a few days to tie in to existing pipe headers and diverter valves. Therefore, this installation or conversion can occur during normal scheduled maintenance outages [CBPG, 2010].

7.2.7 Mechanical System

Mechanical fly ash handling systems usually service generating units that generate a low volume of fly ash. These generating units are usually oil-fired and typically produce less ash than coal-fired generating units. Mechanical systems include any manual or systematic approach to removing fly ash. Based on responses to the Steam Electric Survey, the systems include periodic scheduled cleanings of the boiler or manual removal. Manual removal includes scraping the sides of the boilers with sprayers or shovels, then collecting and removing the fly ash to an intermediate storage destination or sending it to a landfill.

EPA is also aware of one plant that retrofitted an oil-fired generating unit with a mechanical system that included collecting fly ash with vactor trucks. A vactor truck is a vacuum with a portable pump to collect the fly ash into the roll-off dumpster. The collection system includes vacuum piping that transports fly ash in the bottom of the hoppers to a roll-off vacuum container. For plants with multiple hoppers, the fly ash is conveyed to the roll-off vacuum container one hopper at a time by closing the valves below the other hoppers. A vactor truck connects to the roll-off container, vacuums the fly ash to the truck, and disposes of the fly ash off site. Steam electric power plants can operate this system themselves or contract the vactor truck operation and off-site disposal to an outside vendor [ERG, 2015a].

7.3 BOTTOM ASH HANDLING, MANAGEMENT, AND TREATMENT TECHNOLOGIES

The information presented in this section is based on the Steam Electric Survey (2009 data), industry profile changes (see Section 4.5), and industry-provided information. During the Steam Electric Power Generating detailed study and rulemaking, EPA identified and investigated bottom ash handling systems operated by coal-, petroleum coke-, and oil-fired steam electric power plants to collect and convey bottom ash, that are designed to minimize or eliminate the discharge of pollutants associated with bottom ash transport water. As part of the final ELGs, EPA considered chemical precipitation for treating bottom ash transport water. However, upon reviewing the discharge flow rate for bottom ash transport water, EPA determined that the capital associated with chemical precipitation treatment were comparable to the costs of converting to dry handling or closed-loop recycle technologies, despite being less effective at removing pollutants [ERG, 2015g]. Therefore, EPA did not select chemical precipitation as a treatment technology basis for controlling bottom ash for the final ELGs. Bottom ash handling technologies evaluated by EPA, including a brief description of each, are listed below and described in detail in this section.

Bottom Ash Handling Systems that Generate Bottom Ash Transport Water

- *Wet-Sluicing Systems:* These systems convey bottom ash wet from a quench bath underneath the boiler via slurry lines usually to a surface impoundment. Some plants may wet sluice bottom ash transport water in combination with a surface impoundment, dewatering bin, and/or settling tank to recycle a portion or all water within the bottom ash handling system.
- *Remote Mechanical Drag System*: These systems transport bottom ash using the same processes as wet-sluicing systems to a remote mechanical drag system. A drag chain conveyor pulls the bottom ash out of the water bath on an incline to dewater the bottom ash.
- *Dense Slurry Systems:* These systems use a dry vacuum or pressure system to convey the bottom ash to a silo (as described below for the "Dry Vacuum or Pressure System"), but instead of using trucks to transport the bottom ash to a landfill, the plant mixes the bottom ash with a lower percentage of water compared to a wet-sluicing system and pumps the mixture to the landfill.[50]

Bottom Ash Handling Systems that Do Not Generate Bottom Ash Transport Water

- *Mechanical Drag System*: These systems are located directly underneath the boiler. The bottom ash is collected in a water quench bath. A drag chain conveyor pulls the bottom ash out of the water bath on an incline to dewater the bottom ash.

[50] Because of the much smaller volume of water used for the DSS, relative to a traditional wet sluicing system, plants should be better able to engineer and operate the process so that there will be no discharge. To accomplish this, plants should divert stormwater away from the dense slurry to the extent practicable. If stormwater or other wastestreams come into contact with the dense slurry prior to completing the solidification and evaporation or encapsulation of the transport water, the commingled wastestream would need to comply with the zero discharge standard for fly ash and bottom ash transport water.

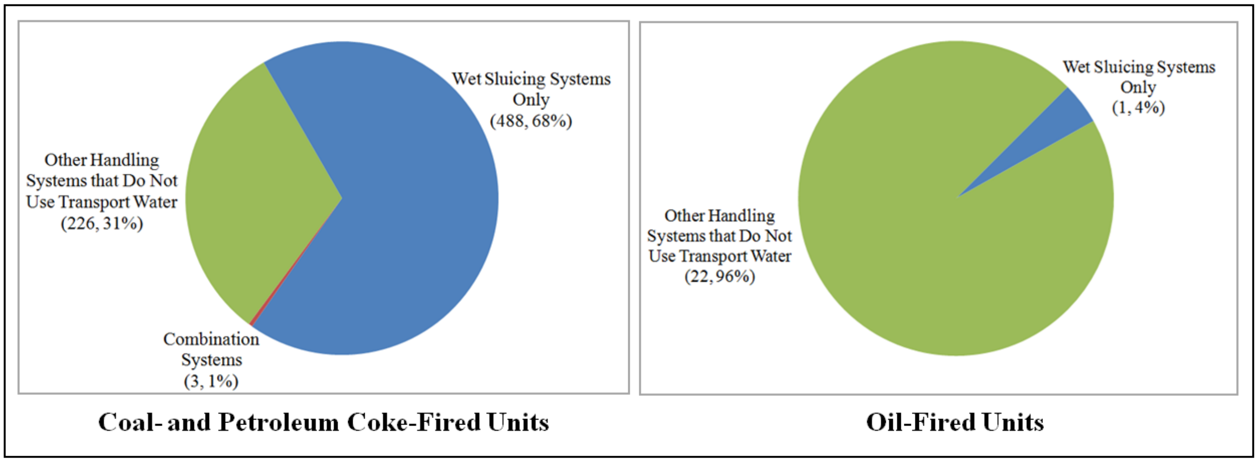
- *Dry Mechanical Conveyor*: These systems are located directly underneath the boiler. The system uses ambient air to cool the bottom ash in the boiler and then transports the ash out of the boiler using a conveyor. There is no water used in this process.
- *Dry Vacuum or Pressure System*: These systems transport bottom ash from the boiler to a dry hopper without using any water. Air is percolated through the ash to cool it and combust unburned carbon. Cooled ash then drops to a crusher and is conveyed via vacuum or pressure to an intermediate storage destination.
- *Vibratory Belt System*: These systems deposit bottom ash on a vibratory conveyor trough, where the ash is air-cooled and ultimately moved through the conveyor deck to an intermediate storage destination.

EPA also identified mechanical systems as bottom ash handling systems. The mechanical systems include manual or systematic approaches to remove bottom ash (*e.g.*, scraping the sides of the boilers with sprayers or shovels, then collecting and removing the bottom ash to an intermediate storage destination or disposal). Depending on the type of system used, it may or may not generate bottom ash transport water.

From information provided in the Steam Electric Survey, EPA determined that 350 coal-, petroleum coke-, and oil-fired power plants, corresponding to 717 coal- or petroleum coke-fired generating units and 23 oil-fired generating units, generate bottom ash. Figure 7-11 shows a distribution of the coal-, petroleum coke-, and oil-fired generating units based on their type of bottom ash handling system(s). For this figure, the systems are grouped into the following three categories:

- Generating units with wet-sluicing systems only.
- Generating units with systems that eliminate bottom ash transport water.
- Generating units with multiple bottom ash handling systems, including wet sluicing.

Approximately 58 percent of the 350 steam electric power plants mentioned above currently operate wet-sluicing handling systems on all steam electric generating units that produce bottom ash. The remaining plants currently operate systems other than wet-sluicing systems, exclusively or in combination with wet-sluicing systems. As shown in Figure 7-11, approximately 68 percent of coal- and petroleum coke-fired generating units use only wet-sluicing systems to handle bottom ash, whereas over 95 percent of oil-fired units use systems that do not use bottom ash transport water. Based on survey data and publicly available data, EPA identified 17 plants (corresponding to 53 steam electric generating units) operating wet-sluicing systems that will convert from wet to all dry handling operations no later than December 31, 2023 [ERG, 2015h]. After collecting the ash, plants can sell dewatered or dry bottom ash or send it to a landfill.

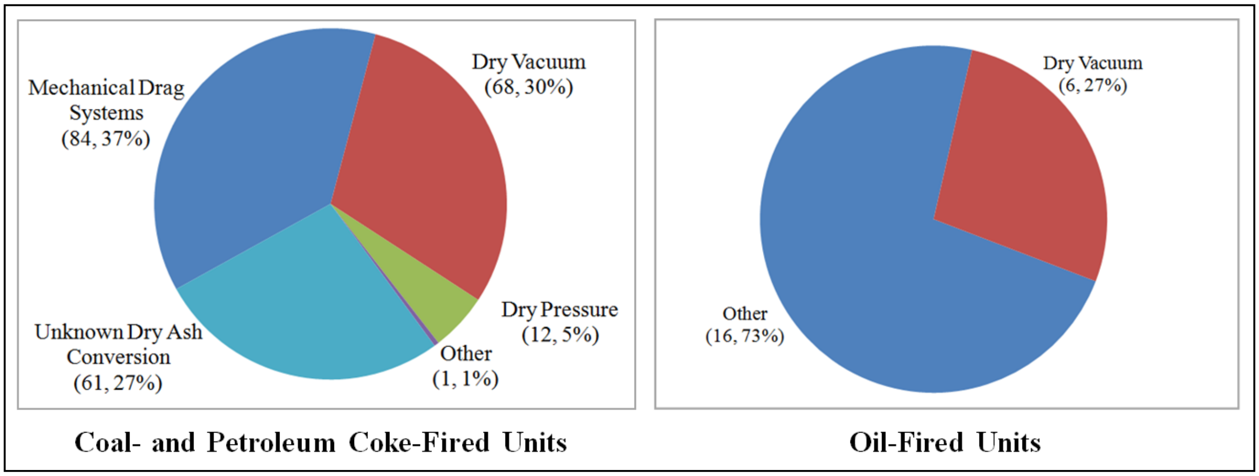


Source: Steam Electric Survey [ERG, 2015a].

Note: This figure represents the EPA population used in analyses for the ELGs, which was developed using the Steam Electric Survey, industry profile changes (see Section 4.5), and additional industry-provided information.

Figure 7-11. Distribution of Bottom Ash Handling Systems for Coal-, Petroleum Coke-, and Oil-Fired Units Reported in the Steam Electric Survey

Information provided in the Steam Electric Survey and vendor data shows the number of plants installing mechanical drag systems on new generating units is increasing [McDonough, 2011]. From the Steam Electric Survey and Energy Information Administration (EIA) data, approximately 65 percent of steam electric generating units that began operating in the last 10 to 25 years are installing handling systems other than wet sluicing. Of those systems, 67 percent are mechanical drag systems [ERG, 2015a]. Figure 7-12 shows the distribution of bottom ash handling systems, excluding generating units with any wet-sluicing systems, reported in the Steam Electric Survey for coal-, petroleum coke-, and oil-fired generating units. Steam electric generating units with more than one type of bottom ash handling system, excluding wet-sluicing systems, or other mechanical systems were included as "Other" in Figure 7-12.



Source: Steam Electric Survey [ERG, 2015a].

Note: This figure represents the EPA population used in analyses for the ELGs, which was developed using the Steam Electric Survey, industry profile changes (see Section 4.5), and additional industry-provided information.

Note: The coal- and petroleum coke-fire units categorized as "Unknown Dry Ash Conversion" are bottom ash handling conversions identified in the Updated Industry Profile Population described in Section 4.5.1. Therefore, EPA has verified that the steam electric generating unit is converting to dry or closed-loop bottom ash handling prior to implementation of the final rule, but the type of system is unknown. For more information about EPA's incorporation of changes in the steam electric power generating industry, see Section 4.5.

Figure 7-12. Distribution of Bottom Ash Handling System Types Other Than Wet Sluicing for Coal-, Petroleum Coke-, and Oil-Fired Generating Units Reported in the Steam Electric Survey

Steam electric generating units that produce bottom ash collect the ash particles in hoppers, or other types of collection equipment, directly below the boilers. Generally, boilers are sloped inward and have an opening at the bottom to allow the bottom ash to feed by gravity into the ash collection system (*e.g.*, hoppers or the trough of a mechanical drag system). The following sections discuss current bottom ash wet-sluicing systems in the industry in addition to those that minimize or eliminate the discharge of bottom ash transport water.

7.3.1 Wet-Sluicing System

In a wet-sluicing system, bottom ash hoppers are filled with water to quench the hot bottom ash as it enters the hopper. Once the hoppers are full of bottom ash, a gate at the bottom of the hopper opens and the ash is directed to grinders to grind the bottom ash into smaller pieces [Babcock & Wilcox, 2005]. As the gates at the bottom of the hoppers open, they release the bottom ash and water, emptying the water quench bath in the hopper. Once the gates are closed, the bottom of the hopper fills with water. Because of the batch style process, bottom ash removal is not continuous.

After the bottom ash passes through the grinder, the system feeds it to the conveying line. The plant then dilutes the bottom ash with water to approximately 20 percent solids (by weight) and pumps the bottom ash slurry to an impoundment or a dewatering bin for solids removal. Section 6.2.3 describes wet-sluicing operations in the steam electric power generating industry in more detail.

Similar to fly ash transport water, bottom ash transport water is typically treated in large surface impoundments, either completely separate from or commingled with other wastewaters. See Section 7.2.1 for more information on how plants typically maintain ash impoundments.

As stated above, the bottom ash slurry can either be transferred to an impoundment or a dewatering bin. Plants with dewatering bin systems usually operate two dewatering bins so that while one bin fills, the other is dewatered and the ash is unloaded into trucks or rail cars. As the bins fill with bottom ash transport water, the particulates are contained at the bottom of the bin. Excess water in the bin flows over a serrated overflow weir, leaving the dewatering bin. At the top of the bin, an underflow baffle prevents finer particulates from floating out of the bin with the overflow [Babcock & Wilcox, 2005]. As the dewatering bin continues to receive bottom ash transport water, it eventually reaches its solids loading capacity, at which time the plant directs the bottom ash transport water to another dewatering bin and begins the decant process in the first bin. The bottom ash transport water exiting the top of the bin and the water that is decanted from the bin prior to removing the solids can either overflow to additional settling tanks or be pumped to a surface impoundment. Figure 7-13 presents a diagram of a dewatering bin system with additional settling tanks after the dewatering bins.

Graphic reprinted with permission from United Conveyor Corporation [UCC, 2009].

Figure 7-13. Bottom Ash Dewatering Bin System

7.3.2 Bottom Ash Dense Slurry System

The DSS for handling bottom ash is similar to the DSS for handling fly ash. As described in Section 7.2.2, the DSS is a system that pumps a mixture of combustion residuals with water, where the solid-to-water ratio is approximately 1:1. This ratio for the dense slurry system is much higher than the solid-to-water ratio used in the wet-sluicing system, which is typically in the range of 1:10 to 1:15. A DSS is designed to pump the slurry to a disposal location (*i.e.*, landfill) where pozzolanic reactions occur to form a low hydraulic conductivity, high-compressible-strength solid product within 24 to 72 hours. See Section 7.2.2 for additional information regarding the operation of the DSS at JEA Northside [ERG, 2014b; GEA, 2013]. Because the DSS uses water to transport the bottom ash to the disposal area, this system is considered to generate bottom ash transport water and, therefore, the zero discharge requirements would apply to this system.

7.3.3 Mechanical Drag System

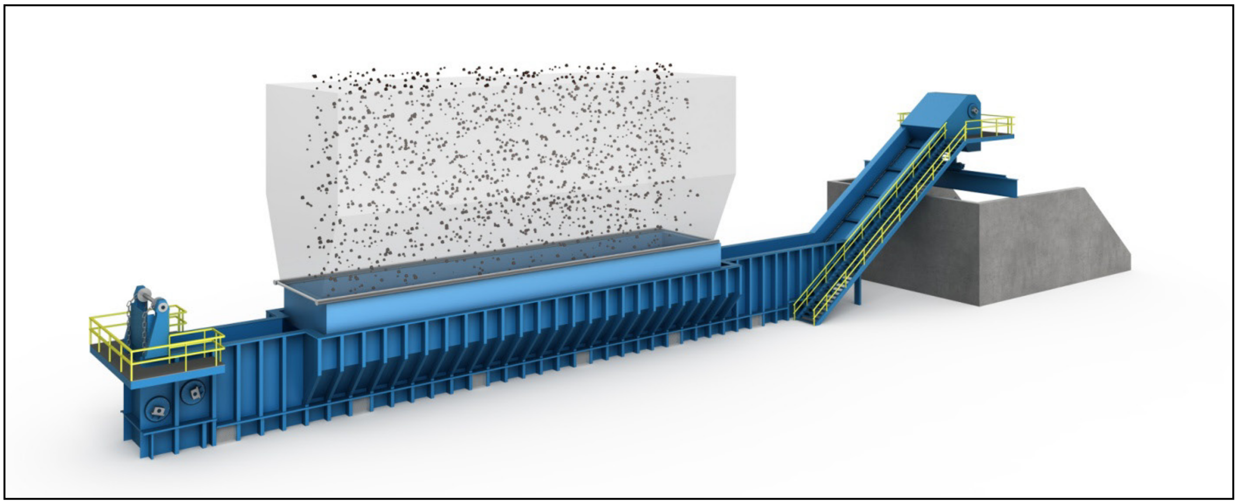
Mechanical drag systems collect bottom ash from the bottom of the boiler, similar to the description above for the wet-sluicing system. As shown in Figure 7-12, there are 84 units that operate a mechanical drag system, which represent 34 percent of all coal-, petroleum coke-, and oil-fired steam electric generating units which operate systems other than wet sluicing. Because of the shape of the boiler, explained above, the bottom ash is gravity fed through the opening at the bottom of the boiler, through a transition chute, and into a water-filled trough. The water bath in the trough quenches the hot bottom ash as it falls from the boiler and seals the boiler gases. The drag system comprises a drag chain with a parallel pair of chains. The chains are attached with crossbars at regular intervals along the bottom of the water bath and move in a continuous loop towards the far end of the bath. At the far end, the drag chain begins moving up an incline, which dewaters the bottom ash by gravity, draining the water back to the trough as the bottom ash moves upward. Because the bottom ash falls directly into the water bath from the bottom of the boiler and the drag chain moves constantly on a loop, bottom ash removal is continuous. The dewatered bottom ash is often conveyed to a nearby collection area, such as a small bunker outside the boiler building, from which it is loaded onto trucks and either sold or transported to a landfill. See Figure 7-14 for a diagram of a mechanical drag system.

Because the trough has a water bath, the mechanical drag system does generate some wastewater (*i.e.*, residual water that collects in the storage area as the bottom ash continues to dewater). This wastewater, however, is typically completely recycled back to the quench water bath. Additionally, EPA does not consider this wastewater to be bottom ash transport water because the transport mechanism is the drag chain, not the water. Therefore, the MDS design does not include operation as a closed-loop system, eliminating the need for a heat exchanger. [51]

Mechanical drag systems come in various standard widths and require little headspace under the boiler; however, the system may not be suitable for all boiler configurations. For example, existing boilers located below grade are usually surrounded with support columns and positioned close to the floor with the sluice lines 1 to 2 feet above the ground. A mechanical drag system would be difficult to install with such space limitations. These systems are not able to combine and collect bottom ash from multiple boilers and generally need a straight exit from the boiler to the outside of the building. In addition, these systems may be susceptible to maintenance outages because bottom ash fragments fall directly onto the drag chain. The outage

[51] The MDS does not need to operate as a closed-loop system because it does not use water as the transport mechanism to remove the bottom ash from the boiler; the conveyor is the transport mechanism. Therefore, any water leaving with the bottom ash does not fall under the definition of "bottom ash transport water," but rather, is a low volume waste.

required to install or convert to mechanical drag systems is about 6 to 8 weeks to demolish existing equipment and install new equipment. Therefore, this installation or conversion can occur during normal scheduled maintenance outages [CBPG, 2010].

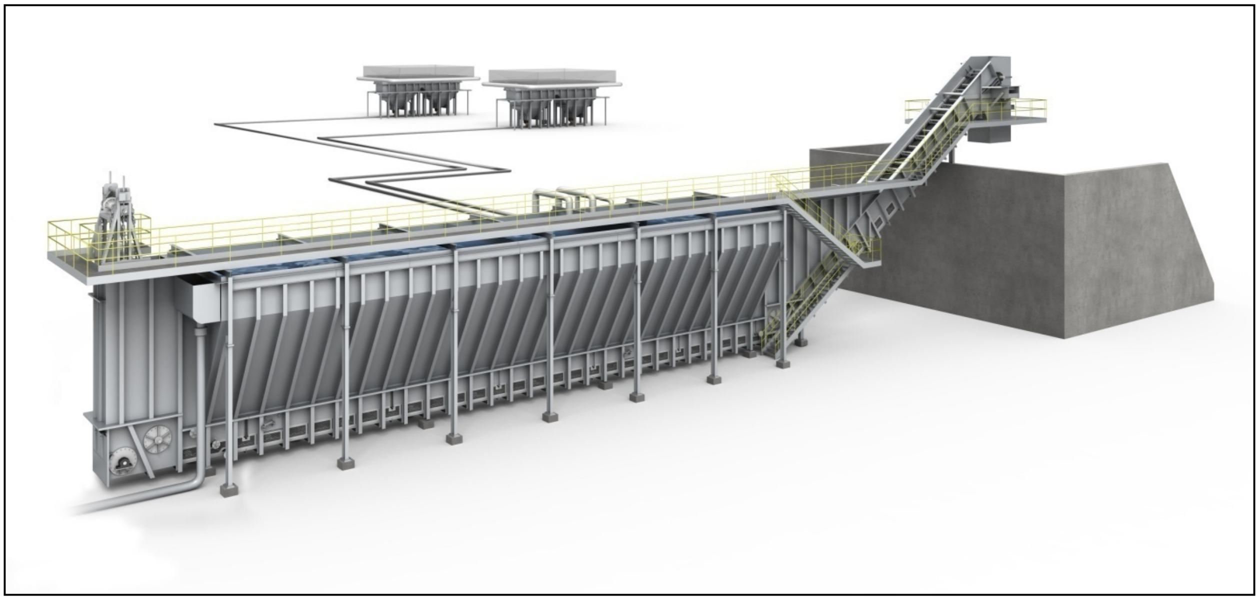


Graphic reprinted with permission from United Conveyor Corporation [UCC, 2009].

Figure 7-14. Mechanical Drag System

7.3.4 Remote Mechanical Drag System

Remote mechanical drag systems collect bottom ash using the same operations and equipment as wet-sluicing systems at the bottom of the boiler. However, instead of sluicing the bottom ash directly to an impoundment, the plant pumps the bottom ash transport water to a remote mechanical drag system. This type of system has the same configuration as a mechanical drag system except that it has additional dewatering equipment in the trough and is not located under the boiler, but rather in an open space on the plant property. See Figure 7-15 for a diagram of a remote mechanical drag system. Plants converting existing bottom ash handling systems can use this system where space or other restrictions limit the changes that can be made to the bottom of the boiler. Currently, one U.S. plant is operating and another plant is installing a remote mechanical drag system [ERG, 2015i, McDonough, 2012b].

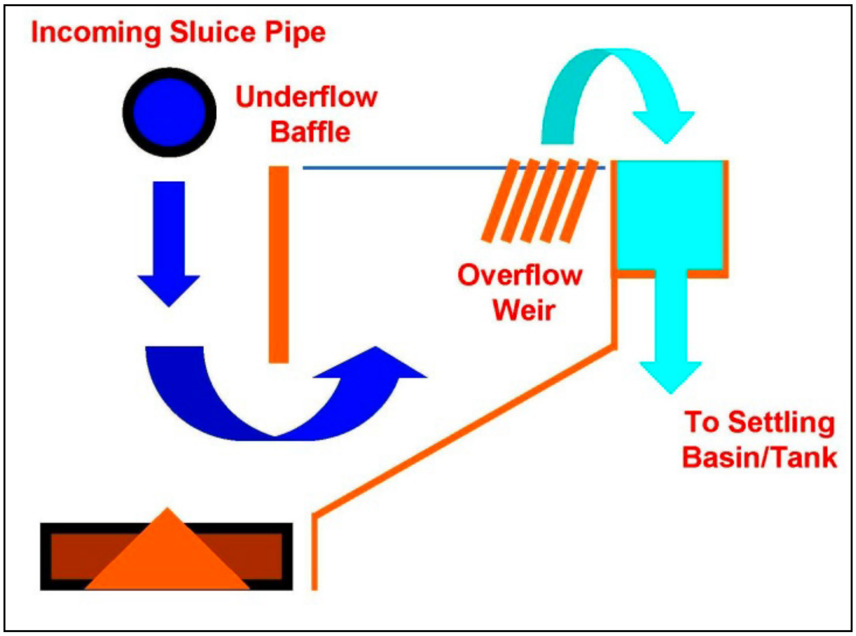


Graphic reprinted with permission from United Conveyor Corporation [McDonough, 2012a].

Figure 7-15. Remote Mechanical Drag System

The plant pumps the bottom ash transport water from the sluice pipes into the trough of the remote mechanical drag system. Similar to dewatering bins (see Section 7.3.9), an underflow baffle prevents the finer particles from exiting the trough with the overflow. As shown in Figure 7-16, the excess transport water in the trough flows over a serrated overflow weir. The plants collect this overflow water in a basin/sump and reuse it in the bottom ash handling system. Because of the chemical properties of bottom ash sluice, some plants may have to install a pH adjustment system to treat the overflow prior to recycle to prevent scaling and fouling in the system. Similar to the mechanical drag system, the drag chain conveys the ash to a collection area and the plant then sells or disposes of it in a landfill.

The settled bottom ash is removed from the trough using the same drag system described in Section 7.3.3. The bottom ash can be loaded directly onto trucks and either sold or transported to a landfill. Remote mechanical drag systems are larger than mechanical drag systems located at the bottom of the boiler, for comparative units, because the remote systems receive excess water that must be separated from the bottom ash. Additionally, the remote mechanical drag systems can service multiple units [Fleming, 2011].



Graphic reprinted with permission from Clyde Bergemann Power Group [CBPG, 2012].

Figure 7-16. Water Flow Inside the Remote Mechanical Drag System Trough

The remote mechanical drag system essentially combines a mechanical drag system and a dewatering bin. However, because the remote mechanical drag system is located away from the boiler and is close to the ground, unlike a traditional dewatering bin, there is little increase in the total dynamic head requirements on the existing pumps and no additional water requirements compared with a traditional wet-sluicing system. Also, because the remote mechanical drag system is not located underneath the boiler and the bottom ash particles have already been through a grinder, these systems require less maintenance than mechanical drag systems [Fleming, 2011]. Unlike the mechanical drag system, remote mechanical drag systems are not located at the bottom of the boiler and, therefore, require water to transport ash to the system. The water associated with the remote mechanical drag system is ash transport water because, like a sluicing system, the water is the transport mechanism that moves the bottom ash away from the hoppers. As such, any excess water that drains off the bottom ash as it is dewatered in an intermediate storage area is considered bottom ash transport water and must meet the zero discharge requirements of the ELGs. In addition, the remote mechanical drag system can be installed nearby while the steam electric generating unit is on line and only takes a few days to tie into the piping to the settling basin/tank. Therefore, this installation or conversion can occur during normal scheduled maintenance outages [CBPG, 2010].

7.3.5 Dry Mechanical Conveyor

Dry mechanical conveyor systems operate similarly to a mechanical drag system, but instead of collecting the bottom ash in a water bath, it is collected directly onto the dry conveyor. The system introduces ambient air countercurrent to the direction of the bottom ash using the negative pressure in the furnace. Introducing additional air activates a reburning process and results in less unburned carbon and additional thermal energy to the steam electric generating process in the boiler, which increases the boiler efficiency. The dry conveyor then conveys the bottom ash to an intermediate storage destination. The plant then sells the ash or disposes of it in a landfill. The modular design of the system allows it to be retrofitted into plants with space or headroom limitations and a wide range of steam electric generating unit capacities (*i.e.*, 5-1000 megawatts (MW)). In addition, the outage required install or convert to a dry mechanical conveyer is about 6 to 8 weeks to demolish existing equipment and install new equipment. Therefore, this installation or conversion can occur during normal scheduled maintenance outages [CBPG, 2010]. Recent advancements related to bottom ash handling technologies, such as the dry mechanical conveyer, have focused on providing more flexible retrofit solutions and improving the thermal efficiency of the boiler operation, which result in additional savings related to electricity use, operation and maintenance, water costs, and thermal energy recovery.

A coal-fired steam electric power plant in Florida retrofitted its existing wet-sluicing systems on its two generating units (greater than 650 MW) with dry mechanical conveyers. The generating units experienced less than 22 days of outages before coming back online in April 2012 and November 2012. After installing the dry mechanical conveyors, the plant has experienced a decrease in power consumption and O&M costs and a reduction in loss-on-ignition in the bottom ash [CBPG, 2013].

7.3.6 <u>Dry Vacuum or Pressure System</u>

Dry vacuum or pressure bottom ash handling systems transport bottom ash from the bottom of the boiler into a dry hopper, without using any water. The system percolates air into the hopper to cool the ash, combust additional unburned carbon, and increase the heat recovery to the boiler. Periodically, the grid doors at the bottom of the hopper open to allow the ash to pass into a crusher that crushes the bottom ash into smaller pieces. The system then conveys the crushed bottom ash by vacuum or pressure to an intermediate storage facility [UCC, 2009]. Figure 7-17 presents a typical dry vacuum or pressure bottom ash handling system.

Dry vacuum or pressure systems eliminate water requirements and improve heat recovery and boiler efficiency. These systems are also less complicated to retrofit to existing generating units because there are less structural limitations (*e.g.*, headspace requirements below the boiler) and the systems can be installed to collect bottom ash from multiple boilers (*e.g.*, one intermediate storage facility for multiple generating units). The plant then sells the ash or disposes of it in a landfill. In addition, the outage required install or convert to dry vacuum or pressure systems is about 6 to 8 weeks. Therefore, this installation or conversion can occur during normal scheduled maintenance outages [UCC, 2011].

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Figure 7-17. Dry Vacuum or Pressure Bottom Ash Handling System

7.3.7 Vibratory Belt System

Vibratory belt systems feed bottom ash by gravity from the bottom of the boiler directly to a vibratory conveyor trough supported by coil springs, which reduce the stress of impact from the falling bottom ash. The vibratory conveyor produces an oscillatory toss-and-catch motion, transporting bottom ash in a series of successive throws. With each throw, the ash moves up and forward onto the conveyor deck. Controlled forced draft air enters through the vibratory conveyor deck to cool, suspend, and enhance oxidation of unburned carbon. The forced draft air surrounds the entire ash surface creating a fluidized bed of ash, which is conveyed to an intermediate storage destination. The plant then sells the ash or disposes of it in a landfill [UCC, 2009]. See Figure 7-18 for the layout of a vibratory bottom ash handling system.

The vibratory system eliminates water requirements and has the lowest power consumption of all other bottom ash handling systems. Additionally, unlike other bottom ash handling systems, the vibratory system does not have any moving or hinged joints that can become damaged from falling boiler slag, decreasing the chance of unscheduled outages for maintenance [UCC, 2009]. However, there are no vibratory belt systems operating in the United States. The outage required to install or convert to dry vacuum or pressure systems is about 6 to 8 weeks. Therefore, this installation or conversion can occur during normal scheduled maintenance outages [UCC, 2011].

Graphic reprinted with permission from United Conveyor Corporation [UCC, 2009].

Figure 7-18. Vibratory Bottom Ash Handling System

7.3.8 Mechanical System

Similar to fly ash handling systems, mechanical bottom ash handling systems usually service generating units that generate low volumes of bottom ash, or handle fly and bottom ash together. These units are usually oil-fired generating units, which typically produce less ash than coal-fired generating units. Mechanical systems include any manual or systematic approach to removing bottom ash. Based on responses to the Steam Electric Survey, the systems can include periodic scheduled boiler cleanings or manual ash removal. Both procedures involve scraping the sides of the boilers with sprayers or shovels, then collecting and removing the bottom ash to an intermediate storage destination. Some plants store the collected ash in an ash impoundment, while others sell or dispose of the ash in a landfill.

7.3.9 Complete Recycle System

Complete recycle bottom ash systems transport bottom ash via water, using the same process as wet-sluicing systems, but all the water that leaves the system is recycled back to the bottom of the boiler and/or used as make-up to the bottom ash sluicing system. Because the bottom ash is hot and evaporates a portion of the water in the quench bath, the bottom ash sluicing system is a net consumer of water, which allows the system to completely reuse all the water along with a make-up stream. The complete recycle system can operate using several different configurations. The most common configuration in the industry is to operate with dewatering bins (described in Section 7.3.1) with the overflow pumped to an impoundment and the overflow from the impoundment being pumped back to the bottom ash sluice system. There are also several other configurations that achieve complete recycle using tank-based systems that do not include impoundments. These tank-based systems can either use dewatering bins or a remote mechanical drag system. For a dewatering bin complete recycle system, the overflow and decant are transferred to additional settling tanks prior to being recycled back to the bottom ash sluice system, as shown in Figure 7-13. In the settling tank, a large percentage of the fine ash carryover settles to the bottom and is pumped to the dewatering bin for removal. The plant directs the overflow from the settling tank to the surge tank, where recirculation pumps return the water to the existing bottom ash handling system or as makeup water to the quench water bath. For a remote mechanical drag system complete recycle system, the overflow water is collected in a sump prior to being recycled back to the bottom ash sluice system. Fine ash that carries over into the sump will collect at the bottom of the sump and the plant will need to collect this material occasionally and dispose of it off site or in a landfill.

Some complete-recycle systems may need to add treatment chemicals, specifically for pH control, to the overflow/decant water to eliminate any scaling or fouling caused by the recycled water.

Plants that install complete-recycle systems on existing wet-sluicing generating units can reuse all of the existing wet-sluicing equipment. These systems also allow plants to handle bottom ash from multiple boilers. However, because of the amount of equipment and water these systems use, complete-recycle systems have the highest equipment, maintenance, and power consumption requirements of all other bottom ash handling systems.

Alternatively, plants use impoundment systems to achieve complete recycle. Some plants discharge the ash to an impoundment, or series of impoundments, to settle and then return all impoundment, or impoundment system, effluent to the boiler to use as transport water. These plants often add additional makeup water to the system to compensate for any water lost due to evaporation or water retained in the ash. In addition, closed recirculation systems can be built while the steam electric generating unit is on line and would not take more than a few days to tie into the system. Therefore, this installation or conversion can occur during normal scheduled maintenance outages [UCC, 2011].

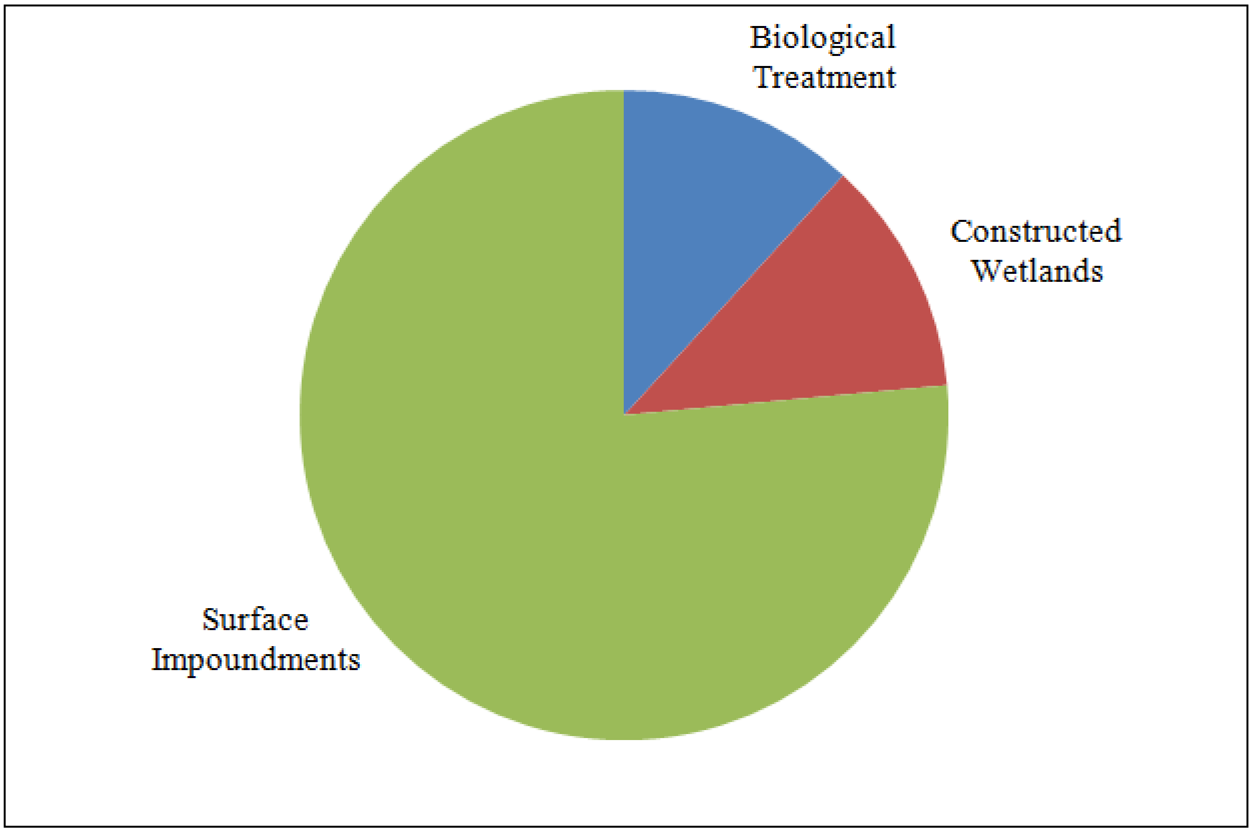
7.4 COMBUSTION RESIDUAL LEACHATE

During the rulemaking, EPA identified and investigated wastewater treatment systems and management practices in use by steam electric power plants to treat leachate collected from landfills and impoundments containing combustion residuals. From industry profile information and leachate characterization data, described in Sections 4.3.5 and 6.3, EPA determined that combustion residual leachate from landfills and impoundments includes similar types of constituents as FGD wastewater, although the concentrations of the constituents in combustion residual leachate are generally lower than in FGD wastewater. Based on this characterization of the wastewater and knowledge of treatment technologies, EPA determined that certain treatment technologies identified for FGD wastewater could also be used to treat leachate from landfills and impoundments containing combustion residuals.

Additionally, EPA used information from the Steam Electric Survey, site visits, and industry profile to identify wastewater treatment systems and management practices currently used, or considered, to treat and manage combustion residual landfill and impoundment leachate. The wastewater treatment technologies that EPA identified to treat combustion residual leachate include:

- Surface impoundments.
- Chemical precipitation.
- Biological treatment (anoxic/anaerobic system with fixed-film bioreactors).
- Constructed wetlands.

In the Steam Electric Survey, EPA requested a subset of coal-fired power plants to provide information on combustion residual leachate treatment systems and management practices used in the industry. From the treatment system information received, EPA determined that surface impoundments are the most commonly used system to treat combustion residual leachate from landfills and impoundments [ERG, 2015a]. Figure 7-19 shows the distribution of combustion residual leachate treatment technologies reported in the Steam Electric Survey or determined by EPA through industry contacts for the 17 plants that reported treatment systems for combustion residual landfill and impoundment leachate.



Source: Steam Electric Survey [ERG, 2015a; WVDEP, 2010].

Note: This figure represents the EPA population used in analyses for the ELGs, which was developed using the weighted Steam Electric Survey data (see Section 4.2.4), industry profile changes (see Section 4.5), and additional industry-provided information.

Figure 7-19. Distribution of Treatment Systems for Leachate from Landfills and Impoundments Containing Combustion Residual Wastes

Additionally, EPA investigated the management practices for combustion residual leachate from landfills and impoundments. From information in the Steam Electric Survey, EPA determined that 14 plants collect their combustion residual landfill leachate and use it as water for moisture conditioning dry fly ash prior to disposal or dust control around dry unloading areas and landfills. EPA also identified five plants that use the collected leachate as truck wash and route it back to an impoundment.

EPA also identified from the Steam Electric Survey approximately 40 percent of plants that collect combustion residual impoundment leachate and recycle it directly back to the impoundment from which it was collected. In this case, because the wastewater originated from the impoundment, and the collection system is essentially just capturing and returning a portion of the impoundment wastewater, EPA does not consider the wastewater recycled directly back to the impoundment as a new wastestream entering the impoundment. Instead, EPA considers it to be the same as the wastewater that is already contained within the impoundment system. However, if any of this collected wastewater is transferred to any other process or operation and discharged, then it would be considered combustion residual leachate and must comply with the applicable limitations established by the ELGs. EPA determined that six plants collect combustion residual leachate from the impoundment and use it as water for moisture conditioning dry fly ash prior to disposal or dust control around dry unloading areas and landfills. EPA also identified four additional plants that use combustion residual leachate for moisture conditioning fly ash and/or dust control; however, EPA was unable to determine if the wastewater originated from a landfill or impoundment.

7.5 Flue Gas Mercury Control Wastewater Treatment Technologies

During the rulemaking, EPA identified and investigated wastewater treatment systems operated by steam electric power plants to treat wastewater generated from FGMC, as well as operating/management practices used to reduce the wastewater discharge. As described in Section 4.3.4, these systems are relatively new to the industry.

Generally, there are two types of FGMC systems: addition of oxidizing agents to the coal prior to combustion and injection of activated carbon (or other sorption material) into the flue gas upstream or downstream of the primary particulate control system. FGMC systems that add oxidizers simply collect the oxidized mercury with the wet FGD system. This does not generate a new wastewater stream; however, it may increase the concentration of mercury in the FGD wastewater because the oxidized mercury is more easily removed by the FGD system.

In activated carbon injection (ACI) systems, the steam electric power plant injects activated carbon either before or after primary particulate control. If activated carbon is injected prior to the primary particulate control system, the adsorbed mercury is collected with the fly ash and handled according to the technologies described in Section 7.2, including wet sluicing. However, if the activated carbon is injected after the primary particulate control system, the plant must install a different handling system to handle the FGMC waste. Similar to Section 7.2, these systems include:

FGMC Systems that Generate FGMC Wastewater

- *Wet-Sluicing System:* These systems use water-powered hydraulic vacuums to create the vacuum for the initial withdrawal of FGMC waste from the hoppers. The FGMC waste is combined with the water used to create the vacuum and then pumped to an ash impoundment.

FGMC Systems that Do Not Generate FGMC Wastewater

- *Wet Vacuum Pneumatic System*: These systems use water-powered hydraulic vacuums to create the vacuum for the initial withdrawal of FGMC waste from the hoppers, similar to wet-sluicing systems; however, the FGMC waste is directed to a silo and is not combined with the water flowing through the sluice pipes.
- *Dry Vacuum System*: These systems use a mechanical exhauster to move air, below atmospheric pressure, to pull the FGMC waste from the hoppers and convey it directly to a silo.
- *Pressure System*: These systems use air produced by a positive displacement blower to convey the FGMC waste directly from the hopper to a silo.
- *Combined Vacuum/Pressure System*: These systems first utilize a dry vacuum system to pull FGMC waste from the hoppers to a transfer station and then use a positive displacement blower to convey the FGMC waste to a silo.

Based on responses to the Steam Electric Survey, EPA identified 62 power plants that operate ACI systems. Twelve of these plants inject the activated carbon downstream of the primary particulate removal system and the remaining 50 plants inject the activated carbon upstream of the particulate removal system [ERG, 2015a]. The following describes how these plants handle their FGMC wastes:

- Of the downstream ACI systems, only one plant handles the FGMC waste wet. The plant identified a planned FGMC system and indicated that the waste will be sluiced to a zero discharge impoundment from which solids are landfilled and wastewater is recycled within the plant.
- The remaining 11 downstream ACI systems handle the FGMC waste dry.
- Of the upstream ACI systems, three plants handle the FGMC waste wet. These plants indicated that the waste will be wet sluiced to an impoundment from which solids are landfilled and wastewater is potentially discharged[52]
- The remaining 47 upstream ACI systems handle the FGMC waste dry.

7.6 GASIFICATION WASTEWATER TREATMENT TECHNOLOGIES

During the rulemaking, EPA identified and investigated wastewater treatment systems operated by steam electric power plants to treat wastewater generated at integrated gasification combined cycle (IGCC) plants from the gasification process, as well as operating/management practices used to reduce the wastewater discharge. This section describes the following technologies:

[52] Two of these plants do not discharge any FGMC wastewater. The one plant that does discharge the FGMC wastewater also has the capability to handle its fly ash and FGMC waste using a dry system.

- Evaporation system.
- Cyanide destruction.

EPA is aware of three plants that currently operate IGCC units in the United States.[53] All three of these plants currently treat the gasification wastewaters with evaporation systems. One of these plants installed a cyanide destruction system in addition to an evaporation system.

7.6.1 Evaporation System

As described in Section 7.1.4, plants can use evaporation systems to treat FGD wastewater and cooling tower blowdown. Additionally, the plants currently operating IGCC units are using evaporation systems to treat the gasification wastewaters generated. The treatment system design is the same as that described for treating FGD wastewater, as discussed in Section 7.1.4; however, unlike the system used to treat FGD wastewater, the gasification wastewater does not require the pretreatment chemical precipitation and softening steps.

This evaporation system uses a falling-film evaporator (or brine concentrator) to produce a concentrated wastewater stream and a distillate stream. The concentrated wastewater stream may be further processed in a crystallizer, spray dryer, or rotary drum dryer, in which the remaining water is evaporated, generating a solid waste product and potentially a condensate stream. The plant can reuse the distillate and condensate streams or discharge them to surface waters. Figure 7-5 presents a process flow diagram for an evaporation system.

7.6.2 Cyanide Destruction

Because the wastewaters from the IGCC process can contain different cyanide contaminants (*e.g.*, selenocyanate) formed in the gasification unit, one steam electric power plant installed a cyanide destruction system to treat both the distillate and condensate effluent streams from the evaporation system. Cyanide destruction treatment involves adding sodium hypochlorite (*i.e.*, bleach) to the wastewater in mixing tanks and providing enough residence time for the bleach to completely react with the cyanide present.

7.7 References

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[53] EPA is also aware of the Kemper County Energy Facility that will include an IGCC unit. According the operating company's website, the plant will not discharge any gasification wastewater and, therefore, will not incur any costs to comply with the ELGs.

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SECTION 8
THE FINAL RULE

This section describes the final rule, including the technology bases and rationale for the effluent limitations guidelines and standards (ELGs), for the Steam Electric Power Generating Point Source Category. This section describes the revisions to the following limitations and standards:

- Best Practicable Control Technology Currently Available (BPT).
- Best Available Technology Economically Achievable (BAT).
- New Source Performance Standards (NSPS).
- Pretreatment Standards for Existing Sources (PSES).
- Pretreatment Standards for New Sources (PSNS).

The technology options selected as the basis for the final rule incorporate pollutant control technologies that are demonstrated in the steam electric power generating industry, minimize water use, and result in minimal non-water quality environmental impacts. While EPA establishes limitations and standards based on a particular set of in-process and end-of-pipe treatment technology options, EPA does not require a discharger to use these technologies. Rather, the technologies that may be used to treat wastewater are left entirely to the discretion of the individual plant operator, as long as the plant can achieve the numerical discharge limitations and standards, as required by Section §301(b) of the Clean Water Act (CWA). Direct and indirect dischargers can use any combination of process modifications, in-process technologies, and end-of-pipe wastewater treatment technologies to achieve the ELGs.

EPA selected the technology bases for the final rule for each wastestream from the technologies described in Section 7. Section 8.1 describes the existing BPT/BCT requirements. Section 8.2 describes the regulatory options and underlying technology bases evaluated for BAT, NSPS, PSES, and PSNS. Sections 8.3 through 8.6 discuss the rationale for the selected technology bases for BAT, NSPS, PSES, and PSNS, respectively. Sections 8.7 through 8.10 discuss other elements of the final rule, including anticircumvention provisions, applicability clarification, non-chemical metal cleaning waste, and best management practices (BMPs).

8.1 BPT

The final rule does not revise the previously established best practicable control technology currently available (BPT) effluent limitations because the rule regulates the same wastestreams at the more stringent BAT/NSPS level of control. The rule does, however, make certain structural modifications to the BPT regulations in light of new and revised definitions. In particular, the final rule establishes separate definitions for FGD wastewater, FGMC wastewater, gasification wastewater, and combustion residual leachate, making clear that these four wastestreams are no longer considered low volume waste sources. Given these new and revised definitions, the final rule modifies the structure of the previously established BPT regulations so that they specifically identify these four wastestreams, but without changing their applicable BPT limitations, which are equal to those for low volume waste sources.

8.2 DESCRIPTION OF THE BAT/NSPS/PSES/PSNS OPTIONS

EPA analyzed many regulatory options at proposal, the details of which were discussed fully in the document published on June 7, 2013 (78 FR 34432). EPA proposed to regulate pollutants found in seven wastestreams found at steam electric power plants, each based on particular control technologies. Depending on the interests represented, public commenters supported virtually all of the regulatory options that EPA proposed – from the least stringent to the most stringent, and many options in between. For this final rule, based on public comments, EPA also considered a few additional regulatory options. None of these additional regulatory options involve regulation of different control technologies than those explicitly considered and presented at proposal. Rather, they involve slight variations on the overall packaging of the key options presented at proposal. Thus, in developing this final rule, EPA named six main regulatory options, Options A, B, C, D, E, and F.[54] Table 8-1 summarizes these six regulatory options. In general, as one moves from Option A to Option F, there is a greater estimated reduction in pollutant discharges from steam electric power plants and a higher associated cost.

Consistent with the proposed rule, under all Options A through F, for oil-fired generating units and small generating units (50 megawatts (MW) or smaller) that are existing sources, the rule would establish BAT/PSES effluent limitations and standards on TSS in fly ash transport water, bottom ash transport water, FGD wastewater, FGMC wastewater, combustion residual leachate, and gasification wastewater equal to the previously promulgated BPT effluent limitations on TSS[55] in fly ash transport water, bottom ash transport water, and low volume waste sources, where applicable. Under Options A through E, EPA would establish a voluntary incentives program for plants that choose to meet BAT limitations for FGD wastewater based on evaporation technology. Moreover, as EPA proposed, under Options A through F, the ELG would establish an anti-circumvention provision designed to ensure that the purpose of the rule is achieved, as further described in Section 8.7. Finally, as EPA proposed, under all Options A through F, the ELG would correct a typographical error in the previously promulgated regulations, as well as make certain clarifying revisions to the applicability provision of the regulations, as further described in Section 8.8.

Sections 8.2.1 through 8.2.7 describe Options A through F, by wastestream, including the technology bases for the requirements associated with each.

[54] Option B is equivalent to Proposed Option 3, Option C is equivalent to Proposed Option 4a, and Option E is equivalent to Proposed Option 4 and Option F is equivalent to Proposed Option 5. Option A is a slight variant of Proposed Options 1 and 3 and Option D is a slight variant of Proposed Option 4.

[55] Although TSS is a conventional pollutant, whenever EPA would be regulating TSS in this final rule, it would be regulating it as an indicator pollutant for the particulate form of toxic metals.

Table 8-1. Steam Electric Power Generating Point Source Category Regulatory Options

Wastestreams	Technology Basis for BAT/NSPS/PSES/PSNS Regulatory Options					
	A	**B**	**C**	**D**	**E**	**F**
FGD Wastewater	Chemical Precipitation	Chemical Precipitation + Biological Treatment	Chemical Precipitation + Biological Treatment	Chemical Precipitation + Biological Treatment	Chemical Precipitation + Biological Treatment	Evaporation
Fly Ash Transport Water	Dry Handling	Dry Handling	Dry handling	Dry handling	Dry handling	Dry handling
Bottom Ash Transport Water	Impoundment (Equal to BPT)	Impoundment (Equal to BPT)	Dry handling/Closed loop (for units >400 MW); Impoundment (Equal to BPT)(for units ≤400 MW)	Dry handling/ Closed loop	Dry handling/ Closed loop	Dry handling/ Closed loop
FGMC Wastewater	Dry handling	Dry handling	Dry handling	Dry handling	Dry handling	Dry handling
Gasification Wastewater	Evaporation	Evaporation	Evaporation	Evaporation	Evaporation	Evaporation
Combustion Residual Leachate	Impoundment (Equal to BPT)	Impoundment (Equal to BPT)	Impoundment (Equal to BPT)	Impoundment (Equal to BPT)	Chemical Precipitation	Chemical Precipitation
Non-Chemical Metal Cleaning Wastes	[Reserved]	[Reserved]	[Reserved]	[Reserved]	[Reserved]	[Reserved]

8.2.1 FGD Wastewater

Under Option A, EPA would establish effluent limitations and standards for mercury and arsenic in FGD wastewater based on treatment using chemical precipitation. As used in the regulatory options for this rulemaking, this technology is a combination of hydroxide precipitation, iron coprecipitation, and sulfide precipitation to remove heavy metals. Under Options B through E, EPA would establish effluent limitations and standards for mercury, arsenic, selenium, and nitrate-nitrite as N in FGD wastewater based on treatment using chemical precipitation followed by biological treatment. For the regulatory options, biological treatment refers to an anoxic/anaerobic fixed-film biological system optimized to remove selenium from the wastewater. Part of the technology basis under Options A through E would also include the use of flow minimization for plants with high FGD discharge flow rates (greater than 1,000 gpm).[56] Under Option F, EPA would establish effluent limitations and standards for mercury, arsenic, selenium, and TDS in FGD wastewater based on treatment using an evaporation system. Under all options, to facilitate implementation of the new BAT/NSPS/PSES/PSNS requirements, EPA would also promulgate a definition for FGD wastewater, making clear it would no longer be considered a low volume waste source.

8.2.2 Fly Ash Transport Water

Under all Options A through F, EPA would establish (or in the case of NSPS/PSNS, maintain) zero discharge effluent limitations and standards for pollutants in fly ash transport water based on use of a dry handling system. For the regulatory options, a dry handling system refers to a dry vacuum system that uses a mechanical exhauster to move air, below atmospheric pressure, to pull the fly ash from the hoppers and convey it directly to a silo. Fly ash dry handling technologies are described in more detail in Section 7.

8.2.3 Bottom Ash Transport Water

Under Options A and B, EPA would establish effluent limitations and standards for bottom ash transport water equal to the previously promulgated BPT limitation on TSS,[57] which is based on the use of a surface impoundment. Under Options D, E, and F, EPA would establish zero discharge effluent limitations and standards for pollutants in bottom ash transport water based on one of two technologies: a dry handling system or a closed-loop system. EPA evaluated two different technology bases for bottom ash because not all plants will be able to install a dry handling system due to space constraints at the boiler. For the dry handling system, EPA evaluated a mechanical drag system, where the bottom ash collects in a water quench bath and a drag chain conveyor pulls the bottom ash out of the water bath on an incline to dewater the bottom ash. For the closed-loop system, EPA evaluated a remote mechanical drag system, where the bottom ash is transported using the same processes as a wet-sluicing system. However, instead of transporting the bottom ash to an impoundment, the ash is sluiced to a remote mechanical drag system, where a drag chain conveyor pulls the bottom ash out of the water on an

[56] Only for those high-flow plants where the metallurgy of the FGD system can accommodate higher chloride concentrations that would result from flow minimization.

[57] Although TSS is a conventional pollutant, whenever EPA would be regulating TSS in this final rule using BAT, it would be regulating it as an indicator pollutant for the particulate form of metals.

incline to dewater it. The transport (sluice) water is treated to remove solids in a settling tank and is recycled to the bottom ash collection system. Both mechanical drag and remote mechanical drag systems are described in more detail in Section 7. Under Option C, EPA would establish, for bottom ash transport water, zero discharge limitations and standards based on dry handling or closed-loop systems only for generating units with a nameplate capacity of more than 400 MW. Units with a nameplate capacity equal to or less than 400 MW would have to meet new effluent limitations and standards equal to the previously established BPT limitation on TSS, based on surface impoundments.

8.2.4 FGMC Wastewater

Under all Options A through F, EPA would establish zero discharge effluent limitations and standards for FGMC wastewater based use of a dry handling system. For the regulatory options, dry handling system refers to a dry vacuum system that uses a mechanical exhauster to move air, below atmospheric pressure, to pull the FGMC waste from the hoppers and convey it directly to a silo. Dry handling systems are described in more detail in Section 7. The previously established regulations included FGMC wastewater within the definition of low volume waste sources, which is subject to BPT limitations for TSS and oil and grease (based on surface impoundments). Under all Options A through F, EPA would establish a separate definition for FGMC wastewater, making clear it would no longer be considered a low volume waste source.

8.2.5 Gasification Wastewater

The technology basis for control of gasification wastewater under all Options A through F is an evaporation system. Under these options, EPA would establish limitations and standards on arsenic, mercury, selenium, and total dissolved solids (TDS) in gasification wastewater. For the regulatory options, evaporation refers to a system using a falling-film evaporator (also referred to as a brine concentrator) to produce a concentrated wastewater stream (*i.e.*, brine) and a reusable distillate stream. Evaporation systems are described in more detail in Section 7. As with FGMC wastewater, the previously established regulations included gasification wastewater within the definition of low volume waste sources, which is subject to BPT limitations on TSS and oil and grease, based on surface impoundments. Under all Options A through F, EPA would establish a separate definition for gasification wastewater, making clear it would no longer be considered a low volume waste source.

8.2.6 Combustion Residual Leachate from Surface Impoundments and Landfills Containing Combustion Residuals

Under Options A through D, EPA would establish effluent limitations and standards for combustion residual leachate from surface impoundments and landfills containing combustion residuals equal to the previously promulgated BPT effluent limitation on TSS[58] for low volume waste sources. Under Options E and F, EPA would establish limitations and standards on arsenic and mercury in combustion residual leachate based on treatment using a chemical precipitation system (the same technology basis described for control of FGD wastewater under Option A).

[58] Although TSS is a conventional pollutant, whenever EPA would be regulating TSS in this final rule, it would be regulating it as an indicator pollutant for the particulate form of toxic metals.

See Section 7 for a discussion of these technologies. As with FGMC and gasification wastewater, the previously established regulations included combustion residual leachate within the definition of low volume waste sources, which is subject to BPT limitations on TSS and oil and grease. Under all Options A through F, EPA would establish a separate definition for combustion residual leachate, making clear it would no longer be considered a low volume waste source.

8.2.7 Non-Chemical Metal Cleaning Wastes

Under all Options A through F, EPA would continue to reserve BAT/NSPS/PSES/PSNS for non-chemical metal cleaning wastes, as the previously established regulations do.

8.3 Best Available Technology Economically Achievable

After considering the technologies described in Section 7, as well as public comments, and in light of the factors specified in CWA sections 304(b)(2)(B) and 301(b)(2)(A), EPA decided to establish BAT effluent limitations based on the technologies described in Option D. Thus, for BAT, the final rule establishes:

- Limitations on arsenic, mercury, selenium, and nitrate-nitrite as N in FGD wastewater, based on chemical precipitation plus biological treatment.[59]
- A zero discharge limitation for pollutants in fly ash transport water, based on dry handling.
- A zero discharge limitation for pollutants in bottom ash transport water, based on dry handling/closed-loop systems.
- A zero discharge standard for FGMC wastewater, based on dry handling.
- Limitations on mercury, arsenic, selenium, and TDS in gasification wastewater, based on evaporation. [60]
- A limitation on TSS in combustion residual leachate based on surface impoundments.[61]

The final rule also establishes new definitions for FGD wastewater, FGMC wastewater, gasification wastewater, and combustion residual leachate.

Sections 8.3.1 through 8.3.6 provide more detail on the Option D technologies for each wastestream.

[59] For those plants that choose to participate in the voluntary incentives program, the applicable limitations are for arsenic, mercury, selenium, and TDS in FGD wastewater, based on the use of an evaporation system (see Section 8.3.13).

[60] For small (50 MW or less) generating units and oil-fired generating units, the final rule establishes different BAT limitations for FGD wastewater, fly ash transport water, bottom ash transport water, FGMC wastewater, and gasification wastewater (see Section 8.3.12).

[61] The final rule also establishes BAT limitations on TSS in discharges of "legacy wastewater," which are equal to previously established TSS limitations (see Section 8.3.8).

8.3.1 FGD Wastewater

This rule identifies treatment using chemical precipitation followed by biological treatment as the BAT technology basis for control of pollutants discharged in FGD wastewater. More specifically, the technology basis for BAT is a chemical precipitation system that employs hydroxide precipitation, sulfide precipitation (organosulfide), and iron coprecipitation, followed by an anoxic/anaerobic fixed-film biological treatment system designed to remove heavy metals, selenium, and nitrates.[62] After accounting for industry changes described in Section 4.5, forty-five percent 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.[63] Many of these plants use FGD wastewater management approaches that eliminate the discharge of FGD wastewater.[64] Other plants employ wastewater treatment technologies that reduce the amount of pollutants in the FGD wastestream.

Both chemical precipitation and biological treatment are well-demonstrated technologies that are available to steam electric power plants for use in treating FGD wastewater. Based on responses to the *Questionnaire for the Steam Electric Power Generating Effluent Guidelines* (Steam Electric Survey), 39 U.S. steam electric power plants (44 percent of plants discharging FGD wastewater) use some form of chemical precipitation as part of their FGD wastewater treatment system. More than half of these plants (30 percent of plants discharging FGD wastewater) use both hydroxide and sulfide precipitation in the process to further reduce metals concentrations. In addition, for the last several decades, thousands of industrial facilities nationwide such as Metal Products and Machinery facilities, Iron & Steel manufacturers, metal finishers, and mining operations (including coal mines) have used chemical precipitation (see Section 7) [U.S. EPA, 2003; U.S. EPA, 2002; U.S. EPA, 1983].[65]

The biological treatment system that forms part of the basis for BAT in the ELG is optimized to remove selenium from the wastewater. The information in the record demonstrates that the amount of mercury and other pollutants removed by the biological treatment stage of the treatment system, above and beyond the amount of pollutants removed in the chemical

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[62] In estimating costs associated with this technology basis, EPA assumed that in order to meet the limitations and standards, certain plants with high FGD discharge flow rates (greater than or equal to 1,000 gpm) would elect to incorporate flow minimization into their operating practices (by reducing the FGD purge rate or recycling a portion of their FGD wastewater back to the FGD system), where the FGD system metallurgy can accommodate an increase in chlorides. See Section 4.5.4 of EPA's *Incremental Costs and Pollutant Removals for the Final Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* [U.S. EPA, 2015a].

[63] This value accounts for announced retirements, conversions, and changes plants are projected to make to comply with the CPP and CCR rules.

[64] A variety of approaches that depend on plant specific conditions are used to achieve zero pollutant discharge at these plants, including evaporation ponds, complete recycle, and processes that combine the FGD wastewater with other materials for landfill disposal. Although these technologies, as well as others currently used for achieve zero pollutant discharge, may be available for some plants with FGD wastewater, EPA determined they are not available nationally. For example, evaporation ponds are only available in certain climates. Similarly, complete recycle is only available at plants with appropriate FGD metallurgy.

[65] Physical/chemical treatment systems can be effective at removing mercury and certain other metals; however, to achieve effective removal of selenium this technology must be coupled with additional treatment technology such as anoxic/anaerobic biological treatment.

precipitation treatment stage preceding the bioreactor, can be substantial. In addition, the anoxic conditions in the bioreactor can remove substantial concentrations of nitrates by denitrification. FGD wastewater containing exceptionally high levels of nitrates (*e.g.*, greater than 100 parts per million (ppm) nitrate/nitrite (as N)) can be pretreated using standard denitrification technologies such as membrane bioreactors or stirred-tank bioreactors. If necessary, the biological processes can also be modified to include a step to nitrify and remove ammonia.

Biological treatment has been tested at steam electric power plants for more than ten years and full-scale systems have been operating at a subset of plants for seven years. It has been widely used in many industrial applications for decades in both the U.S. and abroad and it has been employed at coal mines. Currently, six U.S. steam electric power plants (approximately ten percent of those discharging FGD wastewater) use biological treatment designed to substantially reduce nitrogen compounds and selenium in their FGD wastewater. Other power plants are considering installing biological treatment to remove selenium, and at least one plant is scheduled to begin operating a biological treatment system for selenium removal next year [GE, 2015]. An additional two plants are installing a similar treatment system to remove selenium in discharges of combustion residual leachate [ERG, 2015a]. Four of the six plants using biological systems to treat FGD wastewater precede the biological treatment stage with chemical precipitation; thus, the entire system is designed to remove suspended solids, particulate and dissolved metals (such as mercury and arsenic), soluble and insoluble forms of selenium, and nitrate and nitrite forms of nitrogen. These plants show that chemical precipitation followed by biological treatment is technologically available and demonstrated. The other two plants operating anoxic/anaerobic bioreactors to remove selenium precede the biological treatment stage with surface impoundments instead of chemical precipitation. The treatment systems at these two plants are likely to be less effective at removing metals (including many dissolved metals) and would likely face more operational problems than the plants employing chemical pretreatment, but they nevertheless show the efficacy and availability of biological treatment for removing selenium and nitrate/nitrite in FGD wastewater. Finally, vendors continue to make improvements to these systems and to develop non-biological systems for selenium removal.

BAT for FGD wastewater also incorporates flow minimization for certain plants with high FGD discharge flow rates (greater than 1,000 gpm). Plants may choose to minimize their flows by either reducing the FGD purge rate or recycling a portion of their FGD wastewater back to the FGD system.

A few commenters questioned the feasibility of biological treatment at some power plants. Specifically, they claimed, in part, that the efficacy of biological systems is unpredictable and is subject to temperature changes, high chloride concentrations, scaling, and high oxidation-reduction potential (ORP) in the absorber, which could kill the microorganisms in the bioreactor. EPA’s record does not support these assertions for a well-designed and well-operated chemical precipitation and biological treatment system.

EPA’s record demonstrates that proper pretreatment prior to biological treatment and proper monitoring with adjustments to the treatment system as necessary are key to reducing operational concerns raised by commenters. Proper pretreatment includes chemical precipitation, which can address wastewater containing high oxidant loadings through addition of a reducing agent in one of the treatment system's reaction tanks.[66] EPA included capital costs for a chemical addition system and hopper for a reducing agent in its cost estimates for the BAT limitations based on chemical precipitation plus biological treatment. The dose of reducing agent can be determined in real time based on a combination of pH and ORP measurements of the feed to the chemical precipitation system. System operators may wish to conduct testing to correlate pH and ORP with the necessary dosage of reducing agent. Alternatively, operators could use a simple titration to determine Total Oxidant Load (*e.g.*, iodometric titration) to determine the amount of reducing agent that must be added to remove any oxidant load. The reaction between any oxidant in the wastewater and the reducing agent is very fast and would not require a separate mixing tank. Additionally, EPA recommends that plants evaluate the operation of their FGD scrubbers to understand what conditions lead to high oxidant excursions and optimize the operation of the scrubber with respect to wastewater treatment. Recent pilot studies of biological treatment systems for FGD wastewater treatment demonstrate that monitoring ORP, pH, and total oxidant loading is essential for proper operation of these systems and have shown that these strategies can be used to address the issue of high oxidant load in FGD wastewater [ERG, 2015b]. Monitoring these parameters enables the plant to adjust the system as necessary. For example, plants that monitor ORP in the absorber or in the FGD purge will have sufficient advanced warning to respond to elevated ORP levels by adding a chemical reductant to the chemical precipitation system and/or increasing the feed rate of the nutrient mix in the biological reactor. EPA's cost estimates account for all of these monitoring steps.

Plants can also use the chemical precipitation system to minimize scaling on downstream equipment. FGD wastewater leaving the hydroclones may be saturated or potentially supersaturated with calcium sulfate, which could cause significant scaling if calcium sulfate deposits form in piping or other surfaces of the FGD wastewater treatment system. A well-designed and well-operated chemical/physical precipitation system has enough residence time and optimized chemical conditions to precipitate much of the calcium sulfate as solid particles and then remove them in the clarifier.

Although chemical precipitation systems are typically not able to remove chlorides from FGD wastewater, EPA's record demonstrates that the anaerobic bioreactor systems can handle chloride levels of up to 30,000 ppm [GE, 2014a]. Careful system design can account for this constraint by adjusting the amount of flow minimization used in the FGD scrubber and the size of the treatment system itself.

FGD wastewater containing exceptionally high levels of nitrates (*e.g.*, greater than 100 ppm nitrate/nitrite as N) can be pretreated using standard denitrification technologies such as membrane bioreactors or stirred-tank bioreactors. If necessary, the biological processes can also be modified to include a step to nitrify and remove ammonia. EPA's cost estimates account for this pretreatment step. EPA's record, moreover, shows that the treatment systems that form the bases for the BAT limitations for FGD wastewater are able to effectively remove the regulated pollutants at varying influent concentrations [U.S. EPA, 2015b]. Finally, vendors continue to make improvements to these systems and to develop non-biological systems for selenium

[66] EPA included the equipment for chemical addition of a reducing agent in its cost estimates for Options B through E.

removal. Additional information on strategies to address potential operational concerns are included in EPA's communications with the vendor [GE, 2014a; GE, 2014b].

Some commenters also claimed that the efficacy of biological systems in removing selenium is subject to changes in switching from one coal type to another (also referred to as fuel flexing). Where EPA had biological treatment performance data paired with fuel type, EPA reviewed it and found that existing biological treatment systems continue to perform well during periods of fuel switching [ERG, 2015c]. The data show that, in all cases except one, the plants met the selenium limitations following fuel switches. In one instance when a plant switched to a certain coal type, the plant exceeded the final daily maximum selenium limitation for one out of thirteen observations for the month while the average of all values for that month were below the final monthly selenium limitation. While the data demonstrate that one plant did, at times, experience elevated selenium effluent concentrations when it switched to a certain coal type, it also showed that there were no changes in selenium effluent concentrations at several other times when the plant switched coals. This plant was not subject to a selenium limit at the time data was collected. Moreover, EPA's record demonstrates that effective communication between the operator(s) of the generating unit and the boiler, as well as bench testing and monitoring the ORP, and making proper adjustments to the operation of the treatment system, would make it possible to prevent potential selenium exceedances at this plant. Data for two other plants operating full-scale biological treatment systems shows that fuel switches should not result in exceeding the effluent limitations. EPA also has data from a pilot project at another plant employing the same type of coal used by the one plant that experienced elevated selenium effluent concentrations following a coal switch. The data for this pilot project demonstrate effective selenium removal by the BAT technology basis, with all effluent values at concentrations below the BAT limitations established in this rule.

EPA also reviewed effluent data in the record for plants operating combined chemical precipitation and biological treatment for FGD wastewater to evaluate how cycling operation (i.e., changes in electricity generation rate) and short or extended shutdown periods may affect the ability of plants to meet the BAT effluent limitations. These data demonstrate that cycling operations and shutdown periods, whether short or long in duration, are manageable and do not result in plants being unable to meet the ELG effluent limitations [ERG, 2015c].

EPA did not select surface impoundments as the technology basis for BAT for FGD wastewater because it would not result in reasonable further progress toward eliminating the discharge of all pollutants, particularly toxic pollutants (see CWA section 301(b)(2)(A)). Surface impoundments, which rely on gravity to remove particulates from wastewater, are the technology basis for the previously promulgated BPT effluent limitations for low volume waste sources. Pollutants that are present mostly in soluble (dissolved) form, such as selenium, boron, and magnesium, are not effectively and reliably removed by gravity in surface impoundments. For metals present in both soluble and particulate forms, such as mercury, gravity settling in surface impoundments does not effectively remove the dissolved fraction. Furthermore, the environment in some surface impoundments can create chemical conditions (*e.g.*, low pH) that convert particulate forms of metals to soluble forms, which are not removed by the gravity settling process. Additionally, EPRI has reported that adding FGD wastewater to surface impoundments used to treat ash transport water can reduce the settling efficiency in the impoundments due to gypsum particle dissolution, thus increasing the effluent TSS concentrations. Discharging wastewater containing elevated levels of TSS would likely result in also discharging other pollutants (*e.g.*, metals) in higher concentrations.[67] EPRI has also reported that FGD wastewater includes high loadings of volatile metals, which can increase the solubility of metals in surface impoundments, thereby leading to increased levels of dissolved metals and higher concentrations of metals in discharges from surface impoundments [EPRI, 2006].

Surface impoundments are also subject to seasonal turnover, which adversely affects their efficacy. During the summer, some surface impoundments become thermally stratified. When this occurs, the top layer of the impoundment is warmer and contains higher levels of dissolved oxygen, whereas the bottom layer of the impoundment is colder and can have significantly lower levels of oxygen and may develop anoxic conditions.[68] Typically, during fall, as the air temperature decreases, the upper layer of the impoundment becomes cooler and denser, thereby sinking and causing the entire volume of the impoundment to circulate. Solids that have collected at the bottom of the impoundment may become resuspended due to such mixing, increasing the concentrations of pollutants discharged during the turnover period. Seasonal turnover effects largely depend upon the size and configuration of the surface impoundment. Smaller, and especially shallow, surface impoundments likely do not experience turnover because they do not have physical characteristics that promote thermal stratification. However, some surface impoundments are large (*e.g.*, greater than 300 acres) and deep (*e.g.*, greater than 10 meters deep) and likely experience some degree of turnover.

Chemical precipitation and biological treatment are more effective than surface impoundments at removing both soluble and particulate forms of metals, as well as other pollutants such as nitrogen compounds and TDS. Because many of the pollutants of concern in FGD wastewater are present in dissolved form and would not be removed by surface impoundments, and because of the relatively large mass loadings of these pollutants (*e.g.*, selenium, dissolved mercury) discharged in the FGD wastestream, EPA decided not to finalize BAT effluent limitations for FGD wastewater based on surface impoundments.

EPA also rejected identifying chemical precipitation, alone, (Option A) as BAT 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. These pollutants of concern are discharged by steam electric power plants throughout the nation, causing adverse human health impacts and some of the most egregious environmental impacts (see the *Environmental Assessment for the Final Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*). In light of this, and the fact that economically achievable technologies are available to reduce these pollutants of concern, EPA determined that, by itself, chemical precipitation would not result in reasonable further progress toward the national goal of eliminating the discharge of all pollutants (see CWA section

[67] Although TSS is a conventional pollutant, whenever EPA would be regulating TSS in this final rule, it would be regulating it as an indicator pollutant for the particulate form of toxic metals.

[68] The anoxic, or low oxygen, conditions that are created at the bottom of surface impoundments do not achieve the same type of pollutant removals as a designed anoxic/anaerobic biological treatment system.

301(b)(2)(A)), and rejected that technology basis as BAT in favor of chemical precipitation followed by anaerobic/anoxic biological treatment.

EPA also decided not to establish, for all steam electric power plants, BAT limitations for FGD wastewater based on treatment using an evaporation system. In particular, this technology basis would employ a falling-film evaporator (also known as a brine concentrator) to produce a concentrated wastewater stream (brine) and a distillate stream.[69] While evaporation systems are effective at removing boron and pollutants that contribute to high concentrations of TDS, EPA decided it would not be appropriate to identify evaporation as the basis for BAT limitations for FGD wastewater at all steam electric power plants because of the high cost of possible regulatory requirements based on evaporation for discharges of FGD wastewater at existing facilities. The annual cost to the industry of limitations based on evaporation would be more than 2 and ½ times the cost to industry estimated for the final rule (after tax) (approximately $570 million more expensive than the final rule, on an annual basis, after tax). Given the high costs associated with the technology, and the fact that the steam electric industry is facing costs associated with several other rules in addition to this rule, EPA decided not to establish BAT limitations for FGD wastewater based on evaporation for all steam electric power plants. Nevertheless, the final rule does establish a voluntary incentives program under which steam electric power plants can choose to be subject to more stringent BAT limitations for FGD wastewater based on evaporation. See Section 8.3.13 for more discussion of the voluntary incentives program.

Although EPA has decided not to finalize BAT requirements based on evaporation for treating FGD wastewater at all steam electric power plants in the ELG, evaporation technology is potentially available and may be appropriate to achieve water quality-based effluent limitations, depending on site-specific conditions. For example, evaporation may be appropriate for those steam electric power plants that discharge upstream of drinking water treatment plants and whose discharge of bromide negatively impacts treatment of source waters at these treatment plants.

Finally, EPA decided not to establish a requirement that would direct permitting authorities to establish limitations for FGD wastewater using site-specific Best Professional Judgment (BPJ). Public commenters representing industry, state, and environmental group interests urged EPA not to establish any requirement that would leave BAT effluent limitations for FGD wastewater to be determined on a BPJ basis. Sections 301 and 304 of the CWA require EPA to develop nationally applicable ELGs based on the BAT, taking certain factors into account. EPA decided that it would not be appropriate to leave FGD wastewater requirements in the final rule to be determined on a BPJ basis because there are sufficient data to set uniform, nationally applicable limitations on FGD wastewater at plants across the nation. Given this, BPJ permitting of FGD wastewater would place an unnecessary burden on permitting authorities, including state and local agencies, to conduct a complex technical analysis that they may not have the resources or expertise to complete. BPJ permitting of FGD wastewater would also unnecessarily burden the regulated industry because of associated delays and uncertainty with respect to permits.

[69] This evaporation step would have been preceded by a chemical precipitation step using hydroxide precipitation, sulfide precipitation, and iron co-precipitation, as well as a softening step.

8.3.2 Fly Ash Transport Water

This rule identifies dry handling as the BAT technology basis for control of pollutants in fly ash transport water. Specifically, the technology basis for BAT is a dry vacuum system that employs a mechanical exhauster to pneumatically convey the fly ash (via a change in air pressure) from hoppers directly to a silo. Dry handling is clearly available to control the pollutants present in fly ash transport water. Today, the vast majority of steam electric power plants use dry handling techniques to manage fly ash, and by doing so avoid generating fly ash transport water. Based on data collected in the Steam Electric Survey, EPA estimates that approximately 80 percent of coal- and petroleum coke-fired generating units handle all fly ash with dry technologies. Another 13 percent of coal- and petroleum coke-fired generating units have both wet and dry fly ash handling systems (typically, the wet system is a legacy system that the plant has not decommissioned after retrofitting with a dry system). Only 7 percent of coal- and petroleum coke-fired generating units exclusively use a wet fly ash handling system and some of these plants manage the ash handling process so that they do not discharge fly ash transport water. As a result, EPA estimated that only 16 coal-fired steam electric power plants would incur costs to comply with a zero discharge BAT limitation for pollutants in fly ash transport water. See Section 7 for more information on the population of plants discharging fly ash transport water.

All new generating units built since the ELGs were last revised in 1982 have been subject to a zero discharge standard for pollutants in fly ash transport water. In nearly all cases, plants have installed dry fly ash handling technologies to comply with the standard. In addition, many owners and operators with generating units that are not subject to the previously established zero discharge NSPS for fly ash transport water have chosen to retrofit their units with dry fly ash handling technology to meet operational needs or for economic reasons. The trend in the industry is, moreover, toward the conversion and use of dry fly ash handling systems (see Section 4.5). Based on data collected in the Steam Electric Survey, EPA estimates that approximately 80 percent of coal- and petroleum coke-fired generating units operate dry fly ash handling systems (see Section 4.3.1). Since the survey, companies have continued to upgrade, or announce plans to upgrade, their ash handling systems at generating units (see Section 4.5).

EPA considered establishing BAT limitations for fly ash transport water based on chemical precipitation. Upon reviewing the discharge flow rates for fly ash transport water, however, EPA determined that the costs associated with chemical precipitation treatment were higher than the cost of the dry handling technology and chemical precipitation is less effective at removing pollutants. For these reasons, EPA did not select chemical precipitation as BAT for control of fly ash transport water [ERG, 2015d].

Dry ash handling does not adversely affect plant operation or reliability and it promotes the beneficial reuse of coal combustion residuals (CCRs). In addition, converting to dry fly ash handling eliminates the need to treat fly ash transport water in a surface impoundment, and it reduces the amount of wastes entering surface impoundments and the risk and severity of structural failures and spills.

EPA decided not to finalize a BAT limitation on fly ash transport water equal to the previously promulgated BPT limit on TSS, based on the technology of surface impoundments.

EPA concluded that it would not be appropriate to establish new BAT requirements equal to previously established BPT requirements for fly ash transport water because surface impoundments are not designed for or effective at removing dissolved metals and nutrients, which are pollutants of concern in fly ash transport water. Furthermore, they can be susceptible to seasonal turnover that degrades pollutant removal efficacy (see discussion in Section 8.3.1). Surface impoundments, therefore, would not result in reasonable further progress toward the national goal of eliminating the discharge of all pollutants.

8.3.3 Bottom Ash Transport Water

This rule identifies dry handling or closed-loop systems as the BAT technology basis for control of pollutants in bottom ash transport water.[70] More specifically, the first technology basis for BAT is a system in which bottom ash is collected in a water quench bath and a drag chain conveyor (mechanical drag system) then pulls the bottom ash out of the water bath on an incline to dewater the bottom ash. The second technology basis for BAT is a system in which the bottom ash is transported using the same processes as a wet-sluicing system, but instead of going to an impoundment, the bottom ash is sluiced to a remote mechanical drag system. Once there, a drag chain conveyor pulls the bottom ash out of the water on an incline to dewater the bottom ash, and the transport (sluice) water is then recycled back to the bottom ash collection system.

These technologies for control of bottom ash transport water are demonstrably available. Based on data collected in the Steam Electric Survey, approximately 20 percent of coal-fired and petroleum coke-fired steam electric power plants handle bottom ash using technologies that do not generate any bottom ash transport water and more than 80 percent of coal-fired generating units built in the last 20 years have installed dry bottom ash handling systems. In addition, 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 (dry handling or closed-loop wet ash handling) or planning to do so in the near future.

EPA considered establishing BAT limitations for bottom ash transport water based on chemical precipitation. Upon reviewing the discharge flow rates for bottom ash transport water, however, EPA determined that the costs associated with chemical precipitation treatment were comparable to the cost of control using dry handling/closed-loop systems and chemical precipitation is less effective at removing pollutants. For these reasons, EPA did not select chemical precipitation as BAT for control of bottom ash transport water [ERG, 2015d].

Dry bottom ash handling does not adversely affect plant operations or reliability and shifting to dry bottom ash systems offers certain benefits. As is the case for dry fly ash systems, shifting to dry bottom ash handling eliminates the need to send bottom ash transport water to a surface impoundment and it reduces the amount of waste entering surface impoundments and the risk and severity of structural failures and spills. Furthermore, one way companies can choose to comply with the final rule's requirement is to install a completely dry bottom ash system, which increases the energy efficiency of the boiler, thus reducing the amount of coal burned and associated emissions of carbon dioxide (CO_2) and other pollutants per MW of electricity

[70] EPA identified two technologies, a mechanical drag system or a remote mechanical drag system, as the BAT technology basis for bottom ash transport water because of potential space constraints at some plants' boilers.

generation [CBPG, 2013]. On an annual basis, EPA calculated significant fuel savings and reduced air emissions from such systems, the value of which EPA estimates to be $41 million to $117 million per year [Abt, 2015].[71]

EPA did not identify surface impoundments as BAT for bottom ash transport water because surface impoundments are not designed for or effective at removing dissolved metals and nutrients, which are pollutants of concern in bottom ash transport water. They are also susceptible to seasonal turnover that degrades pollutant removal efficacy (see discussion in Section 8.3.1). Moreover, in the steam electric power generating industry, bottom ash transport water is one of the three largest sources of discharges of pollutants of concern, and these discharges occur at many steam electric power plants across the nation. Thus, limitations based on surface impoundments would not result in reasonable further progress toward the national goal of eliminating the discharge of all pollutants (CWA section 301(b)(2)(A)).

Moreover, because the estimated overall cost of the ELG has decreased since proposal (see Section 9), EPA also decided that establishing different bottom ash transport water limitations for generating units of and below a certain size (other than 50 MW, as described in Section 8.3.12), as in Option C, was not warranted. At proposal and for the final rule, EPA considered an option that would have established differentiated bottom ash transport water requirements for units below 400 MW (Option C). Some public commenters stated that EPA's record does not support differentiated requirements for bottom ash transport water. They stated that BAT should be established at a level at which the costs are affordable to the industry as a whole, and that the cost to a unit in terms of dollars per amount of energy produced (in MW) is not a relevant factor. They cited EPA's record, which demonstrates that units of all sizes have installed dry handling and closed-loop systems, as well as EPA's economic achievability analysis, which does not show that units of 400 MW or less are especially likely to shut down if faced with a zero discharge requirement. Other commenters supported EPA's consideration of the relative magnitude of costs per amount of energy produced for units below or equal to 400 MW, as compared to larger units, as well as differentiated bottom ash transport water requirements for these units.

EPA reviewed its record and re-evaluated whether it would be appropriate to establish differentiated requirements for discharges of bottom ash transport water from existing sources based on unit size, in light of comments and the key changes since proposal. Annualized cost per amount of energy produced increases along a smooth curve moving from the very largest units to the smallest units [ERG, 2015f]. That, however, is expected due to economies of scale. Thus, there is no clear breaking point at which to establish a size threshold for purposes of differentiated requirements for bottom ash transport water.[72] Furthermore, EPA collected information in the industry survey that found that units of all sizes, including those less than 400 MW, have installed dry handling and closed-loop systems. And, as further described below, EPA projects a net retirement of only 843 MW under the final rule. This suggests that, as a group,

[71] Neither these savings nor the fuel and emissions reductions have been incorporated into EPA's analyses for this final rule.

[72] At the same time, costs per amount of energy produced do begin to increase very dramatically as one moves from units above 50 MW to units that are equal to 50 MW and smaller, and thus for reasons discussed in Section 8.3.12, the final rule establishes different requirements for units of 50 MW or less for several wastestreams, including bottom ash transport water.

units of 400 MW or less do not face particularly unique hardships under the final rule with respect to the industry as a whole. For these reasons, the final rule does not establish differentiated bottom ash transport water requirements for units equal to or below 400 MW (or for units equal to or below any other size threshold, other than 50 MW).

8.3.4 FGMC Wastewater

This rule identifies dry handling as the BAT technology basis for the control of pollutants in FGMC wastewater. More specifically, the technology basis for BAT is a dry vacuum system that employs a mechanical exhauster to convey the FGMC waste (via a change in air pressure) from hoppers directly to a silo. Dry handling of FGMC wastes is available and well-demonstrated in the industry; indeed, nearly all plants with FGMC systems use dry handling systems. Plants using sorbent injection systems (*e.g.*, activated carbon injection) to reduce mercury emissions from the flue gas typically handle the spent sorbent in the same manner as their fly ash (see Section 7). As of 2009, 92 percent of the industry generating FGMC waste uses dry handling to manage it. Only a few plants use wet systems to transport the spent sorbent to disposal in surface impoundments. Based on the Steam Electric Survey, the plants using wet handling systems operate them as closed-loop systems and do not discharge FGMC wastewater, or they already have a dry handling system that is capable of achieving zero discharge. Under the zero discharge limitation, these plants could choose to continue to operate their wet systems as closed-loop systems, or they could convert to dry handling technologies by managing the fly ash and spent sorbent together in a retrofitted dry system (rather than an impoundment) or by installing dedicated dry handling equipment for the FGMC waste similar to the equipment used for fly ash.

EPA is also aware of some plants that add oxidizing agents to the coal prior to burning it in the boiler. This chemical addition oxidizes the mercury present in the flue gas, which allows the plant to remove mercury more readily from the flue gas in the wet FGD system. EPA did not evaluate separate treatment technologies for using oxidizing agents to control flue gas mercury emissions because using oxidizing agents does not generate a separate FGMC wastestream.

EPA decided that it would not be appropriate to set BAT limitations for FGMC wastewater based on surface impoundments. While impoundments can effectively remove some particulate forms of metals and other pollutants, they are not designed for or effective at removing other pollutants of concern, such as dissolved metals and nutrients. They are also susceptible to seasonal turnover that degrades pollutant removal efficacy (see discussion in Section 8.3.1). Thus, they would not result in reasonable further progress toward the national goal of eliminating discharges of all pollutants (see CWA sections 101(a) and 301(b)(2)(A)).

8.3.5 Gasification Wastewater

This rule identifies evaporation as the BAT technology basis for the control of pollutants in gasification wastewater. More specifically, the technology basis for BAT is an evaporation system using a falling-film evaporator (or brine concentrator) to produce a concentrated wastewater stream (brine) and a reusable distillate stream. Evaporation, described in Section 7, is available and well-demonstrated in the industry for treatment of gasification wastewater. All three integrated gasification combined cycle (IGCC) plants now operating in the United States (the only existing sources of gasification wastewater) use evaporation technology to treat their gasification wastewater.

EPA did not identify surface impoundments as BAT for gasification wastewater because surface impoundments are not effective at removing the pollutants of concern present in gasification wastewater. They are also susceptible to seasonal turnover that degrades pollutant removal efficacy (see discussion in Section 8.3.1). In addition, one existing IGCC plant previously used a surface impoundment to treat its gasification wastewater, and the impoundment effluent repeatedly exceeded its National Pollutant Discharge Elimination System (NPDES) permit effluent limitations necessary to meet applicable water quality standards. Because of the demonstrated inability of surface impoundments to remove the pollutants of concern, particularly dissolved solids, and given that current industry practice is treatment of gasification wastewater using evaporation, EPA concluded that surface impoundments do not represent BAT for gasification wastewater.

EPA also considered including cyanide treatment as part of the technology basis for BAT (as well as NSPS, PSES, and PSNS) for gasification wastewater. EPA is aware that the Edwardsport IGCC plant, which began commercial operation in June 2013, includes cyanide destruction as one step in the treatment process for gasification wastewater. EPA, however, does not currently have sufficient data with which to calculate possible effluent limitations for cyanide. Thus EPA decided not to establish cyanide limitations or standards for gasification wastewater in this rule. This decision does not preclude permitting authorities from setting more stringent effluent limitations where necessary to meet water quality standards. In those cases, plants may elect to install additional treatment, like cyanide destruction, to meet water quality-based effluent limitations (WQBELs).

8.3.6 Combustion Residual Leachate

EPA received public comments expressing concern that the proposed definition of combustion residual leachate would apply to contaminated stormwater. Although this was not the Agency's intention, for the final rule, EPA revised the definition to make it clear that contaminated stormwater does not fall within the final definition of combustion residual leachate. This rule identifies surface impoundments as the BAT technology basis for control of pollutants in combustion residual leachate. Based on surface impoundments, which rely on gravity to remove particulates, this rule establishes a BAT limitation on TSS in combustion residual leachate equal to the previously promulgated BPT limitation on TSS in low volume waste sources. Few steam electric power plants currently employ technologies other than surface impoundments for treatment of combustion residual leachate. Throughout the development of this rule, EPA considered whether technologies in place for treatment of other wastestreams at steam electric power plants and wastestreams generated by other industries, including chemical precipitation, could be used for combustion residual leachate. At proposal, noting the small amount of pollutants in combustion residual leachate relative to other significant wastestreams at steam electric power plants, and that this was an area ripe for innovation, EPA requested additional information related to cost, pollutant reduction, and effectiveness of chemical precipitation and alternative approaches to treat combustion residual leachate. Commenters did not provide information that EPA could use to establish BAT limitations. Thus, EPA decided not to finalize BAT limitations for combustion residual leachate based on chemical precipitation

(Option E). The record demonstrates that the amount of pollutants collectively discharged in combustion residual leachate by steam electric power plants is a very small portion of the pollutants discharged collectively by all steam electric power plants (approximately 3 percent of baseline loadings, on a toxic-weighted basis). Given this, and the fact that this rule regulates the wastestreams representing the three largest sources of pollutants from steam electric power plants (including by setting a zero discharge standard for two out of the three wastestreams), EPA decided that this rule already represents reasonable further progress toward the CWA's goals. The final rule, therefore, establishes BAT limitations for combustion residual leachate equal to the BPT limitation on TSS for low volume waste sources.

8.3.7 Timing

As part of its consideration of the technological availability and economic achievability of the BAT limitations in the rule, EPA considered the magnitude and complexity of process changes and new equipment installations that would be required at facilities to meet the rule's requirements. As described in greater detail in Section 14, where BAT limitations in the ELG are more stringent than previously established BPT limitations, those limitations do not apply until a date determined by the permitting authority that is as soon as possible beginning November 1, 2018 (approximately three years following promulgation of the ELG), but that is also no later than December 31, 2023 (approximately eight years following promulgation).

Consistent with the proposed rule and supported by many commenters, EPA takes this approach in the ELG to provide the time that many plants need to raise capital, plan and design systems, procure equipment, and construct and then test systems. It also allows for consideration of plant changes being made in response to other Agency rules affecting the steam electric industry. Moreover, it enables facilities to take advantage of planned shutdown or maintenance periods to install new pollution control technologies.[73] EPA's decision is also designed to allow, more broadly, for the coordination of generating unit outages in order to maintain grid reliability and prevent any potential impacts on electricity availability, something that public commenters urged EPA to consider.

In addition, as requested by industry and states, the final rule and preamble clarify how the "as soon as possible date" is determined and implemented for steam electric power plants. The final rule specifies the factors that the permitting authority must consider in determining the "as soon as possible" date, and provides guidance on implementation with respect to timing in Section 14. In addition, the rule includes a "no later than" date of December 31, 2023, for implementation because, as public commenters pointed out, without such a date, implementation could be substantially delayed, and a firm "no later than" date creates a more level playing field across the industry. EPA's economic analysis assumes prompt renewal of permits and, thus, that the requirements of the rule will be fully implemented by 2023. While some commenters requested that EPA give permitting authorities the ability to extend the implementation period beyond December 31, 2023, in light of public comments received on the proposal, and the fact that plants can reasonably be expected to meet the new ELGs by December 31, 2023, this

[73] EPA's record demonstrates that plants typically have one or two planned shut-downs annually and that the length of these shutdowns is more than adequate to complete installation of relevant treatment and control technologies.

timeframe is appropriate given the CWA's pollutant discharge elimination goals (see CWA section 101(a)).

8.3.8 Legacy Wastewater

For purposes of the BAT limitations in this rule, EPA uses the term "legacy wastewater" to refer to FGD wastewater, fly ash transport water, bottom ash transport water, FGMC wastewater, or gasification wastewater generated prior to the date determined by the permitting authority that is as soon as possible beginning November 1, 2018, but no later than December 31, 2023 (see Section 8.3.7). Under this rule, legacy wastewater must comply with specific BAT limitations, which EPA is setting equal to the previously promulgated BPT limitations on TSS in the discharge of fly ash transport water, bottom ash transport water, and low volume waste sources.

EPA did not establish zero discharge BAT limitations for legacy wastewater because technologies that can achieve zero discharge (such as the ones on which the final BAT requirements discussed in Sections 8.3.2 through 8.3.4 are based) are not shown to be available for legacy wastewater. Legacy wastewater already exists in wet form, and thus dry handling could not be used eliminate its discharge. Furthermore, EPA lacks data to show that legacy wastewater could be reliably incorporated into a closed-loop process that eliminates discharges, given the variation in operating practices among surface impoundments containing legacy wastewater.

EPA also decided not to establish BAT limitations for legacy wastewater based on a technology other than surface impoundments (chemical precipitation, chemical precipitation plus biological treatment, evaporation) because it does not have the data to do so. Data are not available because of the way that legacy wastewater is currently handled at plants.

The vast majority of plants combine some of their legacy wastewater with each other and with other wastestreams, including cooling water, coal pile runoff, metal cleaning wastes, and low volume waste sources in surface impoundments. [74] Once combined in surface impoundments, the legacy wastewater no longer has the same characteristics that it did when it was first generated. For example, the addition of cooling water can dilute legacy wastewater to a point where the pollutants are no longer present at treatable levels. Additionally, some wastestreams have significant variations in flow, such as metal cleaning wastes, which are generally infrequently generated, or coal pile runoff, which is generated during precipitation events. Because surface impoundments are typically open, with no cover, they also receive direct precipitation. As a result of all of this, the characteristics of legacy wastewater contained in surface impoundments (flow rate and pollutant concentrations) vary at both any given plant, as well as across plants nationwide. Furthermore, EPA generally would like to have enough performance data at a well-designed, well-operated plant or plants to derive limitations and standards using its well-established and judicially upheld statistical methodology. In this case,

[74] For example, there are 65 plants for which EPA estimated FGD wastewater compliance costs and that use an impoundment as part of their treatment system. For 54 of the 65 plants (83 percent), the FGD wastewater is commingled with, at least, fly and/or bottom ash transport water, and for another eight of the 65 plants (12 percent), the FGD wastewater is commingled with non-ash wastewater, such as cooling tower blowdown or low volume waste sources [ERG, 2015g].

except in limited circumstances, plants do not treat the legacy wastewater that they send to an impoundment using anything beyond the surface impoundment itself.[75] Thus, the final rule establishes BAT limitations for legacy wastewater equal to the previously promulgated BPT limitations on TSS in discharges of fly ash transport water, bottom ash transport water, and low volume waste sources.

Finally, while there are a few plants that discharge from an impoundment containing only legacy FGD wastewater, [76] EPA rejected establishing requirements for such legacy FGD wastewater based on a technology other than surface impoundments. EPA determined that, while it could be possible for plants to treat the legacy FGD wastewater with the same technology used to treat FGD wastewater subject to the BAT limitations described in Section 8.3.1 (because their characteristics could be similar), establishing requirements based on any technology more advanced than surface impoundments for these legacy "FGD-only" wastewater impoundments could encourage plants to alter their operations prior to the date that the final limitations apply in order to avoid the new requirements. Likely, a plant would begin commingling other process wastewater with their legacy FGD wastewater in the impoundment so that any legacy "FGD-only" wastewater requirements would no longer apply. Alternatively, plants might choose to pump the legacy FGD wastewater out of the impoundment on an accelerated schedule and prior to the date that the final limitations apply. In this case, the more rapid discharge of the wastewater could result in temporary increases in environmental impacts (*e.g.*, exceedances of water quality criteria for acute impacts to aquatic life). EPA wanted to avoid creating such a perverse incentive in this rule, and it therefore decided to establish BAT limitations for discharges of legacy FGD wastewater based on the previously promulgated BPT limitations on TSS for low volume waste sources. Finally, EPA notes that, as a result of the zero discharge requirements for discharges of all pollutants in three wastestreams (fly ash transport water, bottom ash transport water, and flue gas mercury control wastewater, this rule provides strong incentives for steam electric power plants to greatly reduce, if not completely eliminate, the disposal and treatment of their major sources of ash-containing wastewater in surface impoundments. As a result, EPA anticipates that overall volumes of legacy wastewater will continue to decrease dramatically over time, as this rule becomes fully implemented.

8.3.9 Economic Achievability

EPA's analysis for the final BAT limitations demonstrates that they are economically achievable for the steam electric industry as a whole, as required by CWA section 301(b)(2)(A). EPA performed cost and economic impact assessments on existing plants using the Integrated

[75] For example, no plant uses chemical precipitation, biological treatment, or evaporation to treat its legacy fly ash transport water or legacy bottom ash transport water contained in an impoundment, including any impoundment that may contain only legacy fly ash transport water or only legacy bottom ash transport water. Thus, no steam electric industry data exist to establish BAT limitations for possible "fly ash-only" impoundments or "bottom ash-only" impoundments based on these technologies.

[76] EPA determined that there are three plants that are estimated to incur FGD wastewater compliance costs and that use an impoundment as part of the treatment system, but where the FGD wastewater is not commingled with other process wastewaters in the impoundment. There are no plants that discharge from an impoundment containing only gasification wastewater.

Planning Model (IPM)[77] using a baseline that reflects impacts from other relevant environmental regulations (see the *Regulatory Impact Analysis for Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*). For the ELG, the model showed very small effects on the electricity market, on both a national and regional sub-market basis. Based on the results of these analyses, EPA estimated that the requirements associated with the ELG would result in a net reduction of 843 MW in steam electric generating capacity as of the model year 2030, reflecting full compliance by all plants. This capacity reduction corresponds to a net effect of two unit closures or, when aggregating to the level of steam electric generating plants, and net plant closure.[78] These results support EPA's conclusion that the ELG is economically achievable.

8.3.10 Non-Water Quality Environmental Impacts, Including Energy Requirements[79]

The final BAT effluent limitations have acceptable non-water quality environmental impacts, including energy requirements (see Section 12 for more detail EPA's analysis of these impacts). EPA estimates that by the year 2023, under the final rule and reflecting full compliance, energy consumption increases by less than 0.01 percent of the total electricity generated by power plants. EPA also estimates that the amount of fuel consumed by increased operation of motor vehicles (*e.g.*, for transporting fly ash) increases by approximately 0.002 percent of total fuel consumption by all motor vehicles.

As discussed in Section 12, EPA also evaluated the effect of the BAT effluent limitations on air emissions generated by all electric power plants (NO_X, sulfur oxides (SO_X), and CO_2), solid waste generation, and water usage. Under the final rule, NO_X emissions are projected to decrease by 1.16 percent, SO_X emissions are projected to increase by 0.04 percent, and CO_2 emissions are projected to decrease by 0.106 percent due to changes in the mix of electricity generation (e.g., less electricity from coal-fired steam electric generating units and more electricity from natural gas-fired steam electric generating units). Moreover, solid waste generation is projected to increase by less than 0.001 percent of total solid waste generated by all electric power plants. Finally, EPA estimates that the final rule has a positive impact on water use, with steam electric power plants reducing the amount of water they withdraw by 57 billion gallons per year (155 million gallons per day).

[77] IPM is a comprehensive electricity market optimization model that can evaluate such impacts within the context of regional and national electricity markets.

[78] Given the design of IPM, unit-level and thereby plant-level projections are presented as an indicator of overall regulatory impact rather than a precise prediction of future unit–level or plant-specific compliance actions.

[79] As described in Section 8.3.13, this rule includes a voluntary incentives program that provides the certainty of more time for plants to implement new BAT requirements, if they adopt additional process changes and controls that achieve limitations on mercury, arsenic, selenium, and TDS in FGD wastewater, based on evaporation technology. The information presented in this section assumes plants will choose to comply with BAT limitations for FGD wastewater based on chemical precipitation and biological treatment. EPA does not know how many plants will opt into the voluntary incentives program. Therefore, EPA also calculated non-water quality environmental impacts assuming all plants will elect to comply with the voluntary incentives program and similarly found these impacts to be acceptable [ERG, 2015h].

8.3.11 Impacts on Residential Electricity Prices and Low-Income and Minority Populations

EPA examined the effects of the ELG on consumers as an additional factor that might be appropriate when considering what level of control represents BAT. If all compliance costs were passed on to residential consumers of electricity, instead of being borne by the operators and owners of power plants (a very conservative assumption), the average monthly increase in electricity bill for a typical household would be no more than $0.12 under the final rule.

EPA also considered the effect of the rule on minority and low-income populations. As explained in Section XVII.J of the preamble, using demographic data regarding who resides closest to steam electric power plant discharges and who consumes the most fish from waters receiving power plant discharges, EPA concluded that low-income and minority populations benefit to an even greater degree than the general population from the reductions in discharges associated with the final rule.

8.3.12 Existing Oil-Fired Generating Units and Small Generating Units

EPA considered whether subcategorization of the ELGs was warranted based on the factors specified in CWA section 304(b)(2)(B) and other factors identified in public comments. Ultimately, EPA concluded it would be appropriate to set different limitations for existing small generating units (units with a nameplate capacity of 50 MW or less) and existing oil-fired generating units. No other, different requirements were warranted for this ELG under the factors considered (see Section 5 for more detail).

Oil-fired Generating Units. For oil-fired generating units, the final rule establishes BAT limitations for FGD wastewater, fly ash transport water, bottom ash transport water, FGMC wastewater, and gasification wastewater equal to previously established BPT limitations on TSS in fly ash transport water, bottom ash transport water, and low volume waste sources. As defined in the rule, oil-fired generating units refer to those that use oil as either the primary or secondary fuel and do not burn coal or petroleum coke. Units that use only oil during startup or for flame stabilization are not considered oil-fired generating units. EPA decided to finalize these limitations for oil-fired generating units because EPA's record demonstrates that, in comparison to coal- and petroleum coke-fired generating units, oil-fired generating 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.

The amount of ash generated by oil-fired generating units is a small fraction of the amount produced by coal-fired units. Coal-fired units generate hundreds to thousands of tons of ash each day, with some plants generating more than 2,000 tons per day. In contrast, oil-fired units generate less than ten tons of ash per day. This disparity is also apparent when comparing the ash tonnage to the amount of power generated, with coal-fired generating units producing nearly 1,800 times more ash than oil-fired generating units (0.6 tons per MW-hour on average for coal units; 0.000319 tons per MW-hour on average for oil units). The amount of pollutants discharged to surface waters is roughly correlated to the amount of ash wastewater discharged; thus, oil-fired generating units discharge substantially fewer pollutants to surface waters than coal-fired units, even when generating the same amount of electricity. EPA estimates that the amount of pollutants discharged collectively by all oil-fired generating units is a very small portion of the pollutants discharged collectively by all steam electric power plants (less than one percent, on a toxic-weighted basis).

Oil-fired generating units are generally among the oldest steam electric generating units in the industry. Eighty-seven percent of the generating units are more than 25 years old and more than a quarter of the generating units began operation more than 50 years ago. Based on responses to the Steam Electric Survey, fewer than 20 oil-fired generating units discharged fly ash or bottom ash transport water in 2009. This is likely because only about 20 percent of oil-fired generating units operate as baseload units; the rest are either cycling/intermediate units (about 45 percent) or peaking units (about 35 percent). These units also have notably low capacity utilization. While about 30 percent of the baseload units report capacity utilization greater than 75 percent, almost half report a capacity utilization of less than 25 percent. Eighty percent of the cycling/intermediate units and all peaking units also report capacity utilization less than 25 percent. Thirty-five percent of oil-fired generating units operated for more than 6 months in 2009; nearly half of the units operated for less than 30 days.

While these older and generally intermittently operated oil-fired generating units are capable of installing and operating the treatment technologies that form the bases for this rule, and the costs would be affordable for most plants, EPA concludes that, due to the factors described here, companies may choose to shut down these oil-fired units instead of making new investments to comply with the ELG. If these units shut down, EPA is concerned about resulting reductions in the flexibility that grid operators have during peak demand due to less reserve generating capacity to draw upon. But, more importantly, maintaining a diverse fleet of generating units that includes a variety of fuel sources is vital to the nation's energy security. Because the supply/delivery network for oil is different from other fuel sources, maintaining the existence of oil-fired generating units helps ensure reliable electric power generation as commenters confirmed.

Based on responses to the Steam Electric Survey, EPA estimates that less than 20 oil-fired generating units discharged fly ash or bottom ash transport water in 2009. At the same time, EPA notes that many oil-fired generating units operate infrequently, which could contribute to the relatively low numbers of units discharging ash-related wastewater. Should more widespread operation of oil-fired generating units be required to meet demands of the electric grid, additional plants may find it necessary to discharge ash transport water.

EPA considered these potential impacts on electric grid reliability and the nation's energy security, under CWA section 304(b)(2)(B), in its decision to establish different BAT limitations for oil-fired generating units.

<u>Small Generating Units</u>. The final rule also establishes BAT limitations for FGD wastewater, fly ash transport water, bottom ash transport water, FGMC wastewater, and gasification water at small generating units equal to previously established BPT limitations on TSS for fly ash transport water, bottom ash transport water, and low volume waste sources. For purposes of this rule, small generating units refer to those units with a total nameplate generating capacity of 50 MW or less. EPA decided to establish these different BAT limitations for small

generating units because they are more likely to incur compliance costs that are significantly and disproportionately higher per amount of energy produced (dollars per MW) than those incurred by large generating units.

Some commenters stated that the cost to a unit in terms of dollars per MW is not relevant because BAT should be established at a level at which the costs are affordable to the industry as a whole. They noted that EPA's IPM analysis demonstrates that the most stringent proposed regulatory option is economically achievable for all units above 50 MW [ERG, 2015f]. Other commenters supported EPA's consideration of the relative magnitude of costs for smaller units compared to larger units, and some suggested EPA should increase the size threshold to 100 MW because those units also have disproportionate costs per amount of energy produced, and they collectively discharge a small fraction of the total pollutants discharged by all steam electric power plants.

EPA reviewed the record and re-evaluated the threshold for small units in light of comments and the key changes since proposal. EPA considered establishing no threshold, as well as several different size thresholds, for small units. The Agency looked closely at establishing a threshold at 50 MW or 100 MW. While the total amount of pollutants discharged by units at these thresholds is relatively small in comparison to those discharged by all steam electric power plants, the amount of pollutants discharged by units smaller than or equal to 100 MW is almost double the amount of pollutants discharged by units smaller than or equal to 50 MW [ERG, 2015f]. The record indicates that the cost per unit of energy produced increases as the size of the generating unit decreases, and while there is no clear "knee of the curve" at which to establish a size threshold, there is a difference between units at 50 MW and below compared to those above 50 MW. Figure 8-1, below, shows the annualized cost per amount of energy produced for existing units under Regulatory Option D. Figure 8-1 shows that the cost per amount of energy produced increases as the size of the generating unit decreases. Annualized cost per amount of energy produced increases gradually as one moves from the very largest units down to 100 MW, and then the cost per amount of energy produced begins to increase more rapidly as one moves from 100 MW down to 50 MW, until it increases very rapidly for units at 50MW and below. Additionally, Figure 8-1 shows that nearly all of the ratios of cost to amount of energy produced for units smaller than or equal to 50 MW are above those for the entire population of remaining units. The same cannot be said of the ratio for units smaller than or equal to 100 MW.

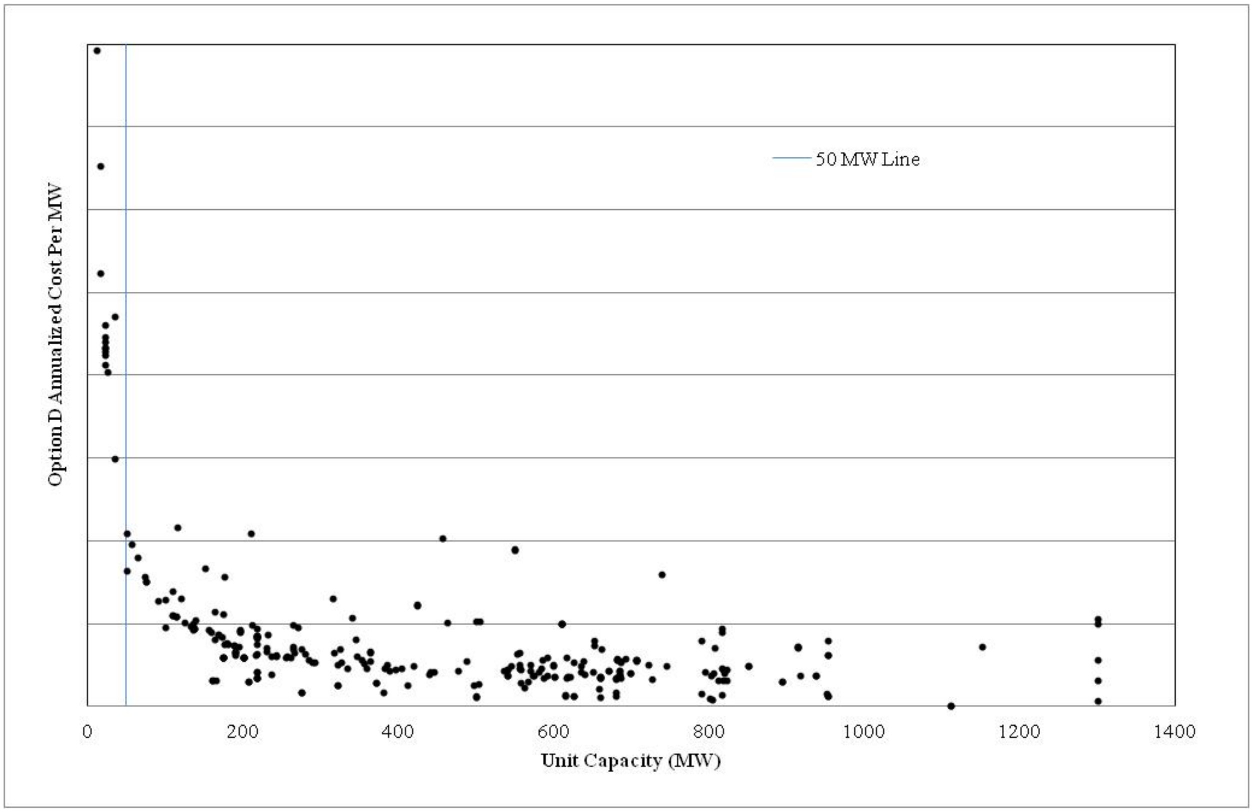

Figure 8-1. Regulatory Option D Annualized Cost Per MW Compared to Unit Capacity (MW)

In light of the fact that the costs per amount of energy produced are significantly and disproportionately higher for units smaller than or equal to 50 MW compared to larger units, and in light of the very small fraction of pollutants discharged by units smaller than or equal to 50MW, EPA ultimately decided to establish different requirements for units at this threshold. Keeping in mind the statutory directive to set effluent limitations that result in reasonable further progress toward the national goal of eliminating the discharge of all pollutants (CWA section 301(b)(2)(A)), EPA used its best judgment to balance the competing interests. EPA recognizes that any attempt to establish a size threshold for generating units will be imperfect due to individual differences across units and firms. EPA concludes, however, that a threshold of 50 MW or less reasonably and effectively targets those generating units that should receive different treatment based on the considerations described above, while advancing the CWA's goals. Furthermore, EPA's analysis demonstrates that the final rule, with a threshold established at 50 MW, is economically achievable.

8.3.13 Voluntary Incentives Program

As part of BAT for existing sources, the final rule establishes a voluntary incentives program that provides the certainty of more time (until December 31, 2023) for plants to implement the BAT requirements, if they adopt additional process changes and controls that achieve limitations on mercury, arsenic, selenium, and TDS in FGD wastewater, based on evaporation technology (see Section 8.3.1 for a more complete description of the evaporation technology basis). This optional program provides significant environmental protections beyond those achieved by the final BAT limitations for FGD wastewater based on chemical precipitation plus biological treatment because evaporation technology is capable of achieving significant removals of toxic metals, as well as TDS.[80] EPA's proposal included a voluntary incentives program that contained, as one element, incentives in the form of additional implementation time for plants that eliminate the discharge of all process wastewater (except cooling water). Public commenters urged EPA to consider establishing, instead, a program that provided incentives for plants that go further than the rule's requirements to reduce discharges from individual wastestreams. Because the final rule already contains zero discharge limitations for several key wastestreams, EPA decided that the voluntary incentives program should focus on FGD wastewater.

EPA concluded that additional pollutant reductions could be achieved under a voluntary incentives program because there are certain reasons a plant might opt to treat its FGD wastewater using evaporation rather than chemical precipitation plus biological treatment. One such reason is the possibility that a plant's NPDES permit may need more stringent limitations necessary to meet applicable water quality standards. For example, some power plant discharges containing TDS (including bromide) that occur upstream of drinking water treatment plants can negatively impact treatment of source waters at the drinking water treatment plants. A recent study identified four drinking water treatment plants that experienced increased levels of bromide in their source water, and corresponding increases in the formation of carcinogenic disinfection by-products (brominated DPBs) in the finished drinking water, after the installation of wet FGD scrubbers at upstream steam electric power plants [McTigue *et al.*, 2014].

Furthermore, based on trends in the industry and experience with this and other industries, EPA expects that, over time, the costs of evaporation (and other technologies that could achieve the limitations in the voluntary incentives program, including zero discharge practices) will decrease so as to make it an even more attractive option for plants. EPA understands that vendors are already working on changes to this technology to reduce the costs, reduce the amount of solids generated, and improve the solids handling. See Section 7.1.4.

The technology on which the BAT limitations in the voluntary incentives program are based, evaporation, is available to steam electric power plants. EPA identified three plants in the U.S. that have installed, and one plant that is in the process of installing, evaporation systems to treat their FGD wastewater. Four coal-fired power plants in Italy treat FGD wastewater using evaporation. See Section 7. Furthermore, the voluntary program is economically achievable because only those plants that opt to be subject to the BAT limitations based on evaporation, rather than the BAT limitations based on chemical precipitation plus biological treatment, must achieve them. Therefore, any plant that chooses to be subject to the more stringent limitations has determined for itself, in light of its own financial information and economic outlook, that such limitations are economically achievable. Finally, EPA analyzed the non-water quality environmental impacts and energy requirements associated with the voluntary incentives program, and it found them acceptable [ERG, 2015h].

[80] Properly operated evaporated systems are also capable of achieving the BAT limitations based on chemical precipitation plus biological treatment.

The development of this voluntary incentives program furthers the CWA's ultimate goal of eliminating the discharge of pollutants into the Nation's waters. See CWA section 101(a)(1) and section 301(b)(2)(A) (specifying that BAT will result in "reasonable further progress toward the national goal of eliminating the discharge of pollutants"). While the final rule's BAT limitations based on chemical precipitation plus biological treatment represent "reasonable further progress," the voluntary incentives program is designed to press further toward achieving the national goal of the Act, as wastewater that has been treated properly using evaporation has very low pollutant concentrations (also making it possible to reuse the wastewater and completely eliminate the discharge of any pollutants). In addition, CWA section 104(a)(1) gives the Administrator authority to establish national programs for the prevention, reduction, and elimination of pollution, and it provides that such programs shall promote the acceleration of research, experiments, and demonstrations relating to the prevention, reduction, and elimination of pollution. EPA anticipates that this voluntary incentives program will effectively accelerate the research into, and demonstration of controls and processes intended to prevent, reduce, and eliminate pollution because, under it, plants will opt to employ control and treatment strategies to significantly reduce discharges of pollutants found in FGD wastewater.

Steam electric power plants agreeing to meet BAT limitations for FGD wastewater based on evaporation must comply with those limitations on arsenic, mercury, selenium, and TDS in FGD wastewater.[81] For such plants, the BAT limitations based on evaporation apply as of December 31, 2023, to FGD wastewater generated on and after December 31, 2023. Plants opting to participate in the voluntary program can use the period in advance of this date to research, engineer, design, procure, construct, and optimize systems capable of meeting the limitations based on evaporation.

For purposes of the voluntary incentives program BAT limitations, legacy FGD wastewater is FGD wastewater generated prior to December 31, 2023. For such legacy FGD wastewater, the final rule establishes BAT limitations on TSS in discharges of FGD wastewater that are equal to BPT limitations for low volume waste sources.

EPA decided not to make the voluntary incentives program available to plants that send their FGD wastewater to POTWs. Under CWA section 307(b)(1), PSES must specify a time for compliance that does not exceed three years from the date of promulgation, and thus the additional time of up to 2023 cannot be given to indirect dischargers. Of course, nothing prohibits an indirect discharger from using any technology, including evaporation, to comply with the final PSES and PSNS.

EPA expects that any plant interested in the voluntary incentives program would indicate their intent to opt into the program prior to issuance of its next NPDES permit, following the effective date of this rule. A plant can indicate its intent to opt into the voluntary program on its permit application or through separate correspondence to the NPDES Director, as long as the signatory requirements of 40 CFR § 122.22 are met.

[81] For some plants, proper pretreatment such as softening or chemical precipitation is likely appropriate to ensure effective and efficient operation of evaporation systems.

8.4 BEST AVAILABLE DEMONSTRATED CONTROL TECHNOLOGY/NSPS

After considering all of the technologies described in Section 7, as well as public comments, and in light of the factors specified in section 306 of the CWA, EPA concluded that the technologies described in Option F represent the best available demonstrated control technology (BADCT) for steam electric power plants, and the final rule promulgates NSPS based on that option. Thus, the final NSPS establish:

- Standards on arsenic, mercury, selenium, and TDS in FGD wastewater, based on evaporation (same basis as for BAT limitations in the voluntary incentives program).
- A zero discharge standard on all pollutants in bottom ash transport water, based on dry handling or closed-loop systems (same bases as for BAT limitations).
- A zero discharge standard on all pollutants in FGMC wastewater, based on dry handling (same bases as for BAT limitations).
- Standards on mercury, arsenic, selenium, and TDS in gasification wastewater, based on evaporation technology (same bases as for BAT limitations).
- Standards on mercury and arsenic in discharges of combustion residual leachate, based on chemical precipitation (more specifically, the technology basis is a chemical precipitation system that employs hydroxide precipitation, sulfide precipitation, and iron coprecipitation to remove heavy metals).

The ELG also maintains the previously established zero discharge NSPS on discharges of fly ash transport water, based on dry handling.

The record indicates that the technologies that serve as the bases for NSPS in the ELG are well-demonstrated, based on the performance of plants using the technologies. For example:

- New steam electric power generating sources have been meeting the previously established zero discharge standard for fly ash transport water since 1982, predominantly by using dry handling technologies.
- Three plants in the U.S. and four plants in Italy use evaporation technology to treat their FGD wastewater, and another U.S. plant is in the process of installing such technology for that purpose.
- Of the approximately 50 coal-fired generating units built within the last 20 years, most (83 percent) manage their bottom ash without using water to transport the ash and, as a result, do not discharge bottom ash transport water.
- The technology identified as BAT for gasification wastewater represents current industry practice. Every IGCC power plant currently in operation uses evaporation to treat their gasification wastewater, even when the wastewater is not discharged and is instead reused at the plant.
- In the case of FGMC wastewater, every plant currently using post-combustion sorbent injection (*e.g.*, activated carbon injection) either handles the captured spent sorbent with a dry process or manages the FGMC wastewater so that it is not discharged to surface waters (or has the capability to do so).

- For combustion residual leachate, chemical precipitation is a well-demonstrated technology for removing metals and other pollutants from a variety of industrial wastewaters, including combustion residual leachate from landfills not located at power plants. Chemical precipitation is also well-demonstrated at steam electric power plants for treatment of FGD wastewater that contains the pollutants in combustion residual leachate.

The NSPS in the ELG also pose no barrier to entry. The cost to install technologies at new units is typically less than the cost to retrofit existing units. For example, the cost differential between Options B, C, and D for existing sources is mostly associated with retrofitting controls for bottom ash handling systems. For new sources, however, NSPS based on Option F do not present plants with the same choice of retrofit versus modification of existing processes because every new generating unit must install some type of bottom ash handling system as the unit is constructed. Establishing a zero discharge standard for pollutants in bottom ash transport water as part of NSPS means that new steam electric power plants will install a dry bottom ash handling system instead of a wet-sluicing system.

Moreover, EPA assessed the possible impacts of the final NSPS on new sources by comparing the incremental costs of the Option F technologies to the costs of hypothetical new generating units. EPA is not able to predict which plants might construct new units or the exact characteristics of such units. Instead, EPA calculated and analyzed compliance costs for a variety of plant and unit configurations. EPA developed NSPS compliance costs for new sources using a methodology similar to the one used to develop compliance costs for existing sources. EPA's estimates for compliance costs for new sources are based on the net difference in costs between wastewater treatment system technologies that would likely have been implemented at new sources under the previously established regulatory requirements, and those that would likely be implemented under the final rule. EPA estimated that the incremental compliance costs for a new generating unit (capital and O&M) represent approximately 3.3 percent of the annualized cost of building and operating a new 1,300 MW coal-fired plant, with capital costs representing 0.3 to 2.8 percent of the overnight construction costs, and annual O&M costs representing 0.3 to 3.9 percent of the fuel and other O&M cost of operating a new plant.

Finally, EPA analyzed the non-water quality environmental impacts associated with Option F for existing sources, and its analysis is relevant to the consideration of non-water quality environmental impacts associated with Option F for new sources. Since there is nothing inherently different between an existing and new source, EPA's analysis with respect to existing sources is instructive. Using this analysis, EPA determined that NSPS based on the Option F technologies have acceptable non-water quality environmental impacts and energy requirements [ERG, 2015h; ERG, 2015e].

In contrast to the BAT effluent limitations, EPA establishes the same NSPS for oil-fired generating units and small generating units as for all other new sources. A key factor that affects compliance costs for existing sources is the need to retrofit new pollution controls to replace existing pollution controls. New sources do not incur retrofit costs because the pollution controls (process operations or treatment technology) are installed at the time of construction. Thus, the costs for new sources are lower, even if the pollution controls are identical.

For each of the wastestreams except combustion residual leachate, EPA rejected establishing NSPS based on surface impoundments for the same reasons it rejected establishing BAT based on surface impoundments. For FGD wastewater, EPA also did not establish NSPS based on chemical precipitation for the same reasons it rejected establishing BAT based on that technology. In particular, these other technologies would not achieve as much pollutant reduction as the technology bases in Option F – which is technologically available and economically achievable with acceptable non-water quality environmental impacts and energy requirements – and thus do not represent best available demonstrated control technology.

EPA did not select surface impoundments as the basis for NSPS for combustion residual leachate because, unlike BAT, NSPS represent the "greatest degree of effluent reduction . . . achievable" (CWA section 306), and (besides "cost" and "any non-water quality environmental impact and energy requirements") EPA does not consider "other factors" in establishing NSPS. When used to treat combustion residual leachate, chemical precipitation can achieve substantial pollutant reductions as compared to surface impoundments. Thus, EPA has determined that NSPS for leachate based on chemical precipitation achieve the "greatest degree of effluent reduction" as that term is used in CWA section 306.

Similarly, EPA did not select chemical precipitation plus biological treatment as the basis for NSPS for FGD wastewater because, under CWA section 306, NSPS reflect "the greatest degree of effluent reduction . . . achievable." Evaporation systems are capable of achieving extremely low pollutant discharge levels, and in fact can be the basis for a plant completely eliminating all discharges associated with FGD wastewater. Moreover, unlike EPA's decision not to identify evaporation as the technology basis for FGD wastewater discharges from all existing sources due to the large associated cost, establishing NSPS for FGD wastewater based on evaporation does not add to the overall estimated cost of the rule because EPA does not predict any new coal-fired generating units will be installed in the foreseeable future. As explained above, however, in the event that a new unit is installed, EPA determined that the NSPS compliance costs would not present a barrier to entry.

8.5 PSES

The CWA requires EPA to promulgate pretreatment standards for pollutants that are not susceptible to treatment by POTWs or that would interfere with the operation of POTWs. Unlike direct dischargers whose wastewater will receive no further treatment once it leaves the plant, indirect dischargers send their wastewater to POTWs for further treatment. Therefore, in setting PSES, in addition to considering the factors assessed for BAT, EPA must also determine whether a pollutant "passes through" secondary treatment at a POTW.

Table 8-2 summarizes the results of EPA's pass-through analysis for the regulated pollutants (with numeric limitations) in each wastestream, as controlled by the relevant BAT and NSPS technology basis.[82] As explained in Section 11, EPA did not conduct its traditional pass-through analysis for wastestreams with zero discharge limitations or standards. Zero discharge

[82] The regulation of TSS in combustion residual leachate (based on surface impoundments) under the final BAT limitations is not represented here because TSS is a conventional pollutant that is effectively treated by POTWs (it does not pass through).

limitations and standards achieve 100 percent removal of pollutants; therefore, all pollutants in those wastestreams pass through the POTW. As shown in the table, all of the pollutants regulated under BAT/NSPS pass through secondary treatment by a POTW.

Table 8-2. Summary of Pass-Through Analysis

Technology Option	Pollutant	Pass Through? (Yes or No)
Chemical Precipitation for Combustion Residual Leachate (only for NSPS)	Arsenic	Yes
	Mercury	Yes
Chemical Precipitation Plus Biological Treatment for FGD wastewater	Arsenic	Yes
	Mercury	Yes
	Nitrate Nitrite as N	Yes
	Selenium	Yes
Evaporation for FGD Wastewater (only for NSPS)	Arsenic	Yes
	Mercury	Yes
	Selenium	Yes
	TDS	Yes
Evaporation for Gasification Wastewater	Arsenic	Yes
	Mercury	Yes
	Selenium	Yes
	TDS	Yes

After considering all of the relevant factors and technology options described in Section 7, as well as public comments, as is the case with BAT, EPA decided to establish PSES based on the technologies described in Option D. For PSES, the final rule establishes:

- Standards on arsenic, mercury, selenium, and nitrate-nitrite as N in FGD wastewater, based on chemical precipitation plus biological treatment.
- A zero discharge standard on all pollutants in fly ash transport water, based on dry handling.
- A zero discharge standard on all pollutants in bottom ash transport water, based on dry handling or closed-loop systems.
- A zero discharge standard on all pollutants in FGMC wastewater, based on dry handling.
- Standards on mercury, arsenic, selenium, and TDS in gasification wastewater, based on evaporation technology.[83]

[83] For small (50 MW or smaller) and oil-fired generating units, EPA is not finalizing PSES for fly ash transport water, bottom ash transport water, FGMC wastewater, and gasification wastewater.

All of the technology bases for the final PSES are the same as those described for the final BAT limitations. The final rule does not establish PSES for combustion residual leachate because TSS and the pollutants that it represents do not pass through POTWs.

EPA selected the Option D technologies as the basis for PSES for the same reasons that EPA selected the Option D technologies as the bases for BAT. EPA's analysis shows that, for both direct and indirect dischargers, the Option D technologies are available and economically achievable, and Option D has acceptable non-water quality environmental impacts, including energy requirements (see Section 12). EPA rejected other options for PSES for the same reasons that it rejected other options for BAT. Furthermore, for the same reasons that apply to EPA's final BAT limitations for oil-fired generating units and small generating units, and described in Section 8.3.12, EPA does not establish PSES that would apply to oil-fired generating units and small generating units (50 MW or smaller). [84] Finally, EPA determined that the final PSES prevent pass-through of pollutants from POTWs into receiving streams and also help control contamination of POTW sludge.

As with the final BAT limitations, in considering the availability and achievability of the final PSES, EPA concluded that existing indirect dischargers need some time to achieve the new standards, in part to avoid forced outages (see Section 8.3.7). However, in contrast to the BAT limitations (which apply on a date determined by the permitting authority that is as soon as possible beginning November 1, 2018, but no later than December 31, 2023), the new PSES apply as of November 1, 2018. Under CWA section 307(b)(1), pretreatment standards shall specify a time for compliance not to exceed 3 years from the date of promulgation, so EPA cannot establish a longer implementation period. Moreover, unlike requirements on direct discharges, requirements on indirect discharges are not implemented through an NPDES permit and thus are not subject to awaiting the next permit issuance before the limitations are specified clearly for the discharger. EPA has determined that all of the existing indirect dischargers can meet the standards by November 1, 2018, and because there are relatively few indirect dischargers (who would have approximately 3 years from the date of promulgation to achieve the standards), implementing the standards by that date would not lead to electricity availability concerns (see the RIA).

For purposes of the PSES in this rule, the term "legacy wastewater" refers to FGD wastewater, fly ash transport water, bottom ash transport water, FGMC wastewater, or gasification wastewater generated prior to November 1, 2018. For the same reasons that EPA decided to establish BAT limitations on TSS in discharges of legacy wastewater equal to BPT limitations for fly ash transport water, bottom ash transport water, and low volume waste sources, the final rule does not establish PSES for legacy wastewater (see Section 8.3.8). TSS and the pollutants it represents are effectively treated by, and thus do not pass through, POTWs.

[84] Whereas the final rule establishes BAT limitations on TSS in fly ash and bottom ash transport water, FGMC wastewater, FGD wastewater, and gasification wastewater for small generating units and oil-fired generating units, TSS and the pollutants that they represent do not pass through POTWs.

8.6 PSNS

After considering all of the relevant factors and technology options described in Section 7, as well as public comments, as was the case for NSPS, EPA selected the Option F technologies as the basis for PSNS in the ELG. As a result, the final PSNS establish:

- Standards on arsenic, mercury, selenium, and TDS in FGD wastewater, based on evaporation.
- A zero discharge standard on all pollutants in bottom ash transport water, based on dry handling or closed-loop systems.
- A zero discharge standard on all pollutants in FGMC wastewater, based on dry handling.
- Standards on mercury, arsenic, selenium, and TDS in gasification wastewater, based on evaporation technology.
- Standards on mercury and arsenic in combustion residual leachate, based on chemical precipitation.

All the technology bases for the final PSNS are the same as those described for the final NSPS. The final rule also maintains the previously established zero discharge PSNS on discharges of fly ash transport water, based on dry handling. As with the final NSPS, this rule establishes the same PSNS for oil-fired generating units and small generating units as for all other new sources.

EPA selected the Option F technologies as the basis for PSNS for the same reasons that EPA selected the Option F technologies as the basis for NSPS (see Section 8.4). EPA's record demonstrates that the technologies described in Option F are available and demonstrated, and Option F does not pose a barrier to entry and has acceptable non-water quality environmental impacts, including energy requirements (see Section 12). EPA rejected other options for PSNS for the same reasons that the Agency rejected other options for NSPS. And, as with the final PSES, EPA determined that the final PSNS prevent pass-through of pollutants from POTWs into receiving streams and also help control contamination of POTW sludge.

8.7 ANTICIRCUMVENTION PROVISION

The final rule establishes one of the three anti-circumvention provisions that EPA proposed. The one anti-circumvention provision that EPA decided to establish applies only for existing sources to those wastestreams for which this rule established zero discharge limitations or standards. In general, this provision prevents steam electric power plants from circumventing the final rule by moving effluent produced by a process operation for which there is an applicable zero discharge effluent limitation or standard to another plant process operation for discharge.[85] EPA determined it was appropriate to include this provision in the final rule to make clear that, just because a wastestream that is subject to a zero discharge limitation or standard is moved to another plant process, it does not mean that the wastestream ceases being subject to the

[85] The anti-circumvention provision applies only to limitations and standards established in this final rule. It does not apply to limitations and standards promulgated previously.

applicable zero discharge limitation or standard. For example, using fly ash or bottom ash transport water as makeup water for a cooling tower does not relieve a plant of having to meet the zero discharge limitations and standards for fly ash and bottom ash transport water. EPA encourages the reuse of wastewater where appropriate, but not to the extent that it undermines the zero discharge effluent limitations and standards in this rule. Plants are free to reuse their wastewater, so long as the wastewater ultimately complies with the final limitations and standards.

Some public commenters stated that zero discharge effluent limitations and standards for fly ash and bottom ash transport water, together with this anti-circumvention provision, would prohibit water reuse and prevent water use reduction at steam electric power plants. In general, EPA disagrees with these commenters. Most plants will choose to comply with the requirements for ash transport water by operating either a dry or closed-loop wet-sluicing system to handle their fly and bottom ash, which will eliminate or substantially reduce the amount of water they currently use in the traditional wet-sluicing system. To the extent that a plant currently uses (or was considering using) ash transport water, such as the effluent from an impoundment, as makeup water for processes such make-up cooling water and would be precluded from doing so because of the anti-circumvention provision in this rule, the plant could merely switch to an alternate source for the makeup water, such as the water that was (prior to implementing the zero discharge requirement for ash transport water) used to sluice fly ash or bottom ash to the impoundment. In other words, the volume of water that is currently used to sluice ash to an impoundment and subsequently reused as makeup water would no longer be needed to sluice the ash and could instead be directly used as makeup water for the cooling water system or other processes. Because of this, the zero discharge limitations in this rule will not lead to a net increase at the plant and in fact could result in a decrease in water use. Lastly, a plant is free to reuse ash transport water, and would be in compliance with the anti-circumvention provision, so long as it is used in a process that does not ultimately result in a discharge.

There is one particular type of plant practice that the final rule's anti-circumvention provision does not apply to. Many industry commenters noted that they use ash transport water in their FGD scrubber. They stated that this practice is preferable to using a fresh water source and allows for an overall reduction in source water withdrawals. They further stated that, under the final rule, any wastewater that passes through the scrubber would undergo significant treatment in order to meet the final FGD wastewater limitations and standards. EPA agrees, in part, with these comments. As explained above, EPA does not agree that using wastewater from one industrial process as makeup water in another industrial process necessarily results in a net reduction in water withdrawals. EPA does agree, however, that using wastewater from an industrial process as makeup water in another industrial process may be preferable to using a fresh water source. EPA is mindful of the CWA's pollutant discharge elimination goal, but also wants to promote opportunities for water reuse. Furthermore, as explained in Section 4.5, EPA recognizes the extensive changes in this industry, and it wants to provide flexibility to plants in managing their wastewater and operations, as well as preserve the ability of plants to retain existing approaches where it is consistent with the CWA's goals. While EPA would not choose to promote these considerations where it resulted in no further progress toward the pollutant discharge elimination goal of the Act, in the case of using ash transport water in an FGD scrubber, since any resulting wastewater discharges would still be required to meet BAT or PSES requirements based on either chemical precipitation plus biological treatment or chemical precipitation plus evaporation under this final rule, EPA decided not to apply the anti-circumvention provision to this particular practice.

This rule does not establish an anti-circumvention provision that would have required internal monitoring to demonstrate compliance with certain numeric limitations and standards. Some public commenters argued that the proposed provision was unduly restrictive, and they stated that EPA already has authority to accomplish the goal of this particular provision, which is to ensure that wastestreams are being treated rather than simply diluted. EPA agrees with these commenters and thus decided that existing rules, along with the guidance in TDD Section 14, provide appropriate flexibility to steam electric power plants to combine wastestreams with similar pollutants and treatability, while adequately addressing EPA's concern that plants meet the effluent limitations and standards in this rule through treatment and control strategies, rather than through dilution. Furthermore, some commenters raised concerns that the proposed provision would be a disincentive for plants to internally reuse the treated wastewater within the plant, particularly when the reuse eliminates the discharge of the wastewater. For example, they stated that some steam electric power plants might opt to use a wet scrubber's FGD wastewater as reagent make-up for a new dry scrubber in an integrated design which would essentially evaporate the wet FGD wastewater. EPA notes that plants that internally reuse wastestreams for which EPA is establishing numeric limitations and standards (*e.g.*, FGD wastewater) in a way that completely prevents discharge of that wastestream would not be subject to the numeric limitations and standards because they do not discharge the wastewater. EPA is aware of at least one plant that elected to take such an approach as an alternative to meeting NPDES permit limitations by installing wastewater treatment technology [ERG, 2015i]. In general, EPA supports such approaches because they result in further progress towards achieving the pollutant discharge elimination goal of the CWA. Moreover, such approaches are favored because they reduce overall water intake needs.

This rule also does not establish an anti-circumvention provision that would have required permittees to use EPA-approved analytical methods that are sufficiently sensitive to provide reliable, quantified results at levels necessary to demonstrate compliance with the final effluent limitations and standards because another recently promulgated rule already accomplishes this. As public commenters pointed out, EPA was conducting a rulemaking on that topic; and, in August 2014, EPA published a rule requiring the use of sufficiently sensitive analytical test methods when completing any NPDES permit application. Moreover, the NPDES permit authority must prescribe that only sufficiently sensitive methods be used for analyses of pollutants or pollutant parameters under an NPDES permit where EPA has promulgated a CWA method for analysis of that pollutant. That rule clarifies that NPDES applicants and permittees must use EPA-approved analytical methods that are capable of detecting and measuring the pollutants at, or below, the applicable water quality criteria or permit limits.

8.8 OTHER REVISIONS

This section describes other revisions to the steam electric power generating ELGs related to corrections of typographical errors and further clarifications on the applicability.

8.8.1 Correction of Typographical Error for PSNS

As EPA proposed to do, EPA corrects a typographical error in the previously established PSNS for cooling tower blowdown. As is clear from the development document for the 1982 rulemaking, as well as the previously promulgated NSPS for cooling tower blowdown, EPA inadvertently omitted a footnote in the table that appears in 40 CFR 423.17(d)(1). The footnote reads "No detectable amount," and it applies to the effluent standard for 124 of the 126 priority pollutants contained in chemicals added for cooling tower maintenance. (See *Development Document for Final Effluent Guidelines, New Source Performance Standards and Pretreatment Standards for the Steam Electric Power Generating Point Source Category*, Document No. EPA 440/1-82/029. November 1982.)

8.8.2 Clarification of Applicability

The final rule contains three minor modifications to the wording of the applicability provision in the steam electric power generating ELGs to reflect EPA's longstanding interpretation and implementation of the rule. These revisions do not alter the universe of generating units regulated by the ELGs, nor do they impose compliance costs on the industry. Instead, they remove potential ambiguity in the regulations by revising the text to more clearly reflect EPA's long-standing interpretation.

First, the applicability provision in the previous ELGs stated, in part, that the ELGs apply to "an establishment primarily engaged in the generation of electricity for distribution and sale . . . ." (40 CFR 423.10). The final rule revises that phrase to read "an establishment whose generation of electricity is the predominant source of revenue or principal reason for operation . . . ." The final rule thus clarifies that certain plants, such as generating units owned and operated by industrial facilities in other sectors (*e.g.*, petroleum refineries, pulp and paper mills) that have not traditionally been regulated by the steam electric ELGs, are not within the scope of the ELGs. In addition, the final rule clarifies that certain municipally-owned plants that generate and distribute electricity within a service area (such as distributing electric power to municipally-owned buildings), but which use accounting practices that are not commonly thought of as a "sale," are subject to the ELGs. Such plants have traditionally been regulated by the steam electric power generating ELGs.

Second, the final rule clarifies that fuels derived from fossil fuel are within the scope of the ELGs. The previous ELGs stated, in part, that they apply to discharges related to the generation of electricity "which results primarily from a process utilizing fossil-type fuels (coal, oil, or gas) or nuclear fuel . . . ." (40 CFR 423.10). Because a number of fuel types are derived from fossil fuels themselves, the final rule explicitly mentions and gives examples of such fuels. Thus, the final rule reads that the ELGs apply to discharges resulting from the operation of a generating unit "whose generation results primarily from a process utilizing fossil-type fuel (coal, oil, or gas), fuel derived from fossil fuel (*e.g.*, petroleum coke, synthesis gas), or nuclear fuel . . . ."

Third, the final rule clarifies the applicability provision to reflect the current interpretation that combined cycle systems are subject to the ELGs. The ELGs apply to electric generation processes that utilize "a thermal cycle employing the steam water system as the thermodynamic medium." (40 CFR 423.10). EPA's longstanding interpretation is that the ELGs apply to discharges from all electric generating processes with at least one prime mover that utilizes steam (and that meet the other applicability factors in 40 CFR 423.10). Combined cycle systems, which are generating units composed of one or more combustion turbines operating in conjunction with one or more steam turbines, are subject to the ELGs. The combustion turbines for a combined cycle system operate in tandem with the steam turbines; therefore, the ELGs apply to wastewater discharges associated with both the combustion turbine and steam turbine portions of the combined cycle system. The final rule, therefore, clarifies that "[t]his part applies to discharges associated with both the combustion turbine and steam turbine portions of a combined cycle generating unit."

8.9 Non-Chemical Metal Cleaning Waste

EPA proposed to establish BAT/NSPS/PSES/PSNS requirements for non-chemical metal cleaning wastes equal to previously established BPT limitations for metal cleaning wastes.[86] EPA based the proposal on EPA's understanding, from industry survey responses, that most steam electric power plants manage their chemical and non-chemical metal cleaning wastes in the same manner. Since then, based in part on public comments submitted by industry groups, the Agency has learned that plants refer to the same operation using different terminology; some classify non-chemical metal cleaning waste as such, while others classify it as low volume waste sources. Because the survey responses reflect each plant's individual nomenclature, the survey results for non-chemical metal cleaning wastes are skewed. Furthermore, EPA does not know the nomenclature each plant used in responding to the survey, so it has no way to adjust the results to account for this. Consequently, EPA does not have sufficient information on the extent to which discharges of non-chemical metal cleaning wastes occur, or on the ways that industry manages their non-chemical metal cleaning wastes. Moreover, EPA also does not have information on potential best available technologies or best available demonstrated control technologies, or the potential costs to industry to comply with any new requirements. Due to incomplete data, some public commenters urged EPA not to establish BAT limitations for non-chemical metal cleaning wastes in this final rule. Ultimately, EPA decided that it does not have enough information on a national basis to establish BAT/NSPS/PSES/PSNS requirements for non-chemical metal cleaning wastes. The final rule, therefore, continues to "reserve" BAT/NSPS/PSES/PSNS for non-chemical metal cleaning wastes, as the previously promulgated regulations did.[87]

By reserving limitations and standards for non-chemical metal cleaning waste in the final rule, the permitting authority must establish such requirements based on BPJ for any steam electric power plant discharging non-chemical metal cleaning wastes. As part of this determination, EPA expects that the permitting authority would examine the historical permitting record for the particular plant to determine how discharges of non-chemical metal cleaning waste

[86] Under the structure of the previously promulgated regulations, non-chemical metal cleaning wastes are a subset of metal cleaning wastes.

[87] As part of its proposal to establish new BAT/PSES/NSPS/PSNS requirements for non-chemical metal cleaning waste equal to BPT limitations for metal cleaning waste, EPA also proposed an exemption for certain discharges of non-chemical metal cleaning waste, which would be treated as low volume waste sources. Because the final rule does not establish these new requirements, EPA also did not finalize the proposed exemption.

had been permitted in the past, including whether such discharges had been treated as low volume waste sources or metal cleaning waste.

8.10 Best Management Practices

EPA proposed to include BMPs in the ELGs that would require plant operators to conduct periodic inspections of active and inactive surface impoundments to ensure their structural integrity and to take corrective actions where warranted. The proposed BMPs were largely similar to those proposed for the CCR rule, except for the closure requirements. EPA took comments on whether establishment of BMPs was more appropriate under the authority of the Resource Conservation and Recovery Act (RCRA) or the CWA. While some commenters asked EPA to establish BMPs in the final rule, many others urged EPA not to do so, arguing that BMPs are better suited for the CCR rule. Because EPA promulgated BMPs in the CCR rule, to avoid unnecessary duplication, the final rule does not establish BMPs.

8.11 References

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SECTION 9
ENGINEERING COSTS

This section presents EPA's methodology to determine incremental capital and operation and maintenance (O&M) costs for the steam electric power generating industry to comply with the final rule. For more specific information on EPA's cost methodology, see EPA's *Incremental Costs and Pollutant Removals for Final Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category* [U.S. EPA, 2015a].

Section 9.1 describes EPA's general approach for estimating incremental compliance costs for the steam electric effluent limitations guidelines and standards (ELGs). Section 9.2 describes the basis for the compliance costs for each wastestream and technology option. Section 9.3 describes the methodology EPA used to estimate costs for the steam electric power generating industry to achieve the limitations and standards based on the technology options (described in Section 8 of this report). Section 9.3 also presents information on the specific cost elements included in EPA's methodology and the criteria EPA used to identify plants that would likely incur compliance costs. Section 9.4 describes the development of the data inputs, outputs, and model used to estimate the compliance costs. Section 9.5 presents EPA's methodologies for estimating those components of compliance costs that are applicable to more than one of the treatment technologies evaluated. Sections 9.6, 9.7, 9.8, and 9.9 summarize the technology options assessed in the cost analysis and the results for flue gas desulfurization (FGD) wastewater, fly ash and bottom ash transport water, combustion residual leachate, and gasification wastewater, respectively.[88]

9.1 INTRODUCTION

EPA estimated plant-specific costs to control discharges at existing steam electric power plants to which the ELGs apply (existing sources). For all applicable wastestreams, EPA assessed the operations and treatment system components in place at a given plant in the baseline, identified equipment and process changes that the plant would likely make to meet ELGs, and estimated the incremental cost to implement those changes.[89] While plants are not required to implement the specific technologies that form the basis for the options considered for the final rule EPA often calculates the cost for plants to implement these technologies to estimate incremental compliance costs to industry associated with the ELGs. As appropriate, EPA also accounted for cost savings associated with these equipment and process changes (*e.g.*, avoided costs to manage surface impoundments). EPA thus derived incremental capital and O&M costs at the plant level for control of each wastestream using the technology that forms the basis for

[88] EPA did not estimate incremental compliance costs for flue gas mercury control (FGMC) wastewater because, as described in Section 9.2.6, EPA determined that all plants operating sorbent injection systems to remove mercury from the flue gas already operate dry handling systems, operate wet systems that do not discharge, or have the capability to operate dry handling systems.

[89] Baseline operations and treatment system components characterize current plant operations as determined based on responses to the *Questionnaire for the Steam Electric Power Generating Effluent Guidelines* and other publicly available information including comments to the proposed rulemaking, vendor information, and data from operating companies.

the final rule. All cost components described and presented in the section for existing sources represent EPA's estimated incremental capital and O&M costs.

EPA estimated the costs on a per plant basis and then summed or otherwise escalated the plant-specific values to represent industry-wide compliance costs (see *Regulatory Impact Analysis for Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (EPA-821-R-15-004)*). Calculating costs on a per plant basis allowed EPA to account for differences in plant characteristics such as types of processes used, wastewaters generated and their flows/volumes and characteristics, and wastewater controls in place (*e.g.*, best management practices (BMPs) and end-of-pipe treatment).

EPA estimated the costs to steam electric power plants – whose primary business is electric power generation or related electric power services – of complying with the ELGs (EPA also estimated the costs for complying with several other regulatory options considered, but not selected, for the final rule.) EPA evaluated the costs of the ELGs on all plants currently subject to the existing ELGs.[90] Some aspects of the ELGs (*e.g.*, applicability changes) would likely not lead to increased costs to complying plants. Other aspects of the ELGs would likely increase costs for a subset of complying plants. These are plants that generally generate the wastestreams for which EPA is promulgating new effluent limitations or standards. This section describes the detailed costing evaluation EPA performed for these plants that may incur compliance costs associated with the rulemaking.

Where the final rule does not establish new requirements for existing facilities or establishes the best available technology economically achievable (BAT) based on previously established best practicable control technology current available (BPT) limitations, there are no incremental costs to comply with the final rule. For example, EPA did not estimate incremental compliance costs for existing facilities to comply with the final BAT limitations and standards for combustion residual leachate or for oil-fired generating units and small generating units with a capacity of 50 megawatts (MW) or less.

EPA estimated compliance costs associated with each of the regulatory options from data collected through the *Questionnaire for the Steam Electric Power Generating Effluent Guidelines* (Steam Electric Survey) responses, site visits, sampling episodes, and from individual power plants and equipment vendors. EPA used this information to develop computerized cost models for each of the technologies that form the basis of the regulatory options. EPA used these models to calculate plant-specific compliance costs for all power plants that the information suggests would incur costs to comply with one or more requirements associated with the regulatory options. Additionally, EPA calculated plant-specific costs for other scenarios as well. Specifically, EPA calculated plant-specific costs that take into account expected plant operation changes resulting from the Resource Conservation and Recovery Act (RCRA) requirements (*i.e.*,

[90] Based on the Steam Electric Survey responses, Internet searches, articles, and data provided by the industry, EPA removed the following types of plants, or steam electric generating units, from the analysis as they were considered outside the applicability of the rule or would be by the time the final rule is promulgated: plants, or steam electric generating units, expected to be retired by December 31, 2023; and plants, or steam electric generating units, converting to non-fossil fuel sources (*e.g.*, natural gas, municipal solid waste) by December 31, 2023. This approach is reasonable given that EPA identified only one plant closing before 2023 for which the assumed technology implementation year would precede the announced retirement or conversion year (by one year).

coal combustion residual (CCR) rule) and plant-specific retirements resulting from the Clean Power Plan (CPP). EPA's cost estimates include the following key cost components:

- Capital costs (one-time costs).
- Annual O&M costs (which are incurred every year).
- Other one-time or recurring costs.

Capital costs comprise the direct and indirect costs associated with purchasing, delivering, and installing pollution control technologies. Capital cost elements are specific to the industry and commonly include purchased equipment and freight, equipment installation, buildings, site preparation, engineering costs, construction expenses, contractor's fees, and contingency. Annual O&M costs comprise all costs related to operating and maintaining the pollution control technologies for a period of 1 year. O&M costs are also specific to the industry and commonly include costs associated with operating labor, maintenance labor, maintenance materials (routine replacement of equipment due to wear and tear), chemical purchase, energy requirements, residual disposal, and compliance monitoring. In some cases, the technology options may also result in recurring costs that are incurred less frequently than annually (*e.g.*, 3-year recurring costs for equipment replacement) or one-time costs other than capital investment (*e.g.*, one-time engineering costs).

9.2 STEAM ELECTRIC TECHNOLOGY OPTION COST BASES

The following sections describe the technologies used as the basis for estimating compliance costs for each wastestream and technology option. Section 8 identifies the technology options considered for this rulemaking, while Section 7 describes them in detail.

9.2.1 FGD Wastewater

EPA estimated compliance costs for plants to treat FGD wastewater using one of the following two technology options: chemical precipitation or chemical precipitation followed by biological treatment.

EPA also estimated compliance costs for plants to treat FGD wastewater using chemical precipitation followed by evaporation. As described in "Plant-Specific Compliance Cost Estimates for the Treatment of FGD Wastewater with Chemical Precipitation Followed by Evaporation", EPA determined that the total industry costs for existing sources would be too high, nearly $1 billion more expensive on an annual basis than the cost of limitations based on chemical precipitation followed by biological treatment [ERG, 2015f]. EPA did not evaluate chemical precipitation followed by evaporation further as a treatment technology for existing sources and therefore, this treatment technology for FGD wastewater is not discussed further in this section.

For the chemical precipitation system, EPA included costs for the plants to install and operate the following:

- Equalization tank to hold and store the wastewater.
- Reaction tanks for the addition of lime, organosulfide, ferric chloride, and polymers.

- Solids-contact clarifier to remove suspended solids.
- Gravity sand filter to reduce solids.
- Effluent storage tank.
- Mercury analyzer.

Additionally, EPA included costs for a sludge holding tank, filter presses to dewater the solids collected in the clarifier, and costs to transport and dispose of the resulting solids in a landfill. The costs also include all ancillary equipment and the associated O&M costs for the system.

For the chemical precipitation followed by biological treatment system, EPA included all the costs described above for the chemical precipitation system, but it also included costs for the following:

- Anoxic/anaerobic biological treatment system (two stages).
- Heat exchanger (for plants in certain geographic locations).
- Oxidation-reduction potential (ORP) monitor.
- Chemical addition system for ORP control.
- Denitrification treatment system (for plants with nitrate/nitrite concentrations greater than 100 parts per million (ppm)).

EPA also included costs to transport and dispose of additional solids collected in the biological system. The costs include all ancillary equipment and the associated O&M costs for the system.

9.2.2 Fly Ash Transport Water

EPA estimated compliance costs for plants discharging fly ash transport water to convert from a wet ash handling system to a dry vacuum fly ash handling system. For the conversion to the dry vacuum fly ash handling system, EPA included costs for the plants to install and operate the following[91]:

- Mechanical exhausters.
- Piping and valves.
- Filter-receivers.
- Silo(s) (steel or concrete).
- Pugmills.

For generating units determined to require only redundant conveyance or backup storage equipment to handle all fly ash dry, EPA estimated capital costs to install the following (based on the type of existing dry fly ash handling system for the generating unit):

[91] For each generating unit discharging fly ash transport water, EPA determined that the plants would likely continue to use the existing valves and branch lines underneath the fly ash collection hoppers, associated with the existing wet-sluicing system, but the plant would require new valves and piping to convey the dry fly ash to the silo(s).

- Mechanical exhausters.
- Filter-receivers.
- Silo(s) (steel or concrete).
- Pugmills.

Additionally, EPA included capital and O&M costs to transport and dispose of the moisture conditioned fly ash in a landfill, and costs associated with water trucks around the landfill for dust suppression.

9.2.3 Bottom Ash Transport Water

EPA estimated compliance costs for plants discharging bottom ash transport water to convert from a wet ash handling system to a dry or closed-loop bottom ash handling system (*i.e.*, a system that eliminates the discharge of bottom ash transport water). For each generating unit discharging bottom ash transport water, EPA estimated costs associated with converting to a dry bottom ash handling system in the form of a mechanical drag system (MDS) and costs associated with converting to a closed-loop bottom ash handling system in the form of a remote MDS.

For the MDS, EPA included the costs to demolish the bottom of the boiler and install and operate an MDS (at the bottom of the boiler) and a semi-dry silo.

The MDS design does not include operation as a closed-loop system (*i.e.*, the water leaving the system with the bottom ash does not need to be collected, cooled, and returned to the system), therefore eliminating the need for a heat exchanger.[92]

For the remote MDS, EPA included the costs to install and operate the following:

- Remote MDS (away from the boiler).
- Sump.
- Recycle pumps.
- Chemical feed system.[93]
- Semi-dry silo.

[92] The MDS does not need to operate as a closed-loop system because it does not use water as the transport mechanism to remove the bottom ash from the boiler; the conveyor is the transport mechanism. Therefore, any water leaving with the bottom ash does not fall under the definition of "bottom ash transport water," but rather, is a low volume waste.

[93] Because the remote MDS uses water as the transport mechanism, all water removed from the system must be reused without discharge to meet the zero discharge effluent limitations for bottom ash transport water. EPA included costs for a chemical feed system to control pH, should that become necessary to prevent scaling within the system. Information in the record indicates that few, if any, plants are likely to need to use such systems. However, because EPA could not conclusively determine that none of the plants would need the chemical feed system to control pH of the recirculating system, nor which of the plants would be likely to need the system; costs were included for all plants. This likely overestimates the compliance costs for most plants; however, the cost for chemical addition is relatively small in relation to other costs for the remote MDS.

EPA also included capital and O&M costs for transporting and disposing of all bottom ash to a landfill for both the MDS and remote MDS.

For all generating units discharging bottom ash transport water, EPA estimated costs for the generating unit to convert to either an MDS or a remote MDS. EPA evaluated both of these technologies because the MDS is the most commonly used dry handling/closed-loop system operating in the industry, but EPA is aware that not all generating units have enough space underneath the boiler to accommodate an MDS conversion. While the remote MDS is not as common as the MDS, EPA has determined that it can be installed at all power plants. Therefore, EPA determined that plants will be able to install one of the two technologies to meet the zero discharge requirements. Where plants/companies provided data identifying space constraints associated with an MDS conversion, EPA used the cost estimates for the remote MDS conversion only for those specific plants. For the remainder, EPA used the lower of the two costs.

EPA also identified several plants that operate bottom ash wet handling systems predominantly as closed-loop systems. These plants did not discharge bottom ash transport water in 2009. However, based on data in responses to the Steam Electric Survey, EPA determined that these plants have the ability to discharge bottom ash transport water from emergency outfalls. Because of the potential to discharge bottom ash transport water, EPA estimated costs for these plants to hire a consultant to eliminate the bottom ash transport water emergency outfall and install and operate a chemical feed system.

9.2.4 <u>Combustion Residual Leachate</u>

For Regulatory Option E, EPA estimated compliance costs for plants to treat combustion residual leachate with a chemical precipitation system. For the remaining regulatory options (A through D) requirements for combustion residual leachate based on previously established BPT limitations. Therefore, EPA estimated there will be no compliance costs in the final rule associated with control of discharges of combustion residual leachate for Regulatory Options A, B, C, and D.To estimate the compliance costs for plants that generate landfill leachate, EPA included the same cost components as described in Section 9.2.1 for chemical precipitation treatment of FGD wastewater.

Plants that generate leachate from surface impoundments containing combustion residuals will likely use a different approach than installing the technology basis to comply with requirements based on the chemical precipitation technology option. As described in Section 7.4, 40 percent of plants generating leachate from impoundments containing combustion residuals recycle the leachate back to the impoundment from which it was collected. Additionally, some plants use the combustion residual impoundment leachate for dust control at a landfill or to moisture condition ash transported to a landfill. Based on these data, EPA determined that plants would likely comply with the effluent limitations and standards for discharges of combustion residual leachate discharges by recycling the leachate back to the impoundment where it was generated or use the leachate in a process that does not result in discharge to surface water (*e.g.*, moisture conditioning) instead of installing the technology option to treat and discharge the wastewater because it is a less expensive alternative. EPA does not consider impoundment leachate that is returned back to the impoundment where it was generated as leachate because the wastewater never leaves the impoundment system. In this case, EPA still considers the wastewater to be the wastewater that enters the impoundment (*e.g.*, fly ash transport water, low volume wastewater sources). There would be no (or negligible) costs associated with recycling the combustion residual impoundment leachate back to the impoundment because the plant will either: 1) use the existing pump that transfers the leachate to a separate location to pump it back to the impoundment; or 2) install a pump to transfer the leachate to the impoundment. In the second case, the costs would likely be offset because the plant would no longer need to operate a separate impoundment (or other treatment system) to treat the leachate to meet the previously established BPT effluent limitations prior to its discharge. Therefore, EPA determined that there are no compliance costs associated with control of discharges of combustion residual leachate from surface impoundments under any of the regulatory options considered. Therefore, where this section further addresses the costing methodology for combustion residual leachate associated with the chemical precipitation technology option, it refers to the costs associated with treating combustion residual leachate from landfills.

9.2.5 Gasification Wastewater

EPA identified three currently operating integrated gasification combined-cycle (IGCC) units in the United States discharging gasification wastewater.[94] Each of these plants operates the evaporation system that is the technology basis for the ELGs for gasification wastewater.[95] Therefore, because all the plants are currently operating the BAT system, EPA determined that there will be no capital compliance costs associated with the control of discharges of gasification wastewater. EPA estimated the O&M costs for these three plants related to compliance monitoring.

9.2.6 Flue Gas Mercury Control Wastewater

As described in Section 7.5, there are approximately 62 plants with at least one activated carbon injection (ACI) system. Of these, only four (two with current systems and two with planned systems) report handling the FGMC waste using a wet-sluicing system. However, only one of these four plants discharges FGMC wastewater, and that one plant collects the FGMC waste with the fly ash in the primary particulate control system and already has the capability to dry handle both the FGMC waste and fly ash. Therefore, EPA estimated there will be no compliance costs in the final rule associated with control of discharges of FGMC wastewater.

9.3 STEAM ELECTRIC COMPLIANCE COST METHODOLOGY

EPA developed a cost methodology to estimate plant-level compliance costs for existing and new sources using data collected from the Steam Electric Survey, site visits, and sampling episodes. EPA also solicited data from vendors of various wastewater treatment technologies and

[94] EPA is aware of the Mississippi Power Company's Kemper County Energy Facility, which is a new IGCC plant that is currently under construction. According the operating companies website, the plant will not discharge any gasification wastewater and, therefore, the plant will not incur any costs to comply with the ELGs.

[95] EPA evaluated all plants operating the evaporation system to determine if any of these plants would require additional treatment in order to comply with the ELGs. See "Effluent Limitations for FGD Wastewater, Gasification Wastewater, and Combustion Residual Leachate for the Final Effluent Limitations Guidelines and Standards for the Steam Electric Rulemaking" for further details on this evaluation [U.S. EPA, 2015b].

ash handling operations to estimate plant-level compliance costs. The estimated costs are incremental costs to account for only the additional costs beyond those the plant already incurs, or would incur as a new source, to comply with the final regulations.

As a first step in estimating costs associated with new limitations or standards for discharges from a particular generating unit at an existing steam electric plant (*i.e.*, existing sources), EPA used the plant's Steam Electric Survey response and other industry-submitted data to determine if the wastestreams it discharges may be subject to new requirements under a regulatory option considered for the ELGs. Then, for each wastestream that may be subject to new requirements for a regulatory option, EPA reviewed the Steam Electric Survey response, available sampling data, and industry long-term self-monitoring data for the plant to determine if its existing practices would lead to compliance with the new or revised limitations or standards (*e.g.*, the plant currently uses the technology option for a given wastestream). In some cases, EPA determined that a particular plant will incur only minimal compliance costs (*e.g.*, compliance monitoring, ORP monitors) for a particular wastestream. For all other applicable wastestreams, EPA assessed the operations and treatment system components in place at the plant, identified components that the plant would likely install to comply with the final rule, and estimated the cost to install and operate those components. As appropriate, EPA also accounted for expected reductions in the plant's costs associated with its current operations or treatment systems that would no longer be needed as a result of installing and operating the technology bases (*e.g.*, avoided costs to manage surface impoundments). For plants that may already have certain components installed, EPA compared certain key operating characteristics, such as chemical addition rates, to determine if additional costs (*e.g.*, chemical costs) were warranted.

For example, for an existing source to comply with Option D, EPA estimated compliance costs for a plant that currently sluices fly ash to an ash impoundment and subsequently discharges that fly ash transport water. In this case, EPA estimated the cost for the plant to convert its fly ash handling system to a dry vacuum system and determined that certain components of its existing system would continue to be used following the conversion.[96] EPA included costs for additional equipment, such as vacuum systems and silos, to handle and store the dry fly ash. EPA also included additional transportation and landfill disposal costs, and cost savings for managing less waste through the ash impoundment(s).

As another example, for an existing source to comply with Option D, EPA estimated compliance costs for a plant that currently treats its FGD wastewater in a chemical precipitation system prior to discharge. In this case, EPA evaluated the following: 1) whether the chemical precipitation system design basis includes equalization with 24-hour residence time, 2) if the plant had an equivalent number and/or type of reaction tanks, and 3) if the plant already had in place components such as chemical feed systems, solids contact clarifier, sand filter, effluent and sludge holding tanks, sludge filter presses, and pumps. If the plant had any of these components in place, EPA did not include that cost in its compliance cost estimate. EPA also evaluated whether chemical addition costs should be factored in based on the plant's reported chemical

[96] Converting a steam electric generating unit from wet to dry fly ash handling requires new equipment to pneumatically convey the ash; however, ash handling vendors stated that for dry vacuum retrofits, the existing hopper equipment and branch lines can be retained and reused.

addition and dosages, and estimated the costs for installing and operating the biological treatment stage.

EPA also evaluated the additional transportation and landfill operations that might be appropriate to dispose of the additional solid waste generated (FGD sludge, fly ash, bottom ash) from implementing the technology options. EPA estimated disposal costs based on whether or not the plant reported an on-site combustion residual landfill.

For each plant, EPA calculated compliance costs for all applicable technology options and then calculated the total capital, O&M, and other one-time or recurring costs for the six main regulatory options, presented in Table 8-1. For more information on the compliance cost methodology, see EPA's *Incremental Costs and Pollutant Removals for Final Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category* [U.S. EPA, 2015a].

9.4 STEAM ELECTRIC COST MODEL

EPA calculated the industry incremental compliance cost estimates by developing a computer-based cost model containing the following main components:

- Input Data.
- Industry Assumptions/Factors.
- Technology Cost Modules.
- Model Outputs.

Input data include relevant plant-specific information, such as identifying which wastewaters are discharged from each plant, plant processes, wastewater flow rates, production data, and existing pollution control technologies. Industry assumptions and factors are general values and factors that are not plant-specific and are applicable to the entire industry. These include constants and coefficients used in the cost calculations such as equipment design basis (used for equipment sizing, for example hydraulic residence time), materials of construction, equipment capacity (accounts for maximum design capacity as compared to typical operating conditions), equipment redundancy, transport distance for equipment and supplies, transport mode and capacity, and cost indices (used to adjust cost data from different years to a common base year). Technology cost modules use the plant-specific input data and industry assumptions/factors to calculate costs for a specific cost component (technology or technology component) for each applicable wastestream for each plant and each regulatory option. Finally, reporting programs generate the model outputs. These reporting programs combine the applicable cost components to calculate plant-level capital and O&M costs (and any necessary one-time and/or recurring costs) for each regulatory option, and to sum or otherwise escalate these plant-level costs to calculate total industry capital and O&M costs by regulatory option. Table 9-1 presents the different technology cost modules that compose the technology options. Each technology option incorporates technology-specific and global assumptions and factors to calculate the compliance costs (*e.g.*, the model outputs).

Table 9-1. Technology Costs Modules Used to Estimate Compliance Costs

Technology Option	Technology Cost Module								
	Chemical Precipitation	Biological Treatment	Evaporation	Dry Fly Ash Handling	Dry Bottom Ash Handling [a]	Compliance Monitoring	Transportation	Disposal	Surface Impoundment Operation Costs
FGD Wastewater Treatment: Chemical Precipitation	✓					✓	✓	✓	✓
FGD Wastewater Treatment: Chemical Precipitation + Biological Treatment	✓	✓				✓	✓	✓	✓
FGD Wastewater Treatment: Chemical Precipitation + Evaporation	✓		✓			✓	✓	✓	✓
Fly Ash: Zero discharge				✓			✓	✓	✓
Bottom Ash: Zero discharge					✓		✓	✓	✓
Leachate Wastewater Treatment: Chemical Precipitation	✓					✓	✓	✓	
Gasification Wastewater: Evaporation [b]						✓			

Note: As described in Section 9.2.6, EPA did not estimate costs for FGMC wastewater.

a – The technology cost module is called the “Dry Bottom Ash Handling” module, but it includes a technology option that is a closed-loop recycle system.

b – The Agency calculated the plant-level gasification wastewater costs separate from the cost model. See Section 9.9.

9.4.1 Input Data to Technology Cost Modules

EPA developed a set of input tables based on information from the Steam Electric Survey responses, site visits, sampling episodes, and other industry provided data. The cost model references the input tables to estimate the appropriate compliance cost for each plant for each technology option. To estimate the plant-level compliance costs for each regulatory option, the cost model estimates compliance costs on a plant basis for each technology option and then sums the various technologies. EPA used plant responses to the Steam Electric Survey, public comments, and other data gathered from vendors and discussions with specific plants to identify the population of plants that discharge wastestreams that may be subject to new or additional limitations or standards [ERG, 2015a]. If the plant does not discharge an applicable wastestream, or if the plant announced plans to retire or alter operations that would eliminate the discharge of an applicable wastestream then EPA set the compliance costs for that wastestream at zero.[97] EPA's estimate of the number of plants and corresponding compliance costs presented in this section reflect these planned retirements and changes in operations that would eliminate the discharge of an applicable wastestream.

EPA coordinated the requirements of the CCR rule and the ELG to avoid establishing overlapping regulatory requirements and to facilitate the implementation of engineering, financial, and permitting activities. For the ELGs, EPA calculated costs, pollutant loadings/removals, non-water quality environmental impacts, environmental assessment, and benefits analyses under two scenarios: one that incorporates changes EPA expects as a result of plants complying with the CCR rule and one that also incorporates changes EPA expects as a result of plants complying with the CPP.[98] To account for the implementation of the CCR rule, EPA updated its population and associated treatment in place to account for the changes in plant operations that EPA projected under the CCR rule (see the description of the CCR Input Table later in this section). All numbers presented in this report reflect the analyses EPA prepared based on the population that accounts for the implementation of the CCR rule. Table 9-2 identifies the number of plants that EPA estimates would incur costs to comply with new or additional effluent limitations or standards for a wastestream under at least one of the evaluated ELG regulatory options. See the appendix of EPA's *Incremental Costs and Pollutant Removals for Final Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category* report for the estimate of what the cost and loadings for the ELG would be in absence of the CCR rule and CPP [U.S. EPA, 2015a].

Similar to the CCR rule, EPA accounted for operational changes expected as part of the CPP. Because only the proposed version of the CPP was available at the time EPA evaluated compliance costs, the Agency estimated compliance costs that account for expected changes

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[97] EPA assumed that there would be no incremental compliance costs attributable to the ELGs for generating units that have announced plans to retire, convert to a non-coal fuel source, or change/upgrade ash handling practices prior to implementation of the final rule. See the *Changes to Industry Profile for Steam Electric Generating Units for the Steam Electric Effluent Guidelines Final Rule* [ERG, 2015d] for a detailed list of these plants and generating units.

[98] EPA also conducted additional analyses to estimate what the costs and pollutant removals for the ELGs would be in the absence of both the CCR rule and CPP. For more details on this sensitivity analysis see the *Incremental Costs and Pollutant Removals for the Final Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* [U.S. EPA, 2015a].

from the proposed CPP rather than the final CPP. As discussed in Section 1.3.3, the CPP rulemaking is focused on cutting carbon pollution from power plants and EPA estimates that some generating units may retire due to the CPP.[99] To account for these closures/retirements, EPA generated a second set of compliance cost estimates where all generating units that are projected by the Integrated Planning Model (IPM) to close/retire due to the CPP were assumed to be retired prior to implementation of the ELGs; therefore, these generating units would not incur any ELG compliance costs. Throughout the remainder of this section, EPA presents compliance cost estimates that do not account for the CPP, followed by estimates that account for the CPP (referred to hereafter as "accounting for CPP"). Table 9-3 adjusts the results shown in Table 9-2, accounting for the projected closures related to the implementation of the CPP.

Table 9-2. Number of Plants Expected to Incur Compliance Costs by Wastestream and Regulatory Option

Regulatory Option	FGD Wastewater	Fly Ash Transport Water	Bottom Ash Transport Water	Combustion Residual Leachate	Gasification Wastewater	FGMC Wastewater	Total [a]
A	87	19	0	0	3	0	100
B	87	19	0	0	3	0	100
C	87	19	78	0	3	0	139
D	87	19	141	0	3	0	181
E	87	19	141	82	3	0	196

a – The number of plants incurring costs is not additive for each regulatory option because some plants may incur costs for multiple wastestreams.

Table 9-3. Number of Plants Expected to Incur Compliance Costs by Wastestream and Regulatory Option, Accounting for CPP

Regulatory Option	FGD Wastewater	Fly Ash Transport Water	Bottom Ash Transport Water	Combustion Residual Leachate	Gasification Wastewater	FGMC Wastewater	Total [a]
A	69	16	0	0	2	0	79
B	69	16	0	0	2	0	79
C	69	16	61	0	2	0	108
D	69	16	103	0	2	0	134
E	69	16	103	60	2	0	145

a – The number of plants incurring costs is not additive for each regulatory option because some plants may incur costs for multiple wastestreams.

[99] The IPM is a multi-regional, dynamic, deterministic linear programming model of the U.S. electric power sector. It provides forecasts of least-cost capacity expansion, electricity dispatch, and emission control strategies for meeting energy demand and environmental, transmission, dispatch, and reliability constraints. IPM can be used to evaluate the cost and emissions impacts of proposed policies to limit emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_x), carbon dioxide (CO_2), hydrogen chloride (HCl), and mercury (Hg) from the electric power sector. The Agency used IPM to predict the industry response to the CPP, which EPA used to identify projected generating unit retirements. The CPP IPM policy run projected 323 generating units to close or retire by 2020.

Each technology cost module includes a set of input tables. These input tables include indicators specifying the type of costs required for each technology option and the plant-specific data used in the cost equations. The following sections describe each of the input tables used in the technology cost modules. See the FGD and Ash Steam Electric Cost Model and the Leachate Steam Electric Cost Model for the specific input tables described below [ERG, 2015b; ERG, 2015c].

FGD Wastewater Flow

For each applicable plant, EPA identified a system-level FGD wastewater flow rate in gallons per day. EPA used the purge rate reported in the Steam Electric Survey as the input value for the FGD technology cost modules. The cost model calculated a plant-level FGD wastewater flow rate by summing the system-level purge rates for each FGD system at each plant. For current FGD systems that did not provide an FGD purge flow value, EPA estimated the purge rate based on the amount of coal burned and the median FGD purge rate per ton of coal burned based on coal type. See Section 4.1.1 of EPA's *Incremental Costs and Pollutant Removals for Final Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category* report for more details on the FGD wastewater flow rate estimation methodology [U.S. EPA, 2015a].[100]

FGD Treatment-In-Place Data

This input table includes data on each plant's current level of treatment for its FGD wastewater. For plants currently treating the FGD wastewater using chemical precipitation, anoxic/anaerobic biological treatment, or evaporation systems, EPA did not estimate compliance costs for the specific pieces of equipment that are already operating at the plant. For example, under Regulatory Option D, if a plant operates a chemical precipitation system to treat FGD wastewater that includes all the steps included as the basis for the technology option other than sulfide precipitation, then EPA included capital costs for the plant to install a reaction tank and sulfide chemical feed system and O&M costs for the amount of sulfide added to the system on a yearly basis, plus the full capital and O&M costs for the biological treatment system. A plant would not incur compliance costs for pieces of equipment that are part of the technology basis and already installed and operating at the plant.

Fly Ash Production Data

For each applicable generating unit, EPA identified generating unit-level wet fly ash production and dry fly ash production in tons per day and days per year, generating unit type, capacity in MW, fly ash transport water flow rate in gallons per day (gpd), and operating days per year. EPA used these values reported in the Steam Electric Survey as input values for the fly

[100] EPA assumed that to achieve the limitations and standards, certain plants with high FGD discharge flow rates (greater than or equal to 1,000 gallons per minute (gpm)) would elect to incorporate flow minimization into their operating practices (by recycling a portion of their FGD wastewater back to the FGD system), where the FGD system metallurgy can accommodate an increase in chlorides. See Section 4.5.4 of EPA's *Incremental Costs and Pollutant Removals for Final Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category* report for more details on the methodology specific to plants with high FGD discharge flow rates [U.S. EPA, 2015a].

ash technology cost module. Because the cost model estimates fly ash compliance cost at the generating unit level, EPA used generating unit-level input values.

EPA also identified generating units with existing dry fly ash handling equipment. Steam electric generating units equipped with only wet fly ash handling systems were estimated to incur the costs for complete conversion of the dry fly ash handling system. Those generating units equipped with both wet and dry fly ash handling capabilities may need only certain additional equipment for them to handle all fly ash dry (*i.e.*, additional vacuum capacity, redundant system conveyance equipment, additional silo capacity, additional unloading equipment, back up silos and/or unloading equipment). EPA evaluated each plant and generating unit to identify the additional equipment that is likely to be needed and included costs for only those pieces of equipment. EPA determined that those generating units that currently use only a dry fly ash handling system do not incur any costs to comply with the ELGs.

Bottom Ash Production Data

For each applicable generating unit, EPA identified generating unit-level wet bottom ash production in tons per day, operating days per year, capacity in MW, generating unit type, bottom ash transport flow rate in gpd, and pond distance. EPA used these values reported in the Steam Electric Survey as input values for the bottom ash technology cost module. Because the cost model estimates bottom ash compliance cost at the generating unit level, EPA used generating-unit-level input values to estimate conversion costs. EPA also identified generating units that recycle the majority of their bottom ash sluice and have emergency outfalls only to estimate bottom ash management costs.

EPA also identified generating units with existing dry or closed-loop bottom ash handling equipment. Steam electric generating units equipped with only wet bottom ash handling systems that discharge bottom ash transport water were estimated to incur the costs for complete conversion to the dry or closed-loop dry bottom ash handling system. EPA determined that those generating units that currently use only a dry or closed-loop bottom ash handling system do not incur any costs to comply with the ELGs. EPA did not identify any generating units equipped with both wet and dry bottom ash handling capabilities.

Impoundment Data

EPA used data from the Steam Electric Survey and plant contacts to identify which plants operate one or more impoundments containing combustion residuals including FGD solids, fly ash, and/or bottom ash.

Landfill Data

EPA used data from the Steam Electric Survey to identify which plants operate on-site active/inactive landfills containing combustion residuals including FGD solids, fly ash, and/or bottom ash as defined by the plant in response to the Steam Electric Survey. Plants without an on-site active/inactive landfill with combustion residuals were identified as off-site landfills.

Combustion Residual Leachate Data

For each landfill identified as collecting and discharging combustion residual landfill leachate, EPA determined the combustion residual landfill leachate volume discharged each year in gallons per day. For those plants that did not report a combustion residual landfill leachate volume in the Steam Electric Survey, EPA estimated a flow rate using data from other plants that did report a combustion residual landfill leachate volume. EPA first determined a median combustion residual landfill leachate discharge rate per acre of landfill containing combustion residuals, based on the responses to the Steam Electric Survey. EPA then multiplied the median value by a plant's reported combustion residual landfill acreage collecting leachate to estimate a flow rate. For those plants that did not report a combustion residual landfill leachate volume or a landfill acreage collecting leachate, EPA estimated the landfill acreage collecting leachate based on the plant's reported total active/inactive landfill acreage and the median ratio of landfill acreage collecting leachate to total active/inactive landfill acreage for those plants that provided both values. Finally, for those plants for which it could not estimate a value using the other two approaches, EPA estimated the combustion residual landfill leachate volume using the median combustion residual landfill leachate volume for all plants reporting a volume.

See Section 4.1.3.1 of EPA's *Incremental Costs and Pollutant Removals for Final Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category* report for more details on the landfill leachate flow rate estimation methodology [U.S. EPA, 2015a].

Final CCR Rule Decisions Input Table

The CCR rule sets requirements for managing impoundments and landfills containing CCRs. Based on the CCR requirements, EPA expects that some plants will alter how they operate their current CCR impoundments, including by undertaking the following potential changes:

- Close the disposal surface impoundment[101] and open a new disposal surface impoundment in its place.
- Convert the disposal surface impoundment to a new storage impoundment.[102]
- Close the disposal surface impoundment and convert to dry handling operations.
- Make no changes to the operation of the disposal surface impoundment.

The CCR rule evaluated these potential operational changes for plants that were identified as operating disposal impoundments based on Energy Information Administration (EIA) data.[103] To be consistent with the methodology used by RCRA, EPA did not evaluate these options for storage impoundments because EPA assumed that storage impoundments will

[101] For the CCR rule, a disposal surface impoundment is generally defined as an impoundment that is not dredged and all CCRs are left in place in perpetuity.

[102] For the CCR rule, a storage impoundment is generally defined as an impoundment that is periodically dredged and has its CCR disposed elsewhere such that it can continue operating indefinitely.

[103] For the CCR rule, if a plant reported active wet CCR disposal in one or more impoundments in its EIA data, EPA considered the largest impoundment (in terms of capacity) at the plant as a CCR disposal impoundment.

operate indefinitely and if a groundwater contamination event occurs, the plant will build a new storage impoundment (but will not convert to dry handling operations).[104]

For this rulemaking, EPA developed a methodology to use the output analysis of the CCR rule to predict which of the four potential operational changes would likely occur at each coal-fired power plant that operates disposal impoundments under the CCR rule. See EPA's *Incremental Costs and Pollutant Removals for Final Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category* report for more details on the methodology EPA used to predict operational changes expected as a result of the CCR rule [U.S. EPA, 2015a]. Using the plant-level decision for operational changes the plant will likely make based on the CCR rule, EPA then applied that decision to each of the evaluated discharged wastestreams for this rule. Finally, EPA evaluated the EIA data to identify which plants were identified under the CCR rule as operating only storage impoundments. While these plants, and wastestreams, are not converting to a storage impoundment as a result of CCR, they already operate a storage impoundment and, therefore, it allowed EPA to classify them in the population as operating storage impoundment for the appropriate wastestreams.

Based on those analyses, EPA generated the CCR Input Table that it used in the costs model and loadings databases to adjust the ELG baseline to account for the CCR rule. Table 9-4 describes how EPA used the classifications in the CCR Input Table to adjust the ELG baseline.

After adjusting the ELG baseline to account for the implementation of the CCR rule, EPA generated the costs, pollutant loadings, non-water quality impacts, environmental assessment, and benefits of the rule. As such, EPA has minimized the degree to which its analyses have potentially "double counted" impacts associated with the ELG and the CCR rule. All numbers presented in this report reflect the updated ELG baseline population accounting for the CCR rule.

Table 9-4. ELG Baseline Changes Accounting for CCR Rule

ELG Wastestream	CCR Rule Decision	Adjustment to ELG Baseline	Effect on ELG Costs [a]	Effect on ELG Loadings [a]
FGD wastewater	New disposal impoundment	No changes	No changes	No changes
	New storage impoundment	No changes	No changes	No changes
	Convert to dry handling	Plant has a BAT chemical precipitation system in place	Plant incurs the following costs: - Mercury analyzer - Compliance monitoring - All biological treatment system costs (including transportation/disposal)	Baseline loadings are based on chemical precipitation treatment in place
	No decision	No changes	No changes	No changes
	New disposal impoundment	No changes	No changes	No changes

[104] For the CCR rule, if a plant did not report active wet CCR disposal in any impoundments in its EIA data, EPA considered all impoundments at the plant to be CCR storage impoundments.

Table 9-4. ELG Baseline Changes Accounting for CCR Rule

ELG Wastestream	CCR Rule Decision	Adjustment to ELG Baseline	Effect on ELG Costs [a]	Effect on ELG Loadings [a]
Fly ash transport water	New storage impoundment	Plant dredges fly ash from impoundment and disposes of it	Plant incurs full conveyance and intermediate storage capital and O&M costs, but does not incur transport/disposal costs	No changes
	Convert to dry handling	Plant operates a dry fly ash handling system for all generating units	Plant incurs no fly ash compliance costs.	Plant has a baseline fly ash loading of zero.
	No decision	No changes	No changes	No changes
Bottom ash transport water	New disposal impoundment	No changes	No changes	No changes
	New storage impoundment	Plant dredges bottom ash from impoundment and disposes of it	Plant incurs full conveyance and intermediate storage capital and O&M costs, but does not incur transport/disposal costs	No changes
	Convert to dry handling	Plant operates a dry bottom ash handling or closed-loop recycle system for all generating units	Plant incurs no fly ash compliance costs.	Plant has a baseline bottom ash loading of zero.
	No decision	No changes	No changes	No changes

a – Changes described are compared to the costs and loads that would have been calculated if EPA was not accounting for the CCR rule.

9.4.2 Industry Assumptions/Factors

The steam electric cost model includes several data tables containing values for industry assumptions and factors. These assumptions and factors are used in the cost equations for all plants incurring costs for a specific technology option. These factors include the coefficients for the technology option equations and other input constants applicable to all plants incurring the specific technology option costs. For example, for the fly ash cost methodology, EPA used a dry fly ash density of 45 pounds/cubic foot (lbs/ft^3), to estimate the size of the silo(s) required to store the ash. EPA used this density for all generating units for which the fly ash compliance costs are applicable. For more information on the specific technology cost module factors, see EPA's *Incremental Costs and Pollutant Removals for Final Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category* report [U.S. EPA, 2015a].

Although each technology cost module contains its own set of factor tables, there are two sets of industry factors referenced by all technology option modules. These coefficients and constants do not change based on the different elements of the technology cost modules. These industry factors include:

- **Cost Indices**. EPA adjusted all costs to 2010 dollars using the RS Means Historical Cost Index values for all technology cost modules [RSMeans, 2015].

- **Freight Cost Factors.** The factors used to estimate shipping costs are universal for all technology options. EPA estimated these values using data from FreightCenter.com and vendor contacts. [U.S. EPA, 2015a].

9.4.3 Technology Cost Modules

To estimate the plant-level technology option compliance costs, EPA developed eight different technology cost modules that use the various input data, industry assumptions and factors, and costing methodologies to generate plant-specific compliance cost outputs. Each technology cost module calculates specific cost components for each plant incurring compliance costs. The technology cost modules and a brief description of the cost components calculated are included in the following list.

- Biological Treatment – calculates capital and O&M costs for an anoxic/anaerobic biological treatment system.
- Chemical Precipitation – calculates capital and O&M costs for the chemical precipitation system.
- Evaporation – calculates capital and O&M costs for the evaporation system,
- Dry Fly Ash Handling – calculates capital, O&M, and recurring costs for the dry fly ash handling system.
- Dry Bottom Ash Handling – calculates capital, O&M, one-time, and recurring costs for the dry or closed-loop recycle bottom ash handling systems.
- Transportation – calculates O&M costs for transporting FGD solid waste, ash, and/or landfill leachate solid waste to an on- or off-site landfill.
- Disposal – calculates capital and O&M costs for disposing of FGD, ash, and/or landfill leachate solid waste in an on- or off-site landfill.
- Impoundment Operation – calculates O&M and recurring costs for operating and maintaining an on-site impoundment.

For each technology option shown in Table 9-1, the cost model sums the costs calculated from the technology cost modules that compose each option to calculate total capital, total O&M, and one-time and recurring costs.

9.4.4 Model Outputs

The cost model output is a plant-level summary of the incremental technology option costs. The output reflects each plant incurring a cost for an evaluated wastestream. EPA presents the incremental costs on two levels: at the cost-component level and at the total plant level. The total plant costs include total capital costs, total O&M costs, total 3-year recurring costs, total 5-year recurring costs, total 6-year recurring costs, total 10-year recurring costs, and total one-time costs incurred by the plant. The cost-component level shows a breakdown of the individual components for each of the technology costs. The cost-component level includes equipment costs, direct capital costs, indirect capital costs, and individual O&M costs (*e.g.* labor, materials, energy, effluent monitoring, and chemicals). See Sections 9.6.4, 9.7.3, 9.8, and 9.9 for the cost model outputs for each technology.

9.5 COSTS APPLICABLE TO ALL WASTESTREAMS

EPA developed several methodologies to calculate compliance costs applicable to more than one technology option. Using this approach, EPA could use the same methodology for each technology option without duplicating the calculations in the cost model. For example, the cost methodology for disposing of combustion residual solid waste in a landfill is the same for each type of waste; however, the input values and factors (*i.e.*, type, amount, and density of waste) vary depending on the wastestream (*e.g.*, FGD, fly ash, or bottom ash). The following sections describe the methodology used to estimate costs for compliance monitoring, transportation, disposal, and impoundment operations.

9.5.1 Compliance Monitoring Costs

Where a regulatory option would establish requirements for pollutants not regulated in the previously established ELGs, EPA calculated plant-level compliance monitoring costs for plants to sample and analyze their discharges to assess their compliance with the associated effluent limitations and standards. Compliance monitoring costs are annual O&M costs calculated by summing the components shown in the equation below.

Compliance Monitoring Costs = Sampling Labor Costs + Sampling Materials Costs + Sample Preservation Costs + Sample Shipping Costs + Sample Analysis Costs

Sampling labor costs are the costs associated with plant personnel collecting and analyzing wastewater samples. EPA calculated sample labor costs using a labor rate and the total number of labor hours required per year. EPA assumed samples would be collected and analyzed weekly for National Pollutant Discharge Elimination System (NPDES) compliance monitoring. EPA used data from the Steam Electric Survey and the U.S. Bureau of Labor Statistics to estimate the labor rate for the sampling team and environmental engineer required to collect and analyze the samples. EPA based the number of labor hours on the labor required during its field sampling program.

Sampling material and supply costs are the costs associated with the materials and supplies, such as personal protective equipment, sampling containers, and other supplies, required to collect and analyze samples. EPA calculated material and supply costs using the cost of the materials and supplies per sampling event and the number of sampling events per year. EPA based the sampling material costs on the costs it incurred for individual items during its field sampling program. EPA multiplied the item costs by the number of items that would be required over the course of a year and then summed the costs for all the individual items.

EPA estimated sample preservation costs for nitrate/nitrite samples. These samples require chemical preservation to ensure that pollutants present in the wastewater do not degrade prior to laboratory analysis. EPA based the sample preservation costs on the costs it incurred during its field sampling program. Sample preservation is not required for arsenic, selenium, or mercury.

EPA estimated the costs for shipping the samples to laboratories using the cost of a sample shipment and the total number of sample shipments per year. EPA assumed that samples would be sent to two different laboratories, one for analysis of low-level mercury and one for analysis of other metals. EPA assumed that one of these laboratories would be able to analyze the samples for total dissolved solids and nitrate-nitrite as N. This methodology would overestimate costs for those plants that are already monitoring for these pollutants.

EPA calculated sample analysis costs using the cost of analyzing each sample that would be collected per sampling event and the number of sampling events per year. EPA based the sample analysis costs on the costs it incurred during its field sampling program. See Section 5.2 of EPA's *Incremental Costs and Pollutant Removals for Final Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category* report for more details on the compliance monitoring cost methodology [U.S. EPA, 2015a].

9.5.2 Transportation Costs

Steam electric power plants can reuse, market/sell, or give away combustion residuals. Alternatively, plants can transport combustion residuals to a disposal site (*e.g.*, landfill). For the ELGs, EPA conservatively included costs for plants to transport all solid waste generated as a result of complying with the ELGs to a landfill because not all plants have the means to market/sell or give away the combustion residuals.

All combustion residuals can be transported to on-site or off-site landfills in an open dump truck. EPA included costs for plants with existing on-site landfills containing combustion residuals to dispose of any combustion residuals resulting from compliance with the ELGs in an on-site landfill (*e.g.*, wet ash handling system converted to dry ash handling system), by either expanding the existing landfill or building a new landfill to accommodate the additional waste. For plants that do not have existing on-site landfills (or have only on-site landfills that do not contain combustion residuals), EPA included costs for these plants to dispose of the additional combustion residuals in an off-site nonhazardous landfill. Costs for disposing of combustion residuals are described in Section 9.5.3.

EPA used data from the Steam Electric Survey to identify which plants have existing landfills containing combustion residuals. EPA estimated costs for on-site transportation of ash and FGD solids for all plants with at least one open landfill containing combustion residuals. EPA estimated off-site transportation costs for ash and FGD solids for all other plants (*i.e.*, those without an open landfill containing fuel combustion residuals).

EPA based plant-level costs for transporting combustion residuals on the total amount of waste generated at each plant as a result of compliance with the ELGs. For each wastestream, EPA calculated the amount of solid waste generated using methodologies presented, by technology option, in Sections 9.6, 9.7, and 9.8.

EPA estimated transportation costs for plants with an on-site landfill using the estimated amount of solid waste and an on-site specific unitized cost value, in dollar per ton. The dollar per ton of solid waste value for on-site landfills is based on information provided by ORCR for the CCR rule, developed using the Remedial Action Cost Engineering Requirements (RACER 2010) software version 10.4. EPA estimated transportation costs for plants with an off-site landfill using the estimated amount of solid waste and an off-site specific unitized cost value, in dollar per ton. The dollar per ton of solid waste value for off-site landfills was provided by ORCR based on the RACER 2010 model. For each plant and wastestream, EPA summed the total tonnage of combustion residuals generated as a result compliance with the ELG and multiplied it by the appropriate transportation cost to estimate a plant-specific transportation cost for each wastestream. See Section 5.3 of EPA's *Incremental Costs and Pollutant Removals for Final Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category* report for more details on the on- and off-site transportation cost methodologies [U.S. EPA, 2015a].

9.5.3 Disposal Costs

EPA conservatively determined costs for plants to dispose of all combustion residuals generated as a result of compliance with the ELGs in on-site or off-site landfills. For plants able to market/sell these residuals, EPA overestimated the disposal costs and has not accounted for any revenue associated with other marketing options. As , EPA used data from the Steam Electric Survey to identify which plants have existing on-site landfills containing combustion residuals. EPA estimated costs for on-site disposal of ash and FGD solids for all plants with at least one open landfill containing combustion residuals. The costs include those for the plant to expand the landfill to handle the additional combustion residuals that will need to be stored in the landfill to comply with the ELGs. EPA estimated off-site disposal costs (*e.g.*, tipping fees) for ash and FGD solids for all other plants (*i.e.*, those without an open landfill containing combustion residuals).

EPA based plant-level costs for disposal of combustion residuals on the total amount of waste generated at each plant as a result of complying with the ELGs. For each wastestream, EPA calculated the amount of solid waste generated using methodologies presented, by technology option, in Sections 9.6, 9.7, and 9.8.

For disposal in an on-site landfill, capital costs include the construction of the landfill, liner, additional groundwater monitoring, leachate collection system, and closures associated with expanding an existing landfill. EPA used a unitized cost value (in dollars per ton), that represents the capital cost components for an on-site landfill, and the estimated amount of solid waste produced from implementing the technology options. EPA used a similar unitized cost approach to estimate the O&M costs based on the estimated amount of additional solid waste produced and a unitized cost value (in dollar per ton), that represents the costs associated with operating the landfill.

EPA estimated off-site disposal costs using a unitized cost (in dollar per ton) and the estimated amount of additional solid waste transported off-site. The unitized cost value represents the fee off-site landfills generally charge prior to accepting waste, known as the tipping fee. EPA estimated the tipping fees using state-level tipping fees and data provided in the Steam Electric Survey. See Section 5.4 of EPA's *Incremental Costs and Pollutant Removals for Final Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category* report for more details on the on- and off-site disposal cost methodologies [U.S. EPA, 2015a].

9.5.4 Impoundment Operation Costs

Implementing the technology options will reduce, and in some cases eliminate, FGD wastewater, ash transport water, and combustion residuals managed in on-site impoundments. EPA therefore expects plants will experience cost savings associated with not operating these impoundments. To calculate the incremental compliance cost of the technology option, EPA estimated the annual O&M and recurring costs associated with managing these wastewaters and combustion residuals in on-site impoundments. For each technology option evaluated, EPA estimated the amount of wastewater or combustion residual no longer expected to be managed in on-site impoundments and the associated cost savings. EPA estimated O&M and 10-year recurring costs associated with impoundment operations using the equations provided below. See Section 5.5 of EPA's *Incremental Costs and Pollutant Removals for Final Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category* report for more details on the impoundment operation cost methodology [U.S. EPA, 2015a].

Total O&M Costs = (-1) × (Impoundment O&M Costs + Earthmoving O&M Costs) × (Capacity Factor)

Impoundment O&M costs are the costs associated with operating the impoundment, including the transportation system (*i.e.*, pipelines, vacuum source), the impoundment site, the treatment operations (*e.g.*, pH adjustment), and the water recycle system at the impoundment.[105] EPA calculated impoundment O&M costs using a unitized cost value ($7.35/ton), representing the impoundment O&M costs only, and the estimated difference in the amount of wet FGD solids, fly ash, and bottom ash entering an impoundment at baseline and after compliance.

Earthmoving O&M costs are the costs associated with operating earthmoving equipment (*e.g.*, front-end loader) required for sorting/stacking fuel combustion residual materials at the impoundment site. EPA calculated the earthmoving O&M costs using a unitized cost value ($2.49/ton), representing the O&M costs associated only with operating the earthmoving equipment, and the estimated difference in the amount of wet FGD solids, fly ash, and bottom ash entering an impoundment at baseline and after compliance.

Additionally, EPA applied a capacity factor to adjust both unitized cost values for impoundment and earthmoving O&M costs based on the size of plant (in MW). EPA applied this factor to account for the economies of scale, the concept that larger plants, which will generally operate larger impoundments, incur smaller costs per ton of wet combustion residual [U.S. EPA, 1985].

[105] EPA estimated costs associated with operating the transportation system (*i.e.*, pipelines, vacuum source) for the fly ash portion of the estimate. These costs were excluded from the bottom ash portion of the estimate due to the two technology options selected by EPA for bottom ash (MDS and remote MDS). The compliance costs associated with the MDS already accounts for these savings. Alternatively, the remote MDS still requires using the existing wet-sluicing system to transport the bottom ash to the remote MDS destination.

Total 10-Year Recurring Costs = (-1) × (Cost of Earthmoving Vehicle)

EPA calculated 10-year recurring costs associated with operating the earthmoving equipment (*i.e.*, front-end loader). EPA calculated the total 10-year recurring costs by determining the cost and average expected life of a front-end loader. EPA determined that the expected life of a front-end loader is 10 years and that each plant will operate one front-end loader per each type of combustion residual waste (*e.g.*, FGD solids, fly ash, or bottom ash) identified as entering an impoundment at baseline.

9.6 FGD WASTEWATER

EPA estimated capital, O&M, 6-, and 10-year recurring costs associated with installing three technology options for FGD wastewater:

- Chemical Precipitation.
- Chemical Precipitation followed by Biological Treatment.
- Chemical Precipitation followed by Evaporation.

EPA estimated the chemical precipitation, biological treatment, and evaporation system costs separately, and then summed the costs generated by the appropriate technology cost modules to achieve the total technology option costs (*i.e.*, the chemical precipitation costs were added to the biological treatment and evaporation costs to calculate the total costs for the technology option).

9.6.1 Chemical Precipitation

Section 7.1.2 describes the chemical precipitation system that forms the basis for this technology option. Additionally, Section 9.2.1 summarizes the technology basis for the chemical precipitation system. EPA estimated the costs to install and operate a chemical precipitation technology to treat FGD wastewater, specifically developed to remove mercury and arsenic (and other heavy metals). See Section 6.1 of the *Incremental Costs and Pollutant Removals for Final Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* for more details on the FGD chemical precipitation cost methodology [U.S. EPA, 2015a].

Based on site visits, EPA determined that untreated FGD wastewater can contain elevated mercury concentrations based on a variety of different plant operating characteristics. To ensure that the mercury concentrations in the effluent discharged from the chemical precipitation system meet the ELGs, EPA included costs for a mercury analyzer and extra equipment to analyze mercury in the FGD wastewater discharge and, if necessary (*i.e.*, when effluent concentrations do not meet the ELGs), recycle the chemical precipitation discharge for further treatment. Using this equipment will allow plants to test the mercury in the effluent daily to ensure compliance with the ELGs. If the wastewater is not in compliance, the plant can recycle the treated water back to the equalization tank and adjust the system (*i.e.*, add additional chemicals) to further treat the wastewater to meet the ELGs. See Section 7 for additional details.

As noted in Section 9.4.1, EPA evaluated plant responses to the Steam Electric Survey to determine whether chemical precipitation technologies are currently in place to treat FGD wastewater. As appropriate, plants operating these technologies were given credit for having treatment in place. EPA gave plants credit only for the associated cost components that are already in place at the plant. For example, for Regulatory Option D, if a plant operates a chemical precipitation system to treat FGD wastewater that includes all the steps included as the basis for the technology option other than sulfide precipitation, then EPA included capital costs for the plant to install a reaction tank and sulfide chemical feed system and O&M costs for the amount of sulfide added to the system on a yearly basis, plus the full capital and O&M costs for the biological treatment system. A plant would not incur compliance costs for pieces of equipment that are part of the technology basis and already installed and operating at the plant.

EPA estimated capital, O&M, and 6-year recurring costs for a chemical precipitation system using the equations provided below.

Total Capital Costs = Purchased Equipment Costs + Direct Capital Costs + Indirect Capital Costs + Sludge Disposal Costs

Purchased equipment costs are the costs to purchase the pieces of equipment required to construct a chemical precipitation system, in addition to ancillary equipment and freight costs. EPA included the following pieces of equipment in the calculation of the chemical precipitation system purchased equipment costs:

- Pumps.
- Tanks (*e.g.*, equalization tanks, reaction tanks, holding tanks).
- Chemical feed systems.
- Mixers.
- Clarifiers.
- Filter presses.
- Sand filters.
- Mercury analyzer.

For each piece of equipment, EPA obtained cost information from vendors for various sizes of the equipment (*e.g.*, flow, volume). EPA then related all of these to an associated flow rate using information based on the technology design basis (*e.g.*, tank volume related to flow by design residence time). EPA then used the cost and flow information to generate an equation that could estimate the costs for any FGD wastewater flow rate.

Direct capital costs account for all costs incurred as a direct result of installing the chemical precipitation system. The direct capital costs include purchased equipment installation,[106] building, land, and site preparation. Indirect capital costs account for all non-direct costs incurred as a result of installing the treatment system. The indirect capital costs (*e.g.*,

[106] Purchased equipment installation costs are the costs associated with installing those pieces of purchased equipment, including piping, instrumentation, calibration, and structural supports.

engineering, construction, and other contractor fee costs) are those associated with preparing a specific site for installing the chemical precipitation equipment and the costs required for supervising and inspecting the installation. EPA estimated the direct capital costs by developing a cost factor from data provided in response to the Steam Electric Survey. EPA used the median ratio of total direct capital costs to total reported purchased equipment costs based on the plants in the analysis. Therefore, once EPA calculated the total purchased equipment costs for chemical precipitation, EPA then multiplied the cost by median ratio to estimate the direct capital cost. EPA estimated indirect capital costs as a percentage of the total direct capital costs (purchased equipment costs plus direct capital costs) based on information obtained from a publically available costing manual, *Plant Design and Economics for Chemical Engineers* (Peters and Timmerhaus, 1991). See Section 6.2.6.10 of the *Incremental Costs and Pollutant Removals for Final Effluent Limitations Guidelines and Standards for the Steam Electric Generating Point Source Category* report for more details on the methodology for estimating the indirect capital costs [U.S. EPA, 2015a].

To calculate the sludge disposal costs, associated with on-site landfill disposal described in Section 9.5.3, EPA needed to estimate the annual generation of sludge associated with the chemical precipitation treatment system. EPA used data from the Steam Electric Survey to compare the quantity of FGD wastewater treatment sludge generated to the FGD wastewater treatment system flow rate. EPA calculated a ratio of these values for each plant and used the median as a flow-normalized dewatered sludge generation rate in tons per gallon. Then, based on the plant-specific FGD wastewater flow rate, EPA estimated the quantity of sludge generated by the system.

Total O&M Costs = Operating Labor Costs + Maintenance Labor Costs + Maintenance Materials Costs + Chemical Purchase Costs + Energy Costs + Sludge Transportation Costs + Sludge Disposal Costs + Compliance Monitoring Costs + Impoundment Operation Costs

Operating labor, maintenance labor, and maintenance materials costs are the costs associated with the manual labor and materials required to operate and maintain the chemical precipitation system 24 hours per day, 365 days per year. To estimate these labor costs, EPA used data from the Steam Electric Survey to compare the labor costs to the flow rate of the system. From the costs reported in response to the Steam Electric Survey and the associated FGD wastewater treatment flow rate, EPA developed equations to estimate the cost based on the flow rate. EPA then used these equations and each plant's FGD wastewater flow rate to determine the operating labor and maintenance labor costs. EPA performed a similar analysis to estimate the maintenance materials costs by using data from the Steam Electric Survey to develop an equation relating FGD wastewater treatment flow rate to the total yearly maintenance material costs.

Chemical purchase costs are the costs to purchase the chemicals required to operate the chemical precipitation system. EPA estimated chemical purchase costs using a chemical dosage rate (expressed in grams of chemical per liter of wastewater flow), the plant FGD wastewater flow rate, and chemical costs (expressed in dollars per ton). EPA determined the appropriate dosage rates based on the average chemical dosage rates used by the BAT plants included in

EPA's sampling program. EPA obtained chemical costs directly from chemical suppliers in dollars per ton.

Energy costs are the costs associated with the power requirement to run the chemical precipitation system. EPA obtained the power requirements for each piece of equipment used in the system from equipment vendors and used these power requirements to develop energy cost equations and estimate total energy consumption in kilowatt hour per year (kWh/yr). EPA used the national 2010 energy cost of 4.05 cents per kWh to calculate the energy cost [U.S. DOE, 2011].

EPA estimated the O&M costs associated with compliance monitoring, transportation, disposal, and impoundment operations savings according to the methodologies described in Section 9.5. EPA used the same estimated tonnage described for the capital cost equation above to estimate sludge transportation, disposal, and impoundment operation costs.

Total Recurring 6-Year Costs = Cost of Mercury Analyzer

EPA calculated 6-year recurring costs associated with operating a mercury analyzer, which is included in the system to allow plants to monitor the effluent quality daily to ensure the treatment system is effectively treating mercury to meet the final effluent limitations. EPA estimated the total 6-year recurring costs by determining the cost and average expected life of a mercury analyzer, based on vendor information. EPA assumed that the expected life of a mercury analyzer is 6 years and that each plant will operate one analyzer for FGD wastewater.

9.6.2 Biological Treatment

Section 7.1.3.2 describes the anoxic/anaerobic biological treatment system that forms the basis for this technology option. For Regulatory Options B, C, D, and E, EPA estimated compliance costs to install and operate the anoxic/anaerobic system to treat FGD wastewater in addition to the BAT chemical precipitation system. The anoxic/anaerobic system is specifically designed and operated to target removals of selenium and nitrate. See Section 6.2 of the *Incremental Costs and Pollutant Removals for Final Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* for more details on the FGD biological treatment cost methodology [U.S. EPA, 2015a].

The system uses up-flow, fixed-film granular activated carbon (GAC) bed bioreactors, inoculated with a proprietary, site-specific mixture of bacterial cultures, through which the FGD wastewater passes.

EPA developed pretreated FGD wastewater characteristics to use as the basis for cost development for the biological treatment system.[107] EPA developed these FGD wastewater

[107] The pretreated FGD wastewater characteristics developed for this analysis are similar to the chemical precipitation effluent characteristics identified in Section 10; however, they are slightly different because EPA had less data at the time this analysis was completed. The wastewater characteristics are included in *Incremental Costs and Pollutant Removals for Final Effluent Limitations Guidelines and Standards for the Steam Electric Generating Point Source Category* report [U.S. EPA, 2015a].

characteristics from industry site visits, its sampling program, and the Clean Water Act (CWA) 308 monitoring program. A treatment vendor developed the specific anoxic/anaerobic biological treatment system design and system-level costs based on its evaluation of these pretreated FGD wastewater characteristics. The anoxic/anaerobic biological system design consists of a series of two bioreactors operating in parallel trains. The number of trains and the size of the bioreactors depend on a plant's FGD wastewater flow rate. For flow rates greater than 25 gpm, the vendor provided costs for customized field-erected biological treatment systems. For flow rates less than 25 gpm, the vendor provided costs for a low-flow, prefabricated modular reactor, which is more cost-effective for this flow range.

Based on site visits, EPA's sampling program, and the CWA 308 monitoring program, FGD wastewater temperatures can exceed the maximum operating temperature for the biological treatment system, especially during the warmer seasons, and the wastewater may require cooling prior to entering biological treatment. Therefore, the design basis includes a heat exchanger for certain southern plants that EPA determined required cooling of FGD wastewater for biological treatment, based on set latitudinal and longitudinal coordinates where the average July temperature is 90°F or greater. The design basis also includes a building for northern plants, located in areas where the mean daily minimum temperature is below 32°F, to house biological treatment equipment to prevent freezing.

As described in Section 7.1.3, EPA included an ORP monitor as part its design basis of the biological treatment system. This monitor is installed in the FGD purge line (or at the chemical precipitation equalization tank) to monitor ORP, which may affect biological treatment performance, in the biological treatment influent. The monitor serves to notify operators to alter FGD operations to control the ORP, which is necessary to prevent corrosion of the FGD equipment and prevent mercury re-emission in stack emissions. Through contact with vendors and other industry representatives, EPA has learned that sodium bisulfite, a reducing agent, has been used in current FGD treatment systems to help control free oxidants that may be present during periods of elevated ORP.[108] The design basis in EPA's cost estimate includes a sodium bisulfite chemical feed system to counteract elevated ORP. See Section 7 for more details regarding elevated ORP levels in FGD scrubbers/wastewater and its effect on biological treatment systems.

Based on feedback from the biological treatment system vendor, FGD wastewater with nitrate-nitrite as N concentrations exceeding 100 milligrams per liter (mg/L) should be pretreated to reduce concentrations prior to the biological treatment stage. EPA used sampling data and responses to the Steam Electric Survey to identify plants with nitrate-nitrite as N concentrations at or above 100 ppm. For these plants, EPA included an additional denitrification system in its cost estimate to target removal of nitrate-nitrite in the FGD wastewater. EPA's design basis includes a tank and biofilm reactor installed downstream of the chemical precipitation system, but upstream of the biological treatment system for only those plants demonstrating elevated nitrate/nitrite concentrations.

[108] Using ferrous chloride (in place of ferric chloride) within the chemical precipitation treatment system can also control free oxidants.

As noted in Section 9.4.1, EPA evaluated responses to the Steam Electric Survey to determine whether a biological treatment system for selenium removal is currently in place to treat FGD wastewater. As appropriate, plants operating this technology were given credit for having treatment in place, to ensure that incremental costs associated with compliance with the technology options are accurately assessed. EPA gave plants credit only for the associated cost components that are already in place at the plant.

EPA estimated capital and O&M costs for the anoxic/anaerobic system using the equations provided below.

Total Capital Costs = Purchased Equipment Costs + Direct Capital Cost + Indirect Capital Cost + Sludge Disposal Costs

Purchased equipment costs are the costs to purchase the pieces of equipment required to construct the anoxic/anaerobic biological system. EPA calculated purchased equipment costs by summing the following costs:

- Anoxic/anaerobic biological system.
- Heat exchanger (for applicable plants).
- Backwash recycle pump.
- ORP monitor.
- Sodium bisulfite chemical addition system.
- Denitrification system (for applicable plants).

The vendor provided EPA with cost equations based on FGD wastewater flow rate and backwash flow rate for the anoxic/anaerobic system and backwash recycle pump, respectively. The vendor provided costs for the following cost components:

- Two-stage bioreactor system (*i.e.*, two reactors in series per train) with a 10-hour residence time for the system, operating 24 hours per day and 365 days per year. System-level costs include the following purchased equipment and associated ancillary equipment:
  - All process pumps, valves, and instruments.
  - Process and instrument compressed air system, valves, and lines.
  - Nutrient system, storage tank, and pumping.
  - Process piping and supports.
  - Concrete bioreactor tank walls and floor with epoxy-coated rebar and epoxy flake-glass coating.
  - Concrete backwash supply and backwash wastewater tank walls and floor with epoxy-coated rebar and epoxy flake-glass coating.
  - Concrete process and utility sump with pumps.
  - Support steel, access stairs, walkways, grating, and handrails.

- Process equipment building with heating, ventilating, and air conditioning (HVAC) (concrete floor, block structure with steel roof).
- Engineering, commissioning, and project management labor (the project structure is executed by a consortium between the vendor and contractor with a balance of plant engineering as a sub-contractor).
- Construction equipment, materials, and labor.

EPA used information obtained from vendors to develop cost equations for the heat exchanger, as well as the cooling water pump needed for some systems. Based on the chlorides level in the FGD wastewater and vendor recommendations, EPA developed heat exchanger costs for a carbon steel frame heat exchanger consisting of titanium plates. EPA estimated the size, and cost, of the cooling water pumps based on the flow for the FGD wastewater treatment system, accounting for the estimated heat transfer required to reduce the wastewater temperature to 95°F prior to entering the bioreactors.

EPA also used information from vendors to develop cost equations for the ORP monitor and sodium bisulfite chemical addition system. EPA used pilot test data provided by the industry to estimate the concentration and dosage of sodium bisulfite needed to treat the FGD wastewater based on plant-specific FGD wastewater flow rates.

EPA used cost information from a vendor to develop cost equations for the denitrification system. The vendor provided EPA with cost estimates for three different FGD wastewater flow rates for the following cost components:

- One moving bed biofilm reactor (MBBR) (One reactor at100%).
- AnoxKaldnes™ media (specialized plastic biocarriers).
- Reactor mixer.
- Sieves.
- Two micro C feed pumps (Two pumps at 100%).
- One drumfilter (for 100 gpm) or discfilter (for 500 and 1,000 gpm) (One filter at 100%).
- All necessary probes and sensors.
- One phosphoric acid metering skid pump.
- One polymer feed pump.
- Start-up and training.
- Detailed engineering.
- Equipment shipping, unloading, and installation.
- Civil, mechanical, electrical, and instrumentation and controls.
- Access structure (*e.g.*, ladders, platforms).
- Performance testing.

EPA used the cost information to create cost curves used to estimate plant-level costs for specific flow rates.

Direct capital costs account for all costs incurred installing and erecting the biological treatment system. The direct capital costs include purchased equipment installation, building, land, and site preparation. Installation equipment costs are the costs associated with installing the purchased equipment, including any additional piping or instrumentation for the system. EPA estimated installation capital costs for the anoxic/anaerobic biological system for each plant using two different installation cost factors. The first factor was provided by the vendor and is specific to installing the anoxic/anaerobic biological system. The second factor was determined based on responses to the Steam Electric Survey and applies to installing the heat exchanger, system pumps, ORP monitor, and sodium bisulfite chemical feed system. This second factor is the same installation equipment cost factor used for the FGD chemical precipitation system. EPA did not estimate additional direct capital costs for the denitrification system because vendor estimates already include costs for installation, instrumentation and controls, and other installation activities.

EPA estimated costs for plants located in cold climates to erect a building to house the biological treatment system equipment to prevent freezing. EPA calculated a ratio of the building cost to the FGD wastewater treatment flow rate for each plant that reported cost and flow rate data in the Steam Electric Survey. EPA used the average ratio to estimate building costs for only those plants located in regions with below freezing mean daily minimum temperatures, based on data from the National Climate Data Center.

Indirect capital costs account for all non-direct costs incurred as a result of installing and erecting the treatment system. The indirect capital costs (*e.g.*, engineering, construction, other contractor fee costs) are those associated with preparing a specific site for installing the biological treatment system and the costs required for supervising and inspecting the installation. EPA estimated indirect capital costs as a percentage of the total direct costs (purchased equipment costs plus direct capital costs) based on information obtained from a publically available costing manual, *Plant Design and Economics for Chemical Engineers* (Peters and Timmerhaus, 1991). See Section 6.2.5.7 of the *Incremental Costs and Pollutant Removals for Final Effluent Limitations Guidelines and Standards for the Steam Electric Generating Point Source Category* report for more details on methodology for estimating the indirect capital costs [U.S. EPA, 2015a].

The sludge generated by the biological treatment system is associated with the backwash from the system. The backwash water is recycled to the equalization tank prior to the FGD wastewater chemical precipitation system and is ultimately removed with the chemical precipitation sludge. The vendor provided an equation to calculate the estimated annual amount of dry solids generated during the backwash based on plant-specific FGD wastewater flow. EPA used the sludge generation rate to estimate the disposal costs, described in Section 9.5.3.

Total O&M Costs = Operating Labor Costs + Maintenance Labor Costs + Maintenance Materials Costs + Chemical Purchase Costs + Energy Costs + Compliance Monitoring Costs + Sludge Transportation Costs + Sludge Disposal Costs + Impoundment Operation Costs

Operating labor, maintenance labor, and maintenance material costs are the costs associated with the manual labor and materials required to operate and maintain the anoxic/anaerobic system 24 hours per day, 365 days per year. EPA estimated these labor costs using vendor data and industry responses to the Steam Electric Survey to estimate the number of full time equivalent workers required to operate the system. EPA used number of workers and the median operation and maintenance labor rates from responses to the Steam Electric Survey to calculate the labor costs. To calculate the maintenance materials costs, EPA used Steam Electric Survey data to calculate a ratio of the reported maintenance materials costs to the sum of the energy, chemical, and O&M labor costs for plants that operate FGD chemical precipitation and/or biological treatment systems. EPA then used the calculated value and multiplied it by the sum of the energy, chemical, and O&M labor costs to estimate the maintenance material costs for each plant.

Chemical purchase costs are the costs to purchase the chemicals required to operate the anoxic/anaerobic biological system and denitrification system (if applicable). EPA estimated the chemical purchase costs for the anoxic/anaerobic biological system using nutrient dosages provided by the vendor, based on an assumed nitrate/nitrite (as nitrogen) concentration in the FGD wastewater, a nutrient cost provided by the vendor, and the plant-specific FGD wastewater flow rate. EPA estimated chemical purchase costs for the denitrification system using unit cost and dosage information provided by the vendor, based on FGD wastewater flow rate.

Energy costs are the costs associated with the power requirement to run the anoxic/anaerobic biological system. Vendors provided equations to calculate power requirements per gallon of FGD wastewater for the anoxic/anaerobic biological system and the denitrification system. EPA calculated the annual anoxic/anaerobic biological system energy consumption (kWh/yr) by multiplying the anoxic/anaerobic biological system energy requirement by the plant-specific FGD wastewater flow and backwash flow. EPA used a similar process to calculate the denitrification system energy requirement using the denitrification system energy consumption (kWh/yr) multiplied by the plant-specific FGD wastewater flow and backwash flow. For the pumps, EPA developed energy cost equations based on the power requirements provided by equipment vendors (kWh/yr). EPA used the national 2010 energy cost of 4.05 cents per kWh to calculate the energy cost [U.S. DOE, 2011].

EPA estimated the O&M costs associated with compliance monitoring, transportation, disposal, and impoundment operations savings according to the methodologies described in Section 9.5. EPA used the same estimated tonnage described for the capital cost equation above to estimate sludge transportation, disposal, and impoundment operation costs.

9.6.3 Evaporation

Section 7.1.4 describes the evaporation system that forms the basis for this technology option. The purpose of the evaporation system is to evaporate and condense the water from the FGD wastewater to produce a clean distillate stream and a concentrated brine solution. The concentrated brine solution is then further treated to generate a solid by-product. As described in Section 9.2.1, EPA estimated compliance costs for plants to treat FGD wastewater using chemical precipitation followed by evaporation but determined that the total industry cost would be too high to warrant further evaluation of this technology as a BAT option for existing sources

[ERG, 2015f]. The methodology used to estimate compliance costs associated with chemical precipitation followed by evaporation is described in detail in Section 6.3 of the *Incremental Costs and Pollutant Removals for Final Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* [U.S. EPA, 2015a].

9.6.4 Estimated Industry-Level Costs for FGD Wastewater by Treatment Option

Table 9-5 presents the estimated capital and O&M costs on an industry level for each FGD wastewater treatment technology discussed in the sections above, including compliance monitoring, transport, disposal, and impoundment costs. The table also includes the number of plants incurring costs for each technology option. The costs presented in the table represent the compliance costs for those generating units facing more stringent requirements under the final rule than exist under the previously established regulations; therefore, oil-fired generating units and generating units with a capacity of 50 MW or less are not included because they do not need to meet any more stringent requirements than already existed under BPT regulations. See EPA's *Incremental Costs and Pollutant Removals for Final Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category* report for the costs for all generating units [U.S. EPA, 2015a]. Table 9-6 adjusts the results shown in Table 9-5, accounting for the expected closures related to the implementation of the CPP.

Table 9-5. Estimated Industry-Level Costs for FGD Wastewater Based on Oil-Fired Units and Units 50 MW or Less Not Installing Technology Basis

Technology Option	Number of Plants	Total Capital Cost ($)	Total O&M Cost ($/year)	6-Year Recurring Cost ($/6-year)	10-Year Recurring Cost ($/10-year) [a]
Chemical Precipitation	87	$888,000,000	$78,100,000	$7,420,000	($20,500,000)
Chemical Precipitation followed by Biological Treatment	87	$1,790,000,000	$123,000,000	$7,420,000	($20,500,000)

Note: Costs are rounded to three significant figures.

Note: All costs are indexed to 2010 dollars using RSMeans Historical Cost Indices [RSMeans, 2015].

a – The values in this column are negative, and presented in parenthesis, because they represent cost savings.

Table 9-6. Estimated Industry-Level Costs for FGD Wastewater Based on Oil-Fired Units and Units 50 MW or Less Not Installing Technology Basis, Accounting for CPP

Technology Option	Number of Plants	Total Capital Cost ($)	Total O&M Cost ($/year)	6-Year Recurring Cost ($/6-year)	10-Year Recurring Cost ($/10-year) [a]
Chemical Precipitation	69	$775,000,000	$67,500,000	$5,890,000	($16,100,000)
Chemical Precipitation followed by Biological Treatment	69	$1,510,000,000	$103,000,000	$5,890,000	($16,100,000)

Note: Costs are rounded to three significant figures.

Note: All costs are indexed to 2010 dollars using RSMeans Historical Cost Indices [RSMeans, 2015].

a – The values in this column are negative, and presented in parenthesis, because they represent cost savings.

9.7 Ash Transport Water

As discussed in Section 4.2.1, combusting coal and oil in steam electric boilers produces a residue of noncombustible fuel constituents, referred to as ash. The ash that is light enough to be carried out of the boiler is referred to as fly ash and the heavier ash that falls to the bottom of the boiler is referred to as bottom ash.

Based on Steam Electric Survey responses, plants usually collect and handle fly ash and bottom ash separately. Fly ash is either handled dry and pneumatically transferred to silos for temporary storage or sluiced with water to an impoundment. Bottom ash is either collected in a water-filled hopper positioned below the hopper and sluiced with water to an impoundment, collected under the boiler using a mechanical drag system and stored in an outdoor pile for temporary storage, or pneumatically transferred to silos for temporary storage. Based on information from vendors and industry site visits, bottom ash can also be collected under the boiler using a completely dry mechanical conveyor and conveyed to silos for temporary storage.

Because of the development of ash handling systems that require little to no water and the ability to market dry fly and/or bottom ash, plants have been converting handling operations on existing steam electric generating units from wet-sluicing operations to systems that do not transport the ash with water. The following sections describe the technology bases used to estimate the compliance costs to convert from wet to dry fly ash handling and wet to dry or closed-loop recycle bottom ash handling.

9.7.1 <u>Fly Ash Transport Water</u>

EPA estimated capital, O&M, and 10-year recurring costs associated with converting wet fly ash handling systems to dry vacuum fly ash handling systems for steam electric generating units producing and discharging fly ash transport water. Section 7.2.4 provides more details on the dry vacuum fly ash handling system.

EPA's approach for estimating costs associated with converting to dry vacuum systems is described in more detail below. See Section 7 of the *Incremental Costs and Pollutant Removals* *for Final Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* for more details on the fly ash cost methodology [U.S. EPA, 2015a].

Dry Vacuum Conversion

Based on data from the Steam Electric Survey and site visits, EPA determined that a single steam electric generating unit can be equipped with both wet and dry fly ash handling capabilities. Therefore, not all steam electric generating units are expected to incur complete conversion costs depending on the equipment and its capacity already operating at the plant. For example, the vacuum lines for a generating unit may have the capacity to handle all of the dry fly ash generated, but the silo may not be large enough to store all of the dry fly ash. In such cases, EPA estimated compliance costs associated with the additional intermediate storage (silo capacity) required. As appropriate, plants with wet and dry fly ash handling systems were given credit for having this equipment at the plant. To estimate compliance costs for a fly ash handling conversion to a dry vacuum system, EPA developed a costing approach for three separate portions of the system:

- **Conveyance**. The portion of the fly ash handling system from the bottom of the collection hopper to the intermediate storage destination that includes the mechanical exhauster, piping, valves, and filter-separators necessary to pull and convey ash from the bottom of the hopper. EPA calculated conveyance costs at the steam electric generating unit level.
- **Intermediate Storage**. The destination to which the dry fly ash is conveyed from the bottom of the hopper. The intermediate storage includes the structure itself (*e.g.*, the silo), including the vacuum equipment necessary to receive the fly ash from the conveyance lines and the unloading equipment necessary for moisture conditioning prior to transportation and disposal.[109] EPA calculated intermediate storage costs at the plant level.
- **Transportation/Disposal**. The trucking equipment and operation to move the dry fly ash to its final destination (*e.g.*, on-site or off-site landfill). EPA calculated transport/disposal costs at the plant level.

EPA also identified a specific subset of plants operating both dry and wet fly ash handling systems in the Steam Electric Survey; these plants indicated that redundant equipment would be required to discontinue the use of the wet fly ash handling system. EPA estimated the capital costs associated with the redundant equipment based on the type of dry fly ash handling system already installed at the plant (*e.g.*, vacuum, pressure, or combined vacuum/pressure).

EPA estimated capital, O&M, and 10-year recurring costs for converting to dry fly ash handling with a dry vacuum system using the equations provided below.[110] EPA calculated the

[109] Plants may have a silo but, they may need to install the equipment for moisture-conditioning fly ash prior to unloading. Therefore, the intermediate storage costs are based on two cost indicators, one of the silo and one for the pugmill.

[110] For plants requiring redundant or back-up equipment, EPA estimated only capital compliance costs; EPA did not estimate O&M and recurring costs for these plants because the equipment installed is for back-up and is only

capital, O&M, and 10-year recurring costs by summing the estimated costs for the conveyance, intermediate storage, and transport/disposal portions of the system.

Total Capital Costs = Purchased Equipment Costs + Direct Capital Costs + Indirect Capital Costs + Fly Ash Disposal Costs

Purchased equipment costs are the costs to purchase all equipment to retrofit all generating units that collected fly ash with a wet-sluicing system, with a dry vacuum conveyance system. EPA calculated purchased equipment costs by summing the costs of dry vacuum conveyance system(s), the concrete or steel silo(s), silo aeration equipment, and pugmill(s). EPA calculated equipment costs for the conveyance system on a generating unit level, and calculated silo and pugmill equipment costs at a plant level. EPA estimated conveyance, silo, and pugmill equipment costs using a relationship between capital costs and wet fly ash generation rate obtained from industry vendors.

Direct capital costs incurred to install the dry vacuum fly ash handling system include purchased equipment installation and site preparation. Indirect capital costs (*e.g.*, engineering, construction, and other contractor fee costs) incurred to install the dry vacuum fly ash handling system are the costs associated with preparing a specific site for the installation of the dry vacuum equipment and the costs required for supervising and inspecting the installation. EPA estimated direct capital costs associated with conveyance and intermediate storage for each plant using a direct capital cost factor determined from Steam Electric Survey, vendor, and other industry-submitted data. To estimate these costs, EPA applied the calculated factor to the purchased equipment cost. EPA estimated indirect capital costs as a percentage of the total direct capital costs (purchased equipment costs plus direct capital costs) based on information obtained from a publically available costing manual, *Plant Design and Economics for Chemical Engineers* [Peters and Timmerhaus, 1991]. See Section 7.1.5 of the *Incremental Costs and Pollutant Removals for Final Effluent Limitations Guidelines and Standards for the Steam Electric Generating Point Source Category* report for more details on methodology for estimating the indirect capital costs [U.S. EPA, 2015a].

EPA calculated the amount of moisture-conditioned fly ash generated from the handling conversion using the wet fly ash generation rate at the plant-level and an average moisture content of fly ash from the Steam Electric Survey data, supplemented with vendor data. EPA used the moisture-conditioned fly ash tonnage to estimate the disposal capital costs, described in Section 9.5.3.

operated when the back-up wet-sluicing system would have operated. EPA determined that the O&M and recurring costs associated with the wet-sluicing system are comparable to the dry system. Therefore, the operation of the redundant or back-up equipment results in no incremental O&M costs [U.S. EPA, 2015a].

Total O&M Costs = Operating Labor Costs + Maintenance Labor Costs + Maintenance Materials Costs + Energy Costs + Fly Ash Transport Costs + Fly Ash Disposal Costs + Impoundment Operation Costs

O&M labor costs are the costs associated with operating and maintaining the conveyance, intermediate storage, and transport/disposal portions of the dry vacuum system. To calculate the labor rate for fly ash conversion costs, EPA used the Steam Electric Survey data, supplemented with U.S. Bureau of Labor Statistics data [U.S. Bureau of Labor Statistics, 2010]. EPA calculated conveyance operating labor costs using the labor rate, the estimated number of required operator hours per day, and the total number of days the generating units operated. EPA calculated intermediate storage operating labor costs using the labor rate and the estimated number of operator hours per year. EPA calculated the maintenance labor costs using the labor rate and the estimated maintenance hours per year. Using data provided in the Steam Electric Survey, EPA estimated the number of required operator hours per day and maintenance hours per year. Additionally, EPA used the number of generating unit operating days in 2009 reported in the Steam Electric Survey.

In addition to the intermediate storage system operating labor costs, EPA also estimated O&M costs for operating dust suppression water trucks around the fly ash unloading area, including operating labor and fuel costs, if appropriate.[111] EPA estimated the water truck operating labor cost using a water truck labor rate, number of required operator hours per day, the number of operating days per year, and the number of silos. To determine the water truck labor rate, EPA selected the national average loaded labor rate for industrial truck/tractor operators as reported by the U.S. Bureau of Labor Statistics [U.S. Bureau of Labor Statistics, 2010]. EPA estimated the number of required operator hours per day and the number of operating days using data from the Steam Electric Survey. EPA calculated the number of silos as part of the fly ash capital cost methodology based on fly ash tonnage. To estimate the fuel costs associated with the water trucks, EPA multiplied the number of hours each water truck operates by the number of water trucks, the distance the water truck travels every hour, and the gas mileage and fuel cost. The number of water trucks required at a plant was determined using data from the *Regulatory Impact Analysis (RIA) For EPA's 2015 Coal Combustion Residuals (CCR) Final Rule* [ORCR, 2014], based on the dry fly ash tonnage produced at the plant after the ash handling conversion. Vendor contacts provided the water truck's fuel consumption. EPA assumed the same trip distance and fuel cost from the disposal technology cost methodology.

Maintenance materials costs are the costs associated with replacing equipment due to routine wear and tear. EPA used data from the Steam Electric Survey to determine conveyance and intermediate storage maintenance materials factors based on a comparison of maintenance material costs to the total O&M costs for conveyance and intermediate storage system elements,

[111] For plants that already have some portion of dry fly ash handling, EPA included only additional costs for water trucks if the additional tonnage that would now be handled dry would likely lead the plant to purchase and operate additional water trucks. See Section 7.1.9 of the *Incremental Costs and Pollutant Removals for Final Effluent Limitations Guidelines and Standards for the Steam Electric Generating Point Source Category* for additional details on the water truck methodology [U.S. EPA, 2015a].

respectively. EPA calculated a median maintenance materials factor for each system element (*i.e.*, conveyance, intermediate storage) and applied it to the calculated O&M costs.

Energy costs are the costs associated with the power requirement to run the dry vacuum system and intermediate storage. EPA obtained the power requirements for each piece of equipment (pumps and pugmills) used in the system from the vendors and used these power requirements to develop energy cost equations for the system pumps and pugmill(s) and estimate total energy consumption (kWh/yr). EPA used the national 2010 energy cost of 4.05 cents per kWh to calculate the energy cost [U.S. DOE, 2011].

EPA estimated the O&M costs associated with transportation, disposal, and impoundment operations savings according to the methodologies described in Section 9.5. EPA used the same estimated tonnage described for the capital cost equation to estimate fly ash transportation, disposal, and impoundment operation costs.

Total 10-Year Recurring Costs = Cost of Water Truck

EPA calculated 10-year recurring costs associated with intermediate storage water trucks by determining the cost, expected life, and number of water trucks required (from ORCR regulatory impact analysis information). EPA determined that the expected life of a water truck is 10 years.

9.7.2 Bottom Ash Transport Water

EPA estimated capital, O&M, 3-year recurring, 5-year recurring, and 10-year recurring costs associated with converting bottom ash handling systems from wet sluicing to an MDS or remote MDS for generating units producing and discharging bottom ash transport water. EPA selected two systems, the MDS and the remote MDS, as the basis for the dry and closed-loop recycle systems, respectively, based on system operation data from vendors and operation data from the Steam Electric Survey data. The compliance costs estimated by EPA include the conveyance system conversion, the additional required bottom ash storage, the transport and disposal of the bottom ash, and impoundment costs associated with the change in bottom ash handling. See Section 8 of the *Incremental Costs and Pollutant Removals for Final Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* for more details on the bottom ash cost methodology [U.S. EPA, 2015a].

EPA estimated costs for both MDS and remote MDS systems. The cost estimates reflect fully erected and commissioned systems, including equipment, controls, foundations, and field labor. For more detail on the MDS and remote MDS equipment, see Sections 7.3.3 and 7.3.4.

Because EPA evaluated two technologies for bottom ash handling conversions, EPA estimated compliance costs for both technologies for each plant except where plant-specific data were available(*e.g.*, public comments provided by plants show that an MDS could not be installed underneath the boiler due to space constraints). For these plants, EPA estimated only compliance costs associated with a remote MDS conversion. For all other plants, EPA selected the technology associated with the lowest estimated annualized cost for the combined system conversion, transport and disposal, and impoundment costs, at a plant level, as the cost basis for the plant.

EPA estimated capital, O&M, 3-, 5-, and 10-year recurring costs for MDS and remote MDS conversions using the equations described later in this section. Because the MDS and remote MDS share similar system elements, EPA calculated the O&M costs for four components.

- Shared O&M Costs – Conveyance, transport, disposal, and impoundment O&M costs applicable to both MDS and remote MDS.
- Additional Remote MDS O&M Costs – Additional O&M costs, primarily chemical costs associated with the remote MDS.
- Intermediate Storage O&M Costs – Storage O&M costs applicable to both MDS and remote MDS.
- Wet-Sluicing O&M Costs – Cost savings associated with the currently operating wet-sluicing system.

Total MDS Capital Costs = Conveyance and Intermediate Storage Equipment Costs + Direct Capital Costs + Indirect Capital Costs + Bottom Ash Disposal Costs

Conveyance and intermediate storage equipment and direct capital costs are the costs associated with purchasing and installing a fully erected and commissioned MDS, including equipment, controls, foundations, and field labor. EPA estimated equipment and direct capital costs on a generating unit basis using a relationship between capital costs and generating unit capacity (MW). EPA obtained generating unit capacity information from the Steam Electric Survey data. Vendors provided the relationship between the equipment and direct capital costs and the generating unit capacity. The conveyance and intermediate storage costs provided for the MDS system include the costs for a semi-dry silo. After calculating the capital costs at the generating unit level, EPA summed the capital costs to a plant level.

Indirect capital costs (*e.g.*, engineering, construction, and other contractor fee costs) are the costs associated with preparing a specific site for the installation of the MDS equipment and the costs required for supervising and inspecting the installation. EPA estimated indirect capital costs as a percentage of the total direct capital costs (purchased equipment costs plus direct capital costs) based on information obtained from a publicly available costing manual, *Plant Design and Economics for Chemical Engineers* (Peters and Timmerhaus, 1991). See Section 8.1.4 of the *Incremental Costs and Pollutant Removals for Final Effluent Limitations Guidelines and Standards for the Steam Electric Generating Point Source Category* report for more details on methodology for estimating the indirect capital costs [U.S. EPA, 2015a].

EPA calculated the amount of moisture-conditioned bottom ash generated from the moisture-conditioned bottom ash handling conversion using the wet bottom ash generation rate at the plant level and an average moisture content of bottom ash from the Steam Electric Survey data, supplemented with vendor data. EPA used the moisture-conditioned bottom ash tonnage to estimate the disposal costs, described in Section 9.5.3.

Total Remote MDS Capital Costs = Conveyance and Intermediate Storage Equipment Costs + Direct Capital Costs + Indirect Capital Costs + Bottom Ash Disposal Costs

Conveyance and intermediate storage equipment and direct capital costs are the costs associated with purchasing and installing a fully erected and commissioned remote MDS, including equipment, controls, foundations, and field labor. EPA estimated equipment and direct costs on a generating-unit basis using a relationship between capital costs and generating unit capacity (MW). EPA obtained generating unit capacity from the Steam Electric Survey data. Vendors provided the relationship between the equipment and direct capital costs and the generating-unit capacity. The conveyance and intermediate storage costs provided for the remote MDS system include the costs for a semidry silo. After calculating the capital costs at the generating-unit level, EPA summed the capital costs to a plant level.

EPA also estimated equipment costs associated with a recycle pump and chemical feed system. Recycle pump costs are the costs associated with purchasing a pump used to recycle the sluice water from the remote MDS back to the steam electric generating unit. The chemical feed system costs are the costs associated with purchasing a chemical feed system to adjust the pH of the bottom ash transport water, as required, to completely recycle the bottom ash sluice. To estimate the costs of the recycle pump and the chemical feed system for the remote MDS, EPA used the same type of recycle pump and chemical feed system used in the FGD chemical precipitation cost methodology. See Section 6.1.6.2 of EPA's *Incremental Costs and Pollutant Removals for Final Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category* report [U.S. EPA, 2015a]. The recycle pump and chemical feed system costs include the freight costs associated with each piece of equipment. To estimate these costs, EPA used the bottom ash sluice rate, in gpd, from the Steam Electric Survey data at a generating-unit level and summed them to the plant level. EPA obtained recycle pump and chemical feed system cost relationships and estimated freight costs from vendors.

EPA estimated additional direct capital costs, including installation and site preparation, for the recycle pump and chemical feed system for the remote MDS. EPA estimated direct capital costs associated with this equipment for each plant using a direct capital cost factor determined from Steam Electric Survey, vendor, and other industry-submitted data. EPA estimated the other direct capital costs by applying the calculated factor to the recycle pump and chemical feed system purchased equipment cost.

Indirect and disposal capital costs are calculated using the same methodology described for the total MDS capital costs.

Total Shared O&M Costs = Conveyance Operating Labor Costs + Conveyance Maintenance Labor Costs + Conveyance Maintenance Materials Costs + Conveyance Energy Costs + Bottom Ash Transportation Costs + Bottom Ash Disposal Costs + Impoundment Operation Costs

Conveyance O&M labor costs are the costs associated with operating and maintaining the conveyance portion of the bottom ash handling system. To calculate the labor rate for all system elements for the bottom ash conversion costs, EPA used the Steam Electric Survey data supplemented with U.S. Bureau of Labor Statistics data. The Agency calculated the conveyance O&M labor costs using the labor rate and the number of required operator or maintenance hours per year for operating or maintenance labor, respectively. Operating and maintenance hours per year were calculated using data in the Steam Electric Survey.

Maintenance materials costs are the costs associated with replacing equipment due to routine wear and tear. EPA used data from the Steam Electric Survey to determine a maintenance materials factor based on a comparison of maintenance material costs to the total O&M costs for the conveyance portion of the bottom ash handling system. EPA applied the median maintenance material factor to the total conveyance O&M costs to estimate the maintenance materials costs.

Energy costs are the costs associated with the power requirements for the conveyance portion of the bottom ash handling system. Vendors supplied the size and horsepower specifications for pumps for the MDS and remote MDS systems based on generating unit capacity (in MW). EPA used the vendor data to create equations for estimating the energy consumption at the plant (kWh/yr). EPA used the national 2010 energy cost of 4.05 cents per kWh to calculate the energy cost [U.S. DOE, 2011].

EPA estimated the O&M costs associated with transportation, disposal, and impoundment operations according to the methodologies described in Section 9.5. EPA used the same estimated tonnage described for the capital cost equation to estimate bottom ash transportation, disposal, and impoundment operation costs.

Total Additional Remote O&M Costs = Chemical Purchase Costs + Chemical Pump Energy Costs

Chemical purchase costs are the costs to purchase chemicals to control pH levels for bottom ash sluice recirculation. To calculate chemical purchase costs, EPA estimated the hydrochloric acid (HCl) consumption, chemical purchase, and freight costs. EPA calculated the HCl consumption using wet-sluicing data and operating days in the Steam Electric Survey data. For more explanation regarding estimating chemical consumption, see Section 6.1.7.4 in EPA's *Incremental Costs and Pollutant Removals for Final Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category* report [U.S. EPA, 2015a].

Energy requirements unique to the remote MDS consist of the energy required to operate the pump that returns sluice water from the sump pit back to the boiler area and the HCl feed pump. EPA determined this additional energy consumption (kWh/yr) by calculating and summing the annual power consumption for these two pumps for each generating unit, and then summing these generating unit-level consumptions to calculate plant-level energy consumption. Pump energy consumption (kWh/yr) is a function of pump horsepower. EPA used the national 2010 energy cost of 4.05 cents per kWh to calculate the energy cost [U.S. EPA, 2015a].

Total Intermediate Storage O&M Costs = Storage Operating Labor Costs + Storage Maintenance Labor Costs + Storage Maintenance Materials Costs + Storage Energy Costs

Intermediate storage labor costs are the costs associated with operating and maintaining the intermediate storage area where bottom ash is conveyed prior to disposal. EPA calculated intermediate storage O&M labor costs using an estimated labor rate and the number of required operator or maintenance hours per year for operating or maintenance labor, respectively. EPA used the Steam Electric Survey data supplemented with U.S. Bureau of Labor Statistics data to calculate the labor rate for all system elements for the intermediate storage costs. EPA calculated O&M hours per year using data in the Steam Electric Survey.

Maintenance materials costs are the costs associated with replacing equipment due to routine wear and tear. EPA used data from the Steam Electric Survey to determine a maintenance materials factor based on a comparison of maintenance material costs to the total O&M costs for the intermediate storage portion of the bottom ash handling system. EPA applied the median maintenance materials cost factor to the total intermediate storage O&M costs to estimate the maintenance materials costs.

Intermediate storage energy costs are the costs associated with power requirements for the pugmill unloader at the silo. EPA used vendor supplied size and horsepower specifications for pugmill unloaders to calculate the intermediate storage energy consumption (kWh/yr). EPA used the national 2010 energy cost of 4.05 cents per kWh to calculate the energy cost [U.S. EPA, 2015a].

Total Wet-Sluicing O&M Costs = Sluicing Operating Labor Costs + Sluicing Maintenance Labor Costs + Sluicing Maintenance Materials Costs + Sluicing Energy Costs

EPA estimated wet-sluicing O&M cost components to subtract them from the calculated costs to represent the incremental cost achieved by the MDS system. EPA is subtracting these O&M costs because the MDS system will no longer require the use of the wet-sluicing system after the system is installed.

The sluicing O&M labor costs are the costs associated with operating and maintaining the sluicing portion of the bottom ash handling system. EPA calculated wet-sluicing O&M labor costs using an estimated labor rate and the number of required operator or maintenance hours per year for operating or maintenance labor, respectively. EPA used the Steam Electric Survey data supplemented with U.S. Bureau of Labor Statistics data to calculate the labor rate for all system elements for the wet-sluicing costs. EPA used industry responses from the Steam Electric Survey for wet-sluicing systems to calculate median operating worker hours per day for the conveyance portion of the system. To calculate the total O&M days per year, EPA used the number of generating unit operating days in 2009, reported in the Steam Electric Survey. EPA estimated maintenance hours per year using the maintenance labor median worker hours per year obtained from industry responses to the Steam Electric Survey.

EPA estimated maintenance materials costs based on an evaluation of O&M costs reported in the Steam Electric Survey for generating units with wet-sluicing bottom ash handling systems. EPA calculated the ratio of reported maintenance materials costs to the total sum of operating labor, maintenance labor, energy, and other O&M costs. EPA applied the median maintenance materials cost factor to the total conveyance O&M costs to estimate the maintenance materials costs.

Wet-sluicing energy costs are the costs associated with power requirements for the wet bottom ash handling system. EPA used vendor supplied size and horsepower specifications pumps to calculate energy consumption (kWh/yr). EPA used the national 2010 energy cost of 4.05 cents per kilowatt hour to calculate the energy cost [U.S. EPA, 2015a].

Total MDS O&M Costs = Shared O&M Costs + Intermediate Storage O&M Costs – Wet-Sluicing O&M Costs

As previously described, EPA estimated four different cost components to calculate total O&M costs for each system because different components apply to the two different systems. EPA estimated MDS O&M costs using the shared, intermediate storage, and wet-sluicing costs. EPA subtracted wet-sluicing cost components from the calculated costs to represent the incremental cost achieved by the MDS system.

Total Remote MDS O&M Costs = Shared O&M Costs + Additional Remote MDS O&M Costs + Intermediate Storage O&M Costs

Total O&M costs for the remote MDS system include the shared and intermediate storage costs; however, EPA also included additional costs for operating the recycle pump and chemical feed system to allow for complete recycle. EPA did not subtract wet-sluicing O&M costs from the remote MDS costs because the system still includes the existing sluicing operations.

Total 3-Year Recurring Costs = Cost of Mechanical Drag Chain for MDS

EPA calculated 3-year recurring costs associated with the drag chain for the MDS. The drag chain is the component of the system that drags the bottom ash from the water bath, up the incline to intermediate storage. EPA calculated the 3-year recurring cost by determining the cost and expected life of a drag chain for the MDS. Because the drag chain is located underneath the boiler, and more susceptible to large chunks of falling bottom ash, EPA determined that the expected life of a MDS drag chain is 3 years. The generating unit can continue to operate during the replacement of the drag chain components.

Total 5-Year Recurring Costs = Cost of Mechanical Drag Chain for Remote MDS + Cost of Rental Tank for Remote MDS Maintenance

EPA calculated 5-year recurring costs associated with the drag chain for the remote MDS and rental tanks associated with remote MDS maintenance. The drag chain component for the remote MDS is the same as that described for the MDS. EPA calculated the 5-year recurring cost by determining the cost and expected life of a drag chain for the remote MDS. Because the drag chain of the remote MDS system is not located directly underneath the boiler, and is less likely to be damaged by falling bottom ash, EPA determined that the expected life of a remote MDS drag chain is 5 years. The generating unit can continue to operate during the replacement of the drag chain components.

Based on vendor data, EPA determined that wear plates at the bottom ash remote MDS conveyance systems may need to be replaced every 5 years. EPA estimated 5-year costs associated with renting additional surge tank capacity so that the water in the remote MDS can be drained and stored during this maintenance, if necessary. These rental tank costs were estimated based on the bottom ash transport water volume estimated to be in the remote MDS and sluice pipeline. EPA estimated remote MDS volume based on a relationship, from vendor data, between design bottom ash tonnage and volume (in gallons). EPA estimated pipe volume based on a relationship, from vendor data, between generating unit capacity (in MW) and pipe diameter. EPA used bottom ash design tonnage and generating unit capacity from the Steam Electric Survey data. EPA used the distance to ponds reported in the Steam Electric Survey to estimate the length of sluice piping at the plant. The rental tank costs include the tanks, delivery costs, and hose, pump, and fitting rentals.

Bottom Ash Management Costs = Engineering Consulting Cost + Total Capital Chemical Feed System Cost + Total O&M Chemical Feed System Cost

EPA also identified several plants that operate bottom ash wet-sluicing systems predominantly as closed-loop systems. These plants did not discharge bottom ash transport water in 2009. However, based on data in the Steam Electric Survey, EPA determined that these plants have the ability to discharge bottom ash transport water from emergency outfalls. Although these plants did not discharge bottom ash transport water in 2009, EPA still determined it may be appropriate to estimate a one-time cost associated with consulting an engineer to completely close the bottom ash recycle system, eliminating the potential for future discharges of bottom ash transport water. In addition, EPA estimated capital and O&M costs associated with a chemical feed system for all generating units at a plant currently operating wet-sluicing systems. EPA used the same equations as the remote MDS methodology to estimate capital and O&M costs associated with a chemical feed system for the plant. See Section 8.5 of EPA's *Incremental Costs and Pollutant Removals for Final Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category* report [U.S. EPA, 2015a].

9.7.3 Estimated Industry-Level Costs for Ash Handling Conversions

Table 9-7 presents the estimated capital, O&M, and recurring costs on an industry level associated with dry fly ash handling conversions. The table also includes the number of plants incurring compliance costs. The costs presented in the table represent the compliance costs for those generating units facing more stringent requirements under the final rule than exist under the previously established regulations; therefore, oil-fired generating units and generating units with a capacity of 50 MW or less are not included because they do not to need meet any more stringent requirements than already exist under BPT regulations. See EPA's *Incremental Costs and Pollutant Removals for Final Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category* report for the costs for all generating units [U.S. EPA, 2015a]. Table 9-8 adjusts the results shown in Table 9-7, accounting for the expected closures related to the implementation of the CPP.

Table 9-7. Estimated Industry-Level Costs for Fly Ash Handling Conversions Based on Oil-Fired Units and Units 50 MW or Less Not Installing Technology Basis

Number of Plants	Total Capital Cost ($)	Total O&M Cost ($/year) [a]	10-Year Recurring Cost ($/10-year) [a]
19	$180,000,000	($720,000)	($4,300,000)

Note: Costs are rounded to three significant figures.

Note: All costs are indexed to 2010 dollars using RSMeans Historical Cost Indices [RSMeans, 2015].

a – The values in this column are negative, and presented in parenthesis, because they represent cost savings.

Table 9-8. Estimated Industry-Level Costs for Fly Ash Handling Conversions Based on Oil-Fired Units and Units 50 MW or Less Not Installing Technology Basis, Accounting for CPP

Number of Plants	Total Capital Cost ($)	Total O&M Cost ($/year) [a]	10-Year Recurring Cost ($/10-year) [a]
16	$135,000,000	($573,000)	($3,300,000)

Note: Costs are rounded to three significant figures.

Note: All costs are indexed to 2010 dollars using RSMeans Historical Cost Indices [RSMeans, 2015].

a – The values in this column are negative, and presented in parenthesis, because they represent cost savings.

Table 9-9 presents the estimated capital, O&M, and recurring costs at an industry level associated with dry or closed-loop recycle bottom ash handling conversions. The table also includes the number of plants incurring compliance costs. The costs presented in the table represent the compliance costs for those generating units facing more stringent requirements under the final rule than exist under the previously established regulations; therefore, oil-fired generating units and generating units with a capacity of 50 MW or less are not included because they do not need to meet any more stringent requirements than already exist under BPT regulations. See EPA's *Incremental Costs and Pollutant Removals for Final Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category* report for the costs for all generating units [U.S. EPA, 2015a]. Table 9-10 adjusts the results shown in Table 9-9, accounting for the expected closures related to the implementation of the CPP.

Table 9-9. Estimated Industry-Level Costs for Bottom Ash Handling Conversions Based on Oil-Fired Units and Units 50 MW or Less Not Installing Technology Basis

Number of Plants	Total Capital Cost ($)	Total O&M Cost ($/year)	One-Time Cost ($)	3-Year Recurring Cost ($/3-year)	5-Year Recurring Cost ($/5-year)	10-Year Recurring Cost ($/10-year) [a]
141	$3,460,000,000	$203,000,000	$202,000	$3,680,000	$48,800,000	($51,500,000)

Note: Costs are rounded to three significant figures.

Note: All costs are indexed to 2010 dollars using RSMeans Historical Cost Indices [RSMeans, 2015].

a – The values in this column are negative, and presented in parenthesis, because they represent cost savings.

Table 9-10. Estimated Industry-Level Costs for Bottom Ash Handling Conversions Based on Oil-Fired Units and Units 50 MW or Less Not Installing Technology Basis, Accounting for CPP

Number of Plants	Total Capital Cost ($)	Total O&M Cost ($/year)	One-Time Cost ($)	3-Year Recurring Cost ($/3-year)	5-Year Recurring Cost ($/5-year)	10-Year Recurring Cost ($/10-year) [a]
103	$2,520,000,000	$133,000,000	$179,000	$2,450,000	$32,000,000	($38,300,000)

Note: Costs are rounded to three significant figures.

Note: All costs are indexed to 2010 dollars using RSMeans Historical Cost Indices [RSMeans, 2015].

a – The values in this column are negative, and presented in parenthesis, because they represent cost savings.

Under Regulatory Option C, EPA would have established zero discharge requirements for bottom ash transport water only for units greater than 400 MW. Therefore, EPA also estimated the industry-level costs for plants to convert only the generating units that are 400 MW or greater to dry or closed-loop recycle bottom ash handling. Table 9-11 presents the estimated capital, O&M, and recurring costs on an industry level associated with dry or closed-loop recycle bottom ash handling conversions for this analysis. Table 9-11 does not include costs for oil-fired generating units and generating units with a capacity of less than or equal to 400 MW because they would not need to meet any more stringent requirements than already existed under BPT regulations. Table 9-12 adjusts the results shown in Table 9-11, accounting for the expected closures related to the implementation of the CPP.

Table 9-11. Estimated Industry-Level Costs for Bottom Ash Handling Conversions Based on Oil-Fired Units and Units Less than 400 MW Not Installing Technology Basis

Number of Plants	Total Capital Cost ($)	Total O&M Cost ($/year)	One-Time Cost ($)	3-Year Recurring Cost ($/3-year)	5-Year Recurring Cost ($/5-year)	10-Year Recurring Cost ($/10-year) [a]
78	$2,290,000,000	$97,100,000	$112,000	$0	$24,300,000	($29,400,000)

Note: Costs are rounded to three significant figures.

Note: All costs are indexed to 2010 dollars using RSMeans Historical Cost Indices [RSMeans, 2015].

a – The values in this column are negative, and presented in parenthesis, because they represent cost savings.

Table 9-12. Estimated Industry-Level Costs for Bottom Ash Handling Conversions Based on Oil-Fired Units and Units Less than 400 MW Not Installing Technology Basis, Accounting for CPP

Number of Plants	Total Capital Cost ($)	Total O&M Cost ($/year)	One-Time Cost ($)	3-Year Recurring Cost ($/3-year)	5-Year Recurring Cost ($/5-year)	10-Year Recurring Cost ($/10-year) [a]
61	$1,820,000,000	$77,600,000	$89,700	$0	$18,800,000	($23,000,000)

Note: Costs are rounded to three significant figures.

Note: All costs are indexed to 2010 dollars using RSMeans Historical Cost Indices [RSMeans, 2015].

a – The values in this column are negative, and presented in parenthesis, because they represent cost savings.

9.8 COMBUSTION RESIDUAL LANDFILL LEACHATE

EPA estimated capital and O&M costs associated with installing and operating a chemical precipitation wastewater treatment system to treat combustion residual landfill leachate. Note that as described in Section 9.2.4, EPA determined that plants with combustion residual surface impoundment leachate will not incur costs associated with any final leachate requirements because plants will likely use a different approach than installing the technology basis to comply with requirements based on the chemical precipitation technology option. EPA calculated the cost for a stand-alone chemical precipitation system to treat the landfill leachate using the equations in Sections 9.6.1 associated with chemical precipitation treatment of FGD wastewater [ERG, 2015a].

Table 9-13 presents the estimated capital and O&M costs on an industry level associated with treating combustion residual landfill leachate. The table also includes the number of plants incurring compliance costs. The costs presented in the table represent the compliance costs for those plants facing more stringent requirements under the technology option e than exist under the previously established regulations; therefore, plants operating only oil-fired generating units and/or generating units with a capacity of 50 MW or less are not included because they do not need to meet any more stringent requirements than already existed under BPT regulations. See EPA's *Incremental Costs and Pollutant Removals for Final Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category* report for the costs for all generating units. [U.S. EPA, 2015a]. Table 9-14 adjusts the results shown in Table 9-13, accounting for the expected closures related to the implementation of the CPP.

Table 9-13. Estimated Industry-Level Costs for the Chemical Precipitation Technology Option for Combustion Residual Leachate Based on Oil-Fired Units and Units 50 MW or Less Not Installing Technology Basis

Technology Option	Number of Plants	Total Capital Cost ($)	Total O&M Cost ($/year)	6-Year Recurring Cost ($/6-year)	10-Year Recurring Cost ($/10-year)
Chemical Precipitation	82	$605,000,000	$34,300,000	$7,000,000	$0

Note: Costs are rounded to three significant figures.

Note: All costs are indexed to 2010 dollars using RSMeans Historical Cost Indices [RSMeans, 2015].

Table 9-14. Estimated Industry-Level Costs for the Chemical Precipitation Technology Option for Combustion Residual Leachate Based on Oil-Fired Units and Units 50 MW or Less Not Installing Technology Basis, Accounting for CPP

Technology Option	Number of Plants	Total Capital Cost ($)	Total O&M Cost ($/year)	6-Year Recurring Cost ($/6-year)	10-Year Recurring Cost ($/10-year)
Chemical Precipitation	60	$478,000,000	$28,600,000	$5,120,000	$0

Note: Costs are rounded to three significant figures.

Note: All costs are indexed to 2010 dollars using RSMeans Historical Cost Indices [RSMeans, 2015].

9.9 GASIFICATION WASTEWATER

EPA estimated capital and O&M costs associated with installing and operating an evaporation treatment system for gasification wastewater. As described in Section 7.6, EPA identified three plants currently operating IGCC generating units by 2014. All three of these plants operate the technology option selected as BAT, evaporation. Because these three plants already operate the BAT technology basis, EPA estimated a capital cost of zero. EPA estimated only costs associated with compliance monitoring described in Section 9.5

Table 9-15 presents the estimated capital and O&M costs on an industry level associated with treating gasification wastewater. The table also includes the number of plants incurring compliance costs. See EPA's *Incremental Costs and Pollutant Removals for Final Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category* report for the costs for all generating units. [U.S. EPA, 2015a] Table 9-16 adjusts the results shown in Table 9-15, accounting for the expected closures related to the implementation of the CPP.

Table 9-15. Estimated Industry-Level Costs for Gasification Wastewater

Technology Option	Number of Plants	Total Capital Cost ($)	Total O&M Cost ($/year)	6-Year Recurring Cost ($/6-year)	10-Year Recurring Cost ($/10-year)
Evaporation	3	$0	$192,000	$0	$0

Note: Costs are rounded to three significant figures.

Note: All costs are indexed to 2010 dollars using RSMeans Historical Cost Indices [RSMeans, 2015].

Table 9-16. Estimated Industry-Level Costs for Gasification Wastewater, Accounting for CPP

Technology Option	Number of Plants	Total Capital Cost ($)	Total O&M Cost ($/year)	6-Year Recurring Cost ($/6-year)	10-Year Recurring Cost ($/10-year)
Evaporation	2	$0	$128,000	$0	$0

Note: Costs are rounded to three significant figures.

Note: All costs are indexed to 2010 dollars using RSMeans Historical Cost Indices [RSMeans, 2015].

9.10 SUMMARY OF NATIONAL ENGINEERING COSTS

As described in Section 8, EPA evaluated six main regulatory options comprised of various combinations of the technology options considered for control of each wastestream, as shown in Table 9-17. The Agency estimated the costs associated with steam electric power plants to achieve compliance with each of the main regulatory options. Table 9-18 summarizes the total estimated compliance costs (including capital costs, annual O&M costs, one-time costs, and recurring costs) associated with each regulatory option. See the *Regulatory Impact Analysis for Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (EPA-821-R-15-004)* for a list of total annualized costs by regulatory option. All cost estimates in this section are expressed in terms of pre-tax 2010 dollars. The costs presented in the table represent the compliance costs for those plants facing more stringent requirements under the final rule than exist under the previously established regulations; therefore, oil-fired generating units and generating units with a capacity of 50 MW or less are not included because they do not need to meet any more stringent requirements than already existed under BPT regulations. Under Regulatory Option C, generating units that discharge bottom ash transport water with a capacity of less than or equal to 400 MW are not included because they would not need to meet any more stringent requirements than already existed under BPT regulations. See EPA's *Incremental Costs and Pollutant Removals for Final Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category* report for the costs for all generating units [U.S. EPA, 2015a]. Table 9-19 adjusts the results shown in Table 9-18, accounting for the expected closures related to the implementation of the CPP.

Table 9-17. Technology Options and Other Costs Included in the Estimated Compliance Costs for Each Regulatory Option

Wastestream	Technology Option	Regulatory Option					
		A	B	C	D	E	F [a]
FGD Wastewater	Chemical Precipitation	✓	✓	✓	✓	✓	✓
	Biological Treatment		✓	✓	✓	✓	
	Evaporation						✓
Fly Ash Transport Water	Dry Fly Ash Handling	✓	✓	✓	✓	✓	✓
Bottom Ash Transport Water	Dry or Closed-loop Recycle Bottom Ash Handling			✓ [b]	✓	✓	✓
Leachate	Chemical Precipitation					✓	✓
Gasification Wastewater	Evaporation	✓	✓	✓	✓	✓	✓
Flue Gas Mercury Control Wastes	Dry Handling	✓	✓	✓	✓	✓	✓

Table 9-17. Technology Options and Other Costs Included in the Estimated Compliance Costs for Each Regulatory Option

Wastestream	Technology Option	Regulatory Option					
		A	B	C	D	E	F [a]
Other Costs Not Specific to Wastestream							
	Solids Transportation	✓	✓	✓	✓	✓	✓
	Solids Disposal	✓	✓	✓	✓	✓	✓
	Impoundment Operation	✓	✓	✓	✓	✓	✓
	Compliance Monitoring	✓	✓	✓	✓	✓	✓

a – During development of the final rule, EPA decided not to base the final rule on Option F for existing sources due primarily to the high cost of that Option, particularly in light of the costs associated with other rulemakings expected to impact the steam electric industry (see Section VIII.C.1 of the preamble). As a result, EPA chose not to conduct particular analyses for Option F to the same extent that it did for some of the other options considered.

b – Under Regulatory Option C, EPA would have established zero discharge requirements for bottom ash transport water only for units greater than 400 MW.

Table 9-18. Cost of Implementation by Regulatory Option [In millions of pre-tax 2010 dollars]

Regulatory Option	Number of Plants	Capital Cost	Annual O&M Cost	One-Time Costs	Recurring Costs			
					3-year	5-year	6-year	10-year [a]
A	100	$1,069	$78	$0	$0	$0	$7	($25)
B	100	$1,969	$123	$0	$0	$0	$7	($25)
C	139	$4,258	$220	$0.1	$0	$24	$7	($54)
D	181	$5,426	$326	$0.2	$4	$49	$7	($76)
E	196	$6,031	$360	$0.2	$4	$49	$14	($76)

a – The values in this column are negative, and presented in parenthesis, because they represent cost savings.

Table 9-19. Cost of Implementation by Regulatory Option [In millions of pre-tax 2010 dollars] Accounting for CPP

Regulatory Option	Number of Plants	Capital Cost	Annual O&M Cost	One Time Costs	Recurring Costs			
					3-year	5-year	6-year	10-year [a]
A	79	$910	$67	$0	$0	$0	$6	($19)
B	79	$1,640	$103	$0	$0	$0	$6	($19)
C	108	$3,462	$180	$0.1	$0	$19	$6	($42)
D	134	$4,161	$235	$0.2	$3	$32	$6	($58)
E	145	$4,638	$264	$0.2	$3	$32	$11	($58)

a – The values in this column are negative, and presented in parenthesis, because they represent cost savings.

The compliance costs for each regulatory option presented in Table 9-18 and Table 9-19 exclude generating unit retirements, repowerings, and conversions that have been announced by companies and are scheduled to occur by the time the units would have to meet any new requirements, based on information obtained by EPA as of August 2014. But they do not reflect additional planned generating unit retirements, repowerings, and conversions that have been announced since August 2014, (see [ERG, 2015d], "Memorandum to the Steam Electric Rulemaking Record: Changes to Industry Profile for Steam Electric Generating Units for the Steam Electric Effluent Guidelines Final Rule"). EPA conducted a sensitivity analysis to determine how these additional changes in the Steam Electric industry would reduce the total annualized compliance costs for the rule. The results of this analysis are presented in the "Memorandum to the Steam Electric Rulemaking Record: Changes to Industry Profile for Steam Electric Generating Units for the Steam Electric Effluent Guidelines Final Rule."

9.11 COMPLIANCE COSTS FOR NEW SOURCES

EPA evaluated the expected costs of compliance for new sources. The construction of new generating units may occur at an existing power plant or at a new plant construction site. The costs to meet NSPS or PSNS for new sources are those incremental costs to install and operate technology options compared to what a typical new source would do in absence of a requirement associated with a technology option.

The incremental costs associated with complying with the NSPS and PSNS options named for the final rule vary depending on the types of processes, wastestreams, and waste management systems that would have been installed in the absence of the new source requirements. EPA estimated capital and O&M costs for nine different scenarios that represent the different types of operations that are present at existing power plants or are typically included at new power plants. These scenarios captured differences in the following characteristics:

- Plant status (*i.e.*, greenfield versus existing plant).
- Presence/capacity of on-site impoundments.
- Presence/capacity of on-site landfills.
- Type of FGD system in service.
- Bottom ash handling.
- Combustion residual leachate collection and handling.

Although EPA evaluated nine different scenarios based on various combinations of the elements discussed above, it determined that two of the scenarios best represent the conditions that would likely be present at new sources. One scenario reflects conditions for a greenfield plant and the other scenario reflects conditions for a new source constructed at an existing plant. EPA selected the scenarios that most resembled current industry practices, based on an evaluation of the industry profile, for use in the NSPS analysis. Table 9-20 identifies the plant and genearating unit characteristics that were used for these two scenarios. See the "Steam Electric NSPS Costs Methodology" [ERG, 2015e] for a description of the other scenarios evaluated as part of the NSPS analysis.

Table 9-20. NSPS Compliance Cost Scenarios Evaluated for the Rule

Scenario Characteristics		Existing Plant	Greenfield Plant
Plant-Level Characteristics	Plant Status	Existing	Greenfield
	Presence of On-Site Impoundments	On-site impoundment with no additional capacity	No on-site impoundment
	Presence of On-Site Landfill	On-site landfill with available capacity	On-site landfill to be installed
New Generating Unit-Level Characteristics	Type of FGD System	Wet FGD system (impoundments as treatment)	Wet FGD system (impoundments as treatment)
	Bottom Ash Handling	Mechanical drag system already planned	Mechanical drag system already planned
	Fly Ash Handling [a]	Dry	Dry
	Combustion Residual Leachate [b]	No leachate collection in the landfill	Landfill leachate collected but not treated
NSPS Costs	FGD	Yes	Yes
	Bottom Ash [c]	No	No
	Fly Ash [a]	No	No
	Combustion Residual Leachate	No	Yes

a – All scenarios assume dry fly ash handling because of the current NSPS regulations (40 CFR 423.15(g)).

b – Because the greenfield plant includes leachate collection while the existing plant does not (because leachate at the existing plant would likely be subject to BAT), the costs presented in Table 9-21 are more expensive for the greenfield plant than for the existing plant.

c – EPA assumed that all new units (at both new and existing plants) will install a MDS to handle bottom ash regardless of the ELGs based on information provided in the Steam Electric Survey. Additional information is provided in Section 6 of the "Steam Electric NSPS Costs Methodology" [ERG, 2015e].

EPA evaluated new source costs for FGD wastewater, bottom ash transport wastewater, and combustion residual leachate. Because the current Steam Electric NSPS already require zero discharge for fly ash transport wastewater, EPA did not calculate new source costs for fly ash transport water. Additionally, because the technology bases for gasification wastewater and FGMC wastewater are already standard industry practices, EPA did not calculate new source costs for these wastestreams.

Additionally, EPA determined that the majority of plants that install bottom ash handling systems in the last 20 years installed dry handling systems (approximately 80 percent). Therefore, EPA determined new source incremental compliance costs for dry bottom ash handling would be zero [ERG, 2015e].

In addition to calculating the compliance costs for these two different scenarios, EPA also evaluated the costs for three different model-sized generating units (*i.e.*, small, medium, and large generating units). Table 9-21 presents the estimated capital and O&M costs for each regulatory option and each model plant size. The estimated incremental compliance costs for each of scenarios evaluated by EPA are included in the memorandum entitled "Steam Electric NSPS Costs Methodology."

Table 9-21. Estimated Industry-Level NSPS Costs

Regulatory Option	Small Unit (350 MW)		Medium Unit (600 MW)		Large Unit (1,300 MW)	
	Total Capital Cost ($)	Total O&M Cost ($/year)	Total Capital Cost ($)	Total O&M Cost ($/year)	Total Capital Cost ($)	Total O&M Cost ($/year)
Greenfield Plant						
A	[a]	[a]	[a]	[a]	[a]	[a]
B	14,700,000	992,000	19,000,000	1,360,000	32,700,000	2,420,000
C	14,700,000	992,000	19,000,000	1,360,000	32,700,000	2,420,000
D	14,700,000	992,000	19,000,000	1,360,000	32,700,000	2,420,000
E [b]	20,000,000	1,200,000	25,000,000	1,600,000	39,000,000	2,800,000
F [b]	69,000,000	4,700,000	78,000,000	6,200,000	110,000,000	11,000,000
Existing Plant						
A	[a]	[a]	[a]	[a]	[a]	[a]
B	14,700,000	992,000	19,000,000	1,360,000	32,700,000	2,420,000
C	14,700,000	992,000	19,000,000	1,360,000	32,700,000	2,420,000
D	14,700,000	992,000	19,000,000	1,360,000	32,700,000	2,420,000
E [b]	15,000,000	1,000,000	19,000,000	1,400,000	33,000,000	2,500,000
F [b]	64,000,000	4,500,000	73,000,000	5,900,000	100,000,000	10,000,000

Source: [ERG, 2015e].

Note: Costs are rounded to three significant figures.

Note: All costs are indexed to 2010 dollars using RSMeans Historical Cost Indices [RSMeans, 2015].

a – The NSPS costs for Regulatory Option A have been withheld to protect confidential business information.

b – The NSPS costs for Regulatory Options E and F have been rounded up to two significant figured to protect confidential business information.

9.12 References

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SECTION 10
POLLUTANT LOADINGS AND REMOVALS

This section discusses annual pollutant loadings for the steam electric power generating industry and pollutant removal estimates associated with the final rule, as well as several other regulatory options. EPA defined baseline and post-compliance pollutant loadings as follows:

- *Baseline Loadings*. Pollutant loadings, in pounds per year, in steam electric wastewater being discharged to surface water or through publicly owned treatment works (POTWs) to surface water.
- *Post-Compliance Loadings*. Estimated pollutant loadings, in pounds per year, in steam electric wastewater after implementation of the technology option. These are also referred to as treated loadings. EPA calculated these loadings assuming that all steam electric power plants subject to the requirements would install and operate wastewater treatment and pollution prevention technologies equivalent to the technology bases for the regulatory options.
- *Pollutant Removals*. The difference between the baseline loadings and post-compliance loadings for each regulatory option.

Some aspects of the final effluent limitations guidelines and standards (ELGs) (*e.g.*, applicability changes) will likely not lead to a change in pollutant loadings for complying plants. Other aspects of the ELGs will likely lead to a change in pollutant loadings for a subset of complying plants. These plants generally generate the wastestreams for which EPA is establishing new effluent limitations or standards. This section describes the detailed pollutant loadings evaluation EPA performed for these plants that are likely to reduce pollutant loadings associated with the ELGs, as well as other regulatory options named. Specifically, EPA determined baseline and post-compliance pollutant loadings for FGD wastewater, fly ash transport water, bottom ash transport water, combustion residual leachate (impoundment and landfill), gasification wastewater, and flue gas mercury control (FGMC) wastewater.

The currently operating gasification generating units use evaporation systems, which is the technology basis for the ELGs. Therefore, EPA determined that the gasification wastewater baseline loadings are equal to the post-compliance loadings. Similarly, plants currently manage their FGMC wastes so there is no pollutant discharge to surface waters and therefore the FGMC wastewater baseline and post-compliance loadings are also equal. The remainder of this section applies to FGD wastewater, fly ash transport water, bottom ash transport water, and combustion residual leachate.

10.1 GENERAL METHODOLOGY FOR ESTIMATING POLLUTANT REMOVALS

For each plant discharging an evaluated wastestream (*i.e.*, FGD wastewater, ash transport water, and combustion residual leachate), EPA calculated plant-level pollutant removals for each of the technology options discussed in Section 8. For example, for any plant discharging FGD wastewater, EPA calculated both a baseline loading and post-compliance loadings associated with two technology bases (*i.e.*, chemical precipitation and chemical precipitation with biological treatment). EPA did not evaluate post-compliance loadings associated with chemical precipitation followed by evaporation because EPA decided not to base the control of pollutants in FGD wastewater for existing sources on this technology due to the high cost.[112] On a plant-level basis, EPA calculates baseline loadings by multiplying the average pollutant concentration in the discharge by the plant-specific wastewater discharge flow rate to generate the mass of pollutant discharged per year, in pounds/year.

EPA used sampling data gathered through its sampling program described in Section 3, the *Questionnaire for the Steam Electric Power Generating Effluent Guidelines* (Steam Electric Survey), public comment, industry-submitted data, and publicly available sources to characterize the baseline loading and post-compliance loading concentrations for each evaluated wastestream. Section 10.2 presents the data sources and average discharge pollutant concentrations for baseline and each of the technology options associated with the evaluated wastestreams.

Next, for each evaluated wastestream discharged by a specific plant, EPA used data from the Steam Electric Survey or industry-submitted data to determine the plant's discharge flow rate. In cases where these data were insufficient, EPA developed a methodology for estimating flow rates. As discussed in Section 9.4.1, EPA also adjusted the baseline, specifically the plant-specific discharge flow rates for the pollutant loading estimates, to account for announced plans to retire a generating unit or alter operations that would eliminate the discharge of an applicable wastestream.[113] The Agency also adjusted for other rulemakings, including the coal combustion residual (CCR) rule and the Clean Power Plan (CPP). Section 10.3 provides details on these wastewater flow rates.

EPA calculated baseline pollutant loadings and post-compliance loadings for each plant discharging an evaluated wastestream using the plant-specific wastewater flow for the wastestream and average pollutant concentration of the specific wastestream in the following equation:

$$\text{Loading}_{\text{pollutant}}\left(\frac{\text{lbs}}{\text{yr}}\right) = \text{FlowRate}\left(\frac{\text{gallons}}{\text{day}}\right) \times \text{Discharge days}\left(\frac{\text{days}}{\text{year}}\right) \times \text{Conc}_{\text{pollutant}}\left(\frac{\text{ug}}{\text{L}}\right) \times \left(\frac{2.20462\ \text{lb}}{10^9\ \text{ug}}\right) \times \left(\frac{1000\ \text{L}}{264.17\ \text{gallons}}\right)$$

Where:

$\text{Loading}_{\text{pollutant}}$	=	The loadings from a specific pollutant discharged directly to surface water, in pounds per year.

[112] EPA did evaluate characterization data for chemical precipitation followed by evaporation in order to estimate pollutant loadings associated with those steam electric power plants currently operating this type of treatment for FGD wastewater as part of baseline loadings.

[113] EPA determined that there would be no baseline pollutant loadings and no associated pollutants removals attributable to the ELGs for steam electric generating units that have announced plans to retire, convert to a noncoal fuel source, or change/upgrade ash handling practices by the time that the steam electric generating units have to meet the ELGs. See the *Changes to Industry Profile for Steam Electric Generating Units for the Steam Electric Effluent Guidelines Final Rule* [ERG, 2015c] for a list of the plants and generating units that were identified as retiring, converting to a noncoal fuel, or changing/upgrading ash handling practices.

FlowRate	=	The flow rate of the wastestream being discharged, in gallons per day.
Discharge Days	=	The number of days per year wastewater is discharged.
$Conc_{pollutant}$	=	The average concentration of a specific pollutant present in the wastestream, in micrograms per liter.

EPA identified several plants that report transferring wastewater to a POTW rather than discharging directly to surface water. For these plants, EPA adjusted the baseline loadings to account for pollutant removals expected from POTWs for each analyte. For each pollutant of concern (POC), identified by wastestream in Section 6.6, Table 10-1 provides the percent removals expected from well-operated POTWs as reported in the "Memorandum to the 2006 Effluent Guidelines Program Plan Docket" [ERG, 2005]. For any plant identified as discharging a wastestream to a POTW, EPA used the calculated baseline loadings (or post-compliance loadings) and the values shown in Table 10-1 to calculate the amount of pollutant discharged from the POTW to surface water according to the following equation:

$$\text{Loading}_{\text{pollutant\_indirect}}\left(\frac{\text{lbs}}{\text{yr}}\right)=\text{Loading}_{\text{pollutant}}\left(\frac{\text{lbs}}{\text{yr}}\right)\times(1\text{-POTWRemoval})$$

Where:

$Loading_{pollutant\_indirect}$	=	The loadings from a specific pollutant that is transferred to a POTW prior to discharge, in pounds/year.
$Loading_{pollutant}$	=	The loadings from a specific pollutant if it were discharged directly, in pounds/year.
POTWRemoval	=	The estimated percentage of the pollutant loading that will be removed by a POTW.

In addition to expressing pollutant loadings in pounds of pollutant discharged per year, EPA uses toxic weighting factors (TWFs) to account for differences in toxicity across pollutants. A list of the TWFs used for this rulemaking can be found in EPA's memorandum "Review of Toxic Weighting Factors in Support of the Final Steam Electric Effluent Limitations Guidelines and Standards" [ERG, 2015e]. EPA calculated a toxic-weighted pound-equivalent (TWPE) value for each pollutant discharged to compare mass loadings of different pollutants based on their toxicity. To perform this comparison, EPA multiplied the mass loadings of pollutant in pounds/year by the pollutant-specific TWF to derive a "toxic-equivalent" loading (lb-equivalent/yr), or TWPE.[114] Section 10.4 discusses the wastestream mass loading (*i.e.*, unweighted loadings) and TWPE loadings in more detail.

[114] If the wastestream was discharged to a POTW, EPA adjusted the TWPE to account for POTW removals, as described above.

Table 10-1. POTW Removals

Analyte	Median POTW Removal Percentage
Aluminum	91.0%
Ammonia	39.0%
Antimony	66.8%
Arsenic	65.8%
Barium	55.2%
Beryllium	61.2%
Biochemical Oxygen Demand	NA
Boron	NA
Cadmium	90.1%
Calcium	NA
Chemical Oxygen Demand	NA
Chloride	NA
Chromium	80.3%
Hexavalent Chromium	NA
Cobalt	10.2%
Copper	84.2%
Cyanide, Total	NA
Iron	NA
Lead	77.5%
Magnesium	NA
Manganese	40.6%
Mercury	90.2%
Molybdenum	NA
Nickel	51.4%
Nitrate Nitrite as N	90.0%
Nitrogen, Kjeldahl	NA
Phosphorus, Total	NA
Selenium	34.3%
Silver	88.3%
Sodium	NA
Sulfate	NA
Thallium	53.8%
Tin	NA
Titanium	NA
Total Dissolved Solids	NA
Total Suspended Solids	NA

Table 10-1. POTW Removals

Analyte	Median POTW Removal Percentage
Vanadium	8.3%
Zinc	79.1%

Source: Memorandum to 2006 Effluent Guidelines Program Plan Docket [ERG, 2005].
NA – Not applicable.

10.2 WASTESTREAM POLLUTANT CHARACTERIZATION AND DATA SOURCES

As discussed earlier, loadings calculations require pollutant concentrations to determine the mass pollutant loadings. EPA's loadings calculations generally build off the POC analysis described in Section 6.6; pollutant loadings are only evaluated for those pollutants identified as POCs for a specific wastestream.[115] EPA used a variety of data sources to generate characterization data for the POCs in each evaluated wastestream. EPA used similar data collection criteria for data used in loadings calculations as was used for the data to determine POCs, the only difference being that data used for loadings represents treated effluent wastewater while POC data generally used untreated wastewater data. EPA subjected treated effluent data for pollutant loadings to the data quality review criteria for sampling data, Steam Electric Survey data, and secondary data, as described in "Development Memorandum for Steam Electric Analytical Database for the Final Rule" [ERG, 2015d]. EPA reviewed each data source to determine if the data met EPA's criteria for use in characterizing treated effluent. The following general criteria applied across all wastestreams:

- Sample results must contain sufficient information (*i.e.*, contain method detection limits or quantitation limits, provide units).
- Sample locations must be unambiguous and clearly described such that it can be categorized by type (*e.g.*, bottom ash pond effluent rather than pond effluent with no further definition) and level of treatment.
- Sample must be representative of typical full-scale plant operations (*e.g.*, not a simulated sample of partially treated wastewater).
- Sample analysis must be completed using accepted analytical methods for untreated wastewater.
- Data must not be duplicative of other accepted data. Where duplicate data exists (*e.g.*, submitted by a trade association representing individual plants and also submitted by the individual plant), EPA used only accepted data collected from the individual plant.
- For biphasic samples (*i.e.*, those with solids content greater than 1 percent), sample analysis must provide results for both phases.

[115] EPA also calculates pollutant loadings for combined ash impoundment effluent, as described in Section 10.2.2. In this case, the pollutant loadings were not based on the POC analysis, because there are no data available on combined ash transport water outside of impoundment data. In this situation, EPA used all pollutants detected to calculate pollutant loadings associated with combined ash impoundments.

The following subsections discuss the data used to characterize each of the regulated wastestreams, and where relevant, any additional data editing criteria EPA applied to develop the data set used for the analysis. EPA generated a separate set of characterization data for baseline and each post-compliance technology basis. Sections 10.2.1 through 10.2.3 present the data sources and characterization for FGD wastewater, ash transport water, and combustion residual leachate, respectively, and any additional data quality criteria used for each individual wastestream.

10.2.1 FGD Wastewater Characterization

EPA evaluated effluent data for chemical precipitation, chemical precipitation with biological treatment, and chemical precipitation with evaporation to characterize the baseline discharges for plants discharging FGD wastewater. Table 10-2 summarizes the data sources that met data quality criteria and EPA included in the baseline and post-compliance FGD loadings analysis. EPA reviewed all available effluent data from the sources listed in Table 10-2 and excluded data that were not usable for developing effluent characterization data for the following reasons:

- Data from commissioning or decomissioning periods.
- Data collected during periods of atypical operation, as identified by the plant.
- Data collected using analytical methods not sufficiently sensitive.[116]

See *Analytical Database Development for the Final Steam Effluent Guidelines (ELG) Rule* [ERG, 2015f] for more detail on data exclusions and data quality criteria specific to FGD wastewater.

Additionally, EPA performed the following review, made substitutions as appropriate, and performed the following analyses with the sampling data results, where appropriate, prior to using them in the technology option loadings calculations[117]:

- J-Values and Nondetects: The laboratories performing the metals analyses provided all the analytical results that were measured above the sample-specific method detection limit (MDL). Therefore, the laboratory results include values flagged with a "J" indicator (*i.e.*, results measured above the method detection limit, but below the quantitation limit). EPA did not use the "J-values" in the loadings calculations. EPA treated all results that were less than the quantitation limit (*i.e.*, J-values and nondetects below the method detection limit) as half the sample-specific quantitation

[116] For data used for calculating pollutant loadings and effluent limits for the steam electric effluent guidelines, a sufficiently sensitive reporting limit (or a sufficiently sensitive analytical method) means that the analytical method is capable of and was used in a manner that most analytical results were above the level of quantitation. In instances where most analytical results were below the level of quantitation, sufficiently sensitive means that EPA is not aware of any other method approved in 40 CFR Part 136 that can produce substantially lower reporting limits for analyses of FGD wastewater.

[117] Only in EPA sampling activities were field blank and duplicate samples collected and analyzed. EPA's Clean Water Act (CWA) 308 sampling program did not include duplicate sample analysis. Therefore, only the field blank analysis was conducted on this data set. The plant provided self-monitoring data included no field blank or duplicate samples.

limit for all analytes. J-values, although the laboratory's best estimate of the pollutant concentration, are measurements made below the lowest point on the initial calibration curve (*i.e.*, quantitation limit) and thus have greater uncertainty associated with their quantitation therefore EPA handled them as half the quanititation limit rather than as zero or at the full quanititation limit.

- Field Blank Analysis: EPA compared the sample results from a specific sampling point to the field blank results for the same sampling point, on the specific day of sample collection. EPA used field blank results measured above the quantitation limit for this analysis (*i.e.*, did not use J-values associated with field blank samples). For the purpose of the loadings calculations, EPA made the following assumptions based on the results of this field blank analysis:
  - If the sample result was less than five times the field blank result, then the sample result was treated as a nondetect.
  - If the sample result was between five and 10 times the field blank result, then the sample result was flagged and handled as a qualified value.
  - If the sample result was greater than 10 times the field blank result, then the sample result was unchanged.
- Duplicate Sample Results: EPA averaged the results from each duplicate sample with the results of its original sample. EPA made the following assumptions when averaging the duplicate results:
  - If one value was quantified and the other value was not measured above the quantitation limit, then EPA used one-half the sample-specific quantitation limit for the non-quantified result in calculating the average.
  - If both values were not quantified above the sample-specific quantitation limit, then EPA used one-half the quantitation limit for both non-quantified results in calculating the average.
  - EPA used both qualified and unqualified data in the calculation.

Table 10-2. Data Sets Used in the FGD Loadings Calculation

Plant Name	Source of Data Set	Wastestreams Represented in Data Set
Progress Energy Carolinas' Roxboro Steam Electric Plant (Roxboro)	Monitoring data provided by plant	Settling impoundment effluent
Duke Energy's Miami Fort Station (Miami Fort)	EPA sampling	Chemical precipitation effluent and FGD purge [a]
	EPA CWA 308 sampling	Chemical precipitation effluent
	Monitoring data provided by plant	Chemical precipitation effluent
RRI Energy's Keystone Generating Station (Keystone)	EPA sampling	Chemical precipitation effluent and FGD purge [a]
	EPA CWA 308 sampling	Chemical precipitation effluent
	Monitoring data provided by plant	Chemical precipitation effluent
Allegheny Energy's Hatfield's Ferry Electric Plant (Hatfield's Ferry)	EPA sampling	Chemical precipitation effluent and FGD purge [a]

Table 10-2. Data Sets Used in the FGD Loadings Calculation

Plant Name	Source of Data Set	Wastestreams Represented in Data Set
	EPA CWA 308 sampling	Chemical precipitation effluent
	Monitoring data provided by plant	Chemical precipitation effluent
NRG Energy's Dickerson Generating Station (Dickerson)	EPA sampling	FGD purge [a]
We Energies' Pleasant Prairie Power Plant (Pleasant Prairie)	EPA sampling	Chemical precipitation effluent and FGD purge [a]
	EPA CWA 308 sampling	Chemical precipitation effluent
	Monitoring data provided by plant	Chemical precipitation effluent
Duke Energy Carolinas' Belews Creek Steam Station (Belews Creek)	EPA sampling	Biological treatment effluent and FGD purge [a]
	EPA CWA 308 sampling	Biological treatment effluent
	Monitoring data provided by plant	Biological treatment effluent and FGD purge [a]
Duke Energy Carolinas' Allen Steam Station (Allen)	EPA sampling	Biological treatment effluent and FGD purge [a]
	EPA CWA 308 sampling	Biological treatment effluent
	Monitoring data provided by plant	Biological treatment effluent and FGD purge [a]
Enel's Federico II Power Plant (Brindisi)	EPA sampling	Evaporation effluent

a – EPA used FGD purge data to estimate settling impoundment effluent concentrations. See Section 10.2.1.1 for details on the methodology used to estimate these concentrations.

Each of the following sections presents the characterization data set used to calculate mass and TWPE loadings for each option, starting with the baseline characterization.

10.2.1.1 Baseline FGD Wastewater Loading Characterization

As discussed in Section 9, EPA identified 88 plants[118] that operate wet FGD systems and discharge FGD wastewater. For the FGD dischargers, EPA calculated baseline loadings by assigning pollutant concentrations based on the type of treatment system currently in place at the plant. EPA assigned treatment in place for this wastewater to one of four classes of treatment: surface impoundment, chemical precipitation, biological treatment, and evaporation. As discussed in Section 9, EPA used Steam Electric Survey data to determine the baseline FGD

[118] EPA estimated compliance costs associated with control of FGD wastewater for 87 plants. One plant operates only oil-fired generating units and/or units with a generating capacity of 50 MW or less; therefore, plant is subject to BAT limitations that are equal to existing BPT requirements. As such, EPA assumed that this plant will not need to install the technology basis and, therefore, will not incur compliance costs. Additionally, EPA assumed that this plant will continue to discharge FGD wastewater at its current baseline level and will not achieve any pollutant removals for the technology options evaluated.

wastewater treatment in place. Based on Steam Electric Survey responses, EPA categorized 51 plants as operating a treatment system more advanced than a surface impoundment[119]:

- Forty-five plants operate a chemical precipitation system.
- Four plants operate a biological treatment system.
- Two plants operate an evaporation system.

EPA categorized all plants not operating one of these three types of treatment systems as operating impoundment systems in the baseline loadings calculations. While some of these plants may operate a system that is not an impoundment, EPA determined that these other systems are typically only solids removal systems that do not include hydroxide or sulfide precipitation (*e.g.*, clarifier with polymer addition). These types of system are effective at removing solids and metals in the particulate phase, but do not remove dissolved solids, similar to the operation of an impoundment.

As discussed in Section 7.1.1, surface impoundments use gravity to remove particulates from wastewater, reducing the amount of total suspended solids (TSS) and particulate forms of other pollutants in the wastewater. EPA obtained surface impoundment effluent data from a steam electric power plant that treats only FGD wastewater in the impoundment. In addition, EPA's sampling program collected and analyzed the untreated FGD wastewater of seven steam electric power plants operating wet FGD systems that use either chemical precipitation or chemical precipitation followed by biological treatment to treat the FGD wastewater (see Section 3.4 for a description of these sampling activities and plants). Based on analytical data for the untreated FGD wastewater at these sampled plants, EPA estimated the effluent concentration from a surface impoundment by assuming that a surface impoundment will remove most of the particulate phase metals, but will not remove dissolved metals from the wastewater.[120] EPA calculated proxy values using the untreated FGD wastewater data to represent impoundment effluent concentrations for each analyte using the data for each of these seven EPA sampled plants. EPA averaged the surface impoundment data along with the estimated impoundment effluent concentrations from the seven sampled plants for each analyte to generate an average effluent concentration data set for surface impoundments treating FGD wastewater based on the eight plants.

For pollutants not included in the surface impoundment effluent characterization data but in the effluent characterization data for the chemical precipitation technology option, EPA transferred the concentrations for these pollutants from the chemical precipitation effluent to the surface impoundment effluent (see Section 10.2.1.2). EPA determined that because ammonia, biological oxygen demand (BOD), chemical oxygen demand (COD), hexavalent chromium, cyanide, nitrate/nitrite, total Kjeldahl nitrogen, and total phosphorus are present in the chemical

[119] EPA's categorization of FGD treatment presented here takes into account expected plant operation changes resulting from the CCR rule (see Section 9 regarding EPA's methodology for incorporating these types of changes). EPA identified 41 plants currently operating a treatment system more advanced than a surface impoundment. An additional 10 plants are expected to upgrade FGD wastewater treatment systems as a result of the CCR rule.

[120] The methodology used to estimate settling impoundment effluent concentrations is presented in detail in the *Incremental Costs and Pollutant Removals for Final Effluent Limitation Guidelines and Standards for the Steam Electric Generating Point Source Category* report [U.S. EPA, 2015].

precipitation effluent, they are also present in the untreated FGD wastewater. Therefore, they would also be present in the surface impoundment effluent. This assumption results in zero pollutant removals for these pollutants for the chemical precipitation technology option. Table 10-3 presents the average characterization data used to calculate baseline loadings for plants currently treating FGD wastewater in a surface impoundment prior to discharge.

Approximately 60 percent of plants discharging FGD wastewater use a more advanced treatment system than surface impoundments. For those plants currently operating a chemical precipitation system or biological treatment system, EPA used the concentration data sets associated with the applicable post-compliance technology option to calculate baseline loadings. EPA also calculated a concentration data set for evaporation effluent to characterize loadings for plants currently operating these types of treatment systems. Section 10.2.1.2 discusses the characterization of chemical precipitation systems. Sections 10.2.1.3 and 10.2.1.4 discuss the characterization of chemical precipitation systems with biological treatment or with evaporation systems, respectively.

Table 10-3. Average Effluent Pollutant Concentrations for FGD Surface Impoundments

Analyte	Unit	Average Concentration
Classicals		
Ammonia	ug/L	6,850
Nitrate Nitrite as N	ug/L	96,000
Nitrogen, Kjeldahl	ug/L	32,900
Biochemical Oxygen Demand	ug/L	2,220
Chemical Oxygen Demand	ug/L	404,000
Chloride	ug/L	7,120,000
Sulfate	ug/L	1,240,000
Cyanide, Total	ug/L	949
Total Dissolved Solids	ug/L	32,500,000
Total Suspended Solids	ug/L	27,900
Phosphorus, Total	ug/L	319
Total Metals, Metalloids, and Other Nonmetals		
Aluminum	ug/L	2,080
Antimony	ug/L	12.9
Arsenic	ug/L	7.59
Barium	ug/L	303
Beryllium	ug/L	1.92
Boron	ug/L	243,000
Cadmium	ug/L	113
Calcium	ug/L	2,050,000
Chromium	ug/L	17.8
Hexavalent Chromium	ug/L	5.22

Table 10-3. Average Effluent Pollutant Concentrations for FGD Surface Impoundments

Analyte	Unit	Average Concentration
Cobalt	ug/L	183
Copper	ug/L	21.8
Iron	ug/L	1,510
Lead	ug/L	4.66
Magnesium	ug/L	3,370,000
Manganese	ug/L	93,400
Mercury	ug/L	7.78
Molybdenum	ug/L	125
Nickel	ug/L	878
Selenium	ug/L	1,170
Silver	ug/L	0.925
Sodium	ug/L	276,000
Thallium	ug/L	13.7
Tin	ug/L	100
Titanium	ug/L	27.1
Vanadium	ug/L	16.4
Zinc	ug/L	1,390

Source: [ERG, 2012a – 2012i; NCDENR, 2011].

Note: Concentrations are rounded to three significant figures.

10.2.1.2 Baseline and Post-Compliance Chemical Precipitation Pollutant Characterization

As part of the sampling activities described in Section 3, EPA identified and collected data from eight plants operating chemical precipitation systems, sometimes in conjunction with other technologies, such as biological treatment. The specific operating characteristics of the chemical precipitation treatment systems varied. EPA conducted an engineering review of the data and identified four systems operating consistently with the chemical precipitation technology basis. These four plants, Hatfield's Ferry, Miami Fort, Keystone, and Pleasant Prairie, operate chemical precipitation systems that include hydroxide and sulfide precipitation, as well as iron coprecipitation. These four plants burn a variety of coal types with two plants burning only bituminous coal, one plant burning only subbituminous coal, and the remaining plant using a combination of bituminous and subbituminous coals. EPA determined from the engineering review of the data for the remaining five plants, Allen, Belew's Creek, Dickerson, Brindisi, and A2A's Centrale di Monfalcone (Monfalcone), that these plants should not be considered in the evaluation of the chemical precipitation characteristics because they do not operate consistently with the technology basis.

The treatment systems at these four plants operating consistently with the chemical precipitation technology basis have similar operations; however, the plants have varying configurations and operating characteristics, such as thickeners, filter presses, sand filters, and retention time. Each of these systems was designed and is operated to remove suspended solids and dissolved metals from the FGD wastewater to achieve a similar level of pollutant discharge. The systems are sized to handle a specific flow rate of FGD wastewater, which means that the sizes of the tanks were designed to allow for the residence time required for settling and/or reactions to occur to achieve effluent concentrations meeting the plants' permit limits.

Chemical precipitation effluent characterization data came from multiple data sources, including EPA sampling, CWA 308 monitoring, and plant self-monitoring data. These data vary between daily, weekly, and monthly results and the number of results for each analyte is not consistent. Samples may have also been collected on the same day as EPA's sampling and CWA 308 monitoring activities (*i.e.*, duplicate samples may exist across multiple data sources). Therefore, EPA calculated the average effluent concentrations for chemical precipitation using the following approach to account for variability:

1. Treat all samples collected during any of the four EPA sampling dates as a duplicate result. Calculate daily averages for samples on these dates and then calculate a four-day average. EPA is treating the four-day average as an equivalent weekly result.
2. Calculate the average effluent concentration as an average of the four-day average and the remaining sample concentrations.

EPA analyzed the pollutant-specific treatment effectiveness of the chemical precipitation treatment technology. In this analysis, EPA reviewed pollutant concentrations at the influent to the chemical precipitation system (*i.e.*, FGD purge wastewater) using data from the four plants operating this technology basis, Hatfield's Ferry, Miami Fort, Keystone, and Pleasant Prairie. To ensure that the treatment effectiveness could be evaluated, EPA performed an analysis to identify pollutants present at treatable levels based on an evaluation of untreated FGD wastewater.[121] Where specific pollutants were identified at treatable levels, EPA calculated plant-specific percent removals across the chemical precipitation system and evaluated whether the pollutant was treated with the treatment technology. For those pollutants identified as treated, EPA used the pollutant-specific chemical precipitation effluent concentration for pollutant loadings calculations. For those pollutants not identified at treatable levels or not identified as treated, EPA used the surface impoundment effluent concentration (see Table 10-3). The *Incremental Costs and Pollutant Removals for Final Effluent Limitation Guidelines and Standards for the Steam Electric Generating Point Source Category* report [U.S. EPA, 2015] describes in more detail the methodology to develop the chemical precipitation effluent concentrations used for pollutant loadings.

Table 10-4 presents the average chemical precipitation effluent concentrations and the concentration basis, either surface impoundment or chemical precipitation effluent. EPA used these average concentrations to calculate the post-compliance loadings that plants that currently operate surface impoundments would discharge if they were to install the chemical precipitation technology. EPA also used the average concentrations presented in Table 10-4 to calculate the

[121] Because the influent to the chemical precipitation system is untreated FGD wastewater, the analysis to identify pollutants at treatable levels is identical to the pollutants of concern analysis described in Section 6, however; this analysis is only done for the four plants operating the chemical precipitation technology basis.

baseline loadings for any plant currently operating a chemical precipitation treatment system as FGD wastewater treatment.

As explained above, the values presented in Table 10-4 reflect four plants identified as operating consistently with the technology basis, and EPA has applied these values to all plants that operate chemical precipitation systems as their baseline concentrations. As discussed in Section 10.2.1.1, EPA classified 41 other plants as operating chemical precipitations systems. However, these 41 plants do not operate their chemical precipitation system in the same manner as the technology basis (or have all the components included in the technology basis) and would likely discharge greater pollutant concentrations than the systems reflecting the technology basis. Further, for these 41 plants, the baseline and post-compliance loadings are identical and EPA calculates no removals for these plants, even though these plants are being assessed compliance costs to upgrade the system to operate similarly to the technology basis. EPA does not have sufficient data to characterize the discharges from these 41 plants. The pollutant loadings from these plants would be somewhere between the chemical precipitation loadings and the impoundment effluent loadings, but EPA could not determine the appropriate concentrations to use to estimate loadings. Therefore, as a conservative estimate, EPA assumed the pollutant loadings were equivalent to the chemical precipitation effluent loadings.

Table 10-4. Average Effluent Pollutant Concentrations for Chemical Precipitation System

Analyte	Unit	Average Concentration	Concentration Basis
Classicals			
Ammonia	ug/L	6,850	Chemical Precipitation Effluent
Nitrate Nitrite as N	ug/L	96,000	Chemical Precipitation Effluent
Nitrogen, Kjeldahl	ug/L	32,900	Chemical Precipitation Effluent
Biochemical Oxygen Demand	ug/L	2,220	Chemical Precipitation Effluent
Chemical Oxygen Demand	ug/L	404,000	Chemical Precipitation Effluent
Chloride	ug/L	7,120,000	Surface Impoundment
Sulfate	ug/L	1,240,000	Surface Impoundment
Cyanide, Total	ug/L	949	Chemical Precipitation Effluent
Total Dissolved Solids	ug/L	24,100,000	Chemical Precipitation Effluent
Total Suspended Solids	ug/L	8,590	Chemical Precipitation Effluent
Phosphorus, Total	ug/L	319	Chemical Precipitation Effluent
Total Metals, Metalloids, and Other Nonmetals			
Aluminum	ug/L	120	Chemical Precipitation Effluent
Antimony	ug/L	4.25	Chemical Precipitation Effluent
Arsenic	ug/L	5.83	Chemical Precipitation Effluent
Barium	ug/L	140	Chemical Precipitation Effluent
Beryllium	ug/L	1.34	Chemical Precipitation Effluent
Boron	ug/L	225,000	Chemical Precipitation Effluent
Cadmium	ug/L	4.21	Chemical Precipitation Effluent
Calcium	ug/L	1,920,000	Chemical Precipitation Effluent

Table 10-4. Average Effluent Pollutant Concentrations for Chemical Precipitation System

Analyte	Unit	Average Concentration	Concentration Basis
Chromium	ug/L	6.45	Chemical Precipitation Effluent
Hexavalent Chromium	ug/L	5.22	Chemical Precipitation Effluent
Cobalt	ug/L	9.30	Chemical Precipitation Effluent
Copper	ug/L	3.78	Chemical Precipitation Effluent
Iron	ug/L	110	Chemical Precipitation Effluent
Lead	ug/L	3.39	Chemical Precipitation Effluent
Magnesium	ug/L	3,370,000	Surface Impoundment
Manganese	ug/L	12,500	Chemical Precipitation Effluent
Mercury	ug/L	0.139	Chemical Precipitation Effluent
Molybdenum	ug/L	125	Surface Impoundment
Nickel	ug/L	9.11	Chemical Precipitation Effluent
Selenium	ug/L	928	Chemical Precipitation Effluent
Silver	ug/L	0.925	Surface Impoundment
Sodium	ug/L	276,000	Surface Impoundment
Thallium	ug/L	9.81	Chemical Precipitation Effluent
Tin	ug/L	100	Surface Impoundment
Titanium	ug/L	9.30	Chemical Precipitation Effluent
Vanadium	ug/L	12.6	Chemical Precipitation Effluent
Zinc	ug/L	20.0	Chemical Precipitation Effluent

Source: [ERG, 2012c; ERG, 2012f; ERG, 2012g; ERG, 2012i].
Note: Concentrations are rounded to three significant figures.

10.2.1.3 Baseline and Post-Compliance Chemical Precipitation with Biological Treatment Characterization

EPA identified and collected data from two plants, Allen and Belews Creek, operating chemical precipitation systems in conjunction with biological treatment systems that represent the well-operated biological treatment systems that form the technology basis for the final rule. After conducting an engineering review of the data, EPA determined that both plants operate systems consistent with the chemical precipitation with biological treatment technology option. Both plants operate chemical precipitation systems followed by anoxic/anaerobic biological treatment systems specifically designed for selenium removal. EPA used the data from these plants to represent treatment performance of a chemical precipitation system with biological treatment system; however, these plants do not fully represent the technology option because neither plant currently uses sulfide precipitation within their chemical precipitation system. Therefore, these plants likely do not demonstrate mercury (and other metals) effluent concentrations as low as could be achieved by the chemical precipitation (with sulfide precipitation) followed by a biological treatment system that forms the basis for the final rule (see Section 7 for a complete description of the technology). EPA also collected data from a third plant, Dickerson, operating chemical precipitation followed by biological treatment. EPA did not include data from Dickerson because the biological treatment technology it operates is a sequencing batch reactor that is not designed to target selenium removal and is therefore not consistent with the technology basis for biological treatment.

EPA has multiple sets of data for these two plants including EPA sampling data, CWA 308 sampling data, and self-monitoring data to calculate pollutant loadings associated with this technology. These data vary between daily, weekly, and monthly results and the number of results for each analyte is not consistent. Samples may have also been collected on the same day as EPA's sampling and CWA 308 monitoring activities (*i.e.*, duplicate samples may exist across multiple data sources). Therefore, EPA calculated the average effluent concentrations for chemical precipitation and biological treatment using the following approach to account for variability:

1. Treat all samples collected during any of the four EPA sampling dates as a duplicate result. Calculate daily averages for samples on these dates and then calculate a four-day average. EPA is treating the four-day average as an equivalent weekly result.
2. Calculate the average effluent concentration as an average of the four-day average and the remaining sample concentrations.

EPA analyzed the pollutant-specific treatment effectiveness of the biological treatment technology. In this analysis, EPA reviewed pollutant concentrations at the influent to the biological treatment system (*i.e.*, chemical precipitation effluent) using data from the two plants operating this technology basis, Allen and Belews Creek. To ensure that the treatment effectiveness could be evaluated, EPA identified pollutants present at treatable levels based on an evaluation of untreated and partially treated FGD wastewater. Where specific pollutants were identified at treatable levels, EPA calculated plant-specific percent removals across the biological treatment system and evaluated whether the pollutant was treated with the treatment technology. For those pollutants identified as treated, EPA used the pollutant-specific biological treatment effluent concentration for pollutant loadings calculations. For those pollutants not identified at treatable levels, or not identified as treated, EPA used the chemical precipitation effluent concentration (see Table 10-4). The *Incremental Costs and Pollutant Removals for Final Effluent Limitation Guidelines and Standards for the Steam Electric Generating Point Source Category* report [U.S. EPA, 2015] describes in more detail the methodology used to develop the biological treatment effluent concentrations used for pollutant loadings.

Table 10-5 presents the average biological treatment effluent concentrations and the concentration basis, surface impoundment, chemical precipitation effluent, or biological treatment effluent. EPA used these average concentrations to calculate the post-compliance loadings that would be discharged by plants currently operating surface impoundments or chemical precipitation systems if they were to install all components of the biological technology option. EPA also used the average concentrations presented in Table 10-5 to calculate the baseline loadings for any plant currently operating chemical precipitation and a biological treatment system as FGD wastewater treatment.

The average concentration used to calculate baseline and post-compliance loadings for the chemical precipitation and biological treatment system technology basis, presented in Table 10-5, is based on two plants identified as operating consistently with the technology basis. As discussed in Section 10.2.1.1, EPA classified four plants as operating biological treatment systems. For each plant classified as a baseline biological treatment system, EPA calculated the baseline loadings using the average concentration presented in Table 10-5. One of these plants does not operate consistently with the technology basis and likely discharges greater pollutant concentrations than the system reflecting the technology basis.[122] Further, for this plant, the baseline and post-compliance loadings are identical and show no additional removals even though this plant is being assessed compliance costs to upgrade the system to achieve the technology basis.

Table 10-5. Average Effluent Pollutant Concentrations for Chemical Precipitation System with Biological Treatment

Analyte	Unit	Average Concentration	Concentration Basis
Classicals			
Ammonia	ug/L	6,850	Chemical Precipitation Effluent
Nitrate Nitrite as N	ug/L	647	Biological Treatment Effluent
Nitrogen, Kjeldahl	ug/L	32,900	Chemical Precipitation Effluent
Biochemical Oxygen Demand	ug/L	2,220	Chemical Precipitation Effluent
Chemical Oxygen Demand	ug/L	404,000	Chemical Precipitation Effluent
Chloride	ug/L	7,120,000	Surface Impoundment
Sulfate	ug/L	1,240,000	Surface Impoundment
Cyanide, Total	ug/L	949	Chemical Precipitation Effluent
Total Dissolved Solids	ug/L	24,100,000	Chemical Precipitation Effluent
Total Suspended Solids	ug/L	8,590	Chemical Precipitation Effluent
Phosphorus, Total	ug/L	319	Chemical Precipitation Effluent
Total Metals, Metalloids, and Other Nonmetals			
Aluminum	ug/L	120	Chemical Precipitation Effluent
Antimony	ug/L	4.25	Chemical Precipitation Effluent
Arsenic	ug/L	5.83	Chemical Precipitation Effluent
Barium	ug/L	140	Chemical Precipitation Effluent
Beryllium	ug/L	1.34	Chemical Precipitation Effluent
Boron	ug/L	225,000	Chemical Precipitation Effluent
Cadmium	ug/L	4.21	Chemical Precipitation Effluent
Calcium	ug/L	1,920,000	Chemical Precipitation Effluent
Chromium	ug/L	6.45	Chemical Precipitation Effluent
Hexavalent Chromium	ug/L	5.22	Chemical Precipitation Effluent
Cobalt	ug/L	9.30	Chemical Precipitation Effluent
Copper	ug/L	3.78	Chemical Precipitation Effluent
Iron	ug/L	110	Chemical Precipitation Effluent

[122] Of the four baseline biological treatment plants, only three are classified as operating consistently with the technology basis.

Table 10-5. Average Effluent Pollutant Concentrations for Chemical Precipitation System with Biological Treatment

Analyte	Unit	Average Concentration	Concentration Basis
Lead	ug/L	3.39	Chemical Precipitation Effluent
Magnesium	ug/L	3,370,000	Surface Impoundment
Manganese	ug/L	12,500	Chemical Precipitation Effluent
Mercury	ug/L	0.0507	Biological Treatment Effluent
Molybdenum	ug/L	125	Surface Impoundment
Nickel	ug/L	6.30	Biological Treatment Effluent
Selenium	ug/L	5.72	Biological Treatment Effluent
Silver	ug/L	0.925	Surface Impoundment
Sodium	ug/L	276,000	Surface Impoundment
Thallium	ug/L	9.81	Chemical Precipitation Effluent
Tin	ug/L	100	Surface Impoundment
Titanium	ug/L	9.30	Chemical Precipitation Effluent
Vanadium	ug/L	12.6	Chemical Precipitation Effluent
Zinc	ug/L	20.0	Chemical Precipitation Effluent

Source: [ERG, 2012a; ERG, 2012d; ERG, 2012i; Duke Energy, 2011a-2011b].
Note: Concentrations are rounded to three significant figures.

10.2.1.4 Baseline Chemical Precipitation with Evaporation Characterization

As described in Section 10.1, EPA did not evaluate post-compliance loadings associated with chemical precipitation followed by evaporation because EPA decided not to base the control of pollutants in FGD wastewater for existing sources on this technology due to the high cost. EPA evaluated average effluent concentrations for the discharge from chemical precipitation followed by evaporation in order to characterize the pollutants discharged from steam electric power plants currently operating this type of treatment for FGD wastewater. EPA conducted an engineering review of the data from the two plants operating evaporation systems for which EPA has analytical data, Iatan and Brindisi. EPA used data from the Brindisi plant to represent the technology option because it is the only sampled plant, in the United States or abroad, that matches the technology basis and operates a hydroxide-sulfide chemical precipitation system followed by softening, a brine concentrator, and a crystallization system. From the engineering review of the data, EPA determined that Iatan does not operate a chemical precipitation system followed by evaporation consistent with the technology basis. Iatan's pretreatment system does not include hydroxide or sulfide precipitation or iron coprecipitation, and it does not include softening prior to the evaporation system. Therefore, the Iatan plant does not represent the technology basis.

To calculate the average pollutant concentrations for the evaporation treatment system technology option, EPA first calculated an average concentration by analyte for each of the two evaporation wastestreams at the plant (*i.e.*, brine concentrator distillate and crystallizer condensate) using available sampling data (*i.e.*, 3-day EPA sampling data).[123] For this plant, EPA collected and analyzed only total concentrations; therefore, EPA did not have hexavalent chromium data to use in the analysis.

Using the average concentrations from the two streams (brine concentrator distillate and crystallizer condensate), EPA calculated an average concentration for each analyte. EPA transferred pollutant concentrations from the chemical precipitation effluent concentrations for pollutants that were not characterized in the evaporation data set, similar to what was done for surface impoundments as described in Section 10.2.1.1. EPA used chemical precipitation concentrations for biochemical oxygen demand, hexavalent chromium, and cyanide. Table 10-6 presents the average evaporation effluent concentrations by analyte. EPA used the average concentrations presented in Table 10-6 to calculate the baseline loadings for any plant currently operating a chemical precipitation and evaporation treatment system for FGD wastewater treatment.

Table 10-6. Average Effluent Pollutant Concentrations for Chemical Precipitation System with Evaporation

Analyte	Unit	Average Concentration
Classicals		
Ammonia	ug/L	24,300
Nitrate Nitrite as N	ug/L	100
Nitrogen, Kjeldahl	ug/L	23,500
Biological Oxygen Demand	ug/L	2,220
Chemical Oxygen Demand	ug/L	10,000
Chloride	ug/L	1,500
Sulfate	ug/L	2,500
Total Dissolved Solids	ug/L	10,800
Total Suspended Solids	ug/L	2,000
Phosphorus, Total	ug/L	25.0
Total Metals, Metalloids, and Other Nonmetals		
Aluminum	ug/L	100
Antimony	ug/L	1.00
Arsenic	ug/L	2.00
Barium	ug/L	10.0
Beryllium	ug/L	1.00
Boron	ug/L	3,750
Cadmium	ug/L	2.00

[123] EPA used both the brine concentrator distillate and crystallizer condensate streams to calculate the loadings because both wastestreams could be discharged. The vapor-compression evaporation system at Brindisi is operated as a zero-discharge system with no wastewater being discharged to surface water or POTW. However, the plant could choose to discharge both the brine concentrator and the crystallizer condensate streams, together or separately.

Table 10-6. Average Effluent Pollutant Concentrations for Chemical Precipitation System with Evaporation

Analyte	Unit	Average Concentration
Calcium	ug/L	200
Chromium	ug/L	4.00
Hexavalent Chromium	ug/L	5.22
Cobalt	ug/L	10.0
Copper	ug/L	2.00
Iron	ug/L	100
Lead	ug/L	1.00
Magnesium	ug/L	200
Manganese	ug/L	10.0
Mercury	ug/L	0.0103
Molybdenum	ug/L	20.0
Nickel	ug/L	2.00
Selenium	ug/L	2.00
Silver	ug/L	1.00
Sodium	ug/L	5,000
Thallium	ug/L	1.00
Tin	ug/L	100
Titanium	ug/L	10.0
Vanadium	ug/L	5.00
Zinc	ug/L	28.5

Source: [ERG, 2012h].

Note: Concentrations are rounded to three significant figures.

10.2.2 Ash Transport Water Characterization

EPA used data collected during the detailed study, industry-supplied data, and publicly available data sources, including data received during public comment, to characterize pollutant discharge concentrations for ash transport water. EPA also used data from the Steam Electric Survey to characterize discharge flows [ERG, 2015b]. Below is a list of data sources evaluated and accepted by EPA to characterize the discharges from ash impoundments:

- EPA ash impoundment sampling data from the detailed study for the Homer City plant [U.S. EPA, 2009].
- Electric Power Research Institute (EPRI) Power Plant Integrated Systems - Chemical Emissions Study (PISCES) Reports [EPRI, 1997-2001].
- *Mitigation of SCR-Ammonia Related Aqueous Effects in a Fly Ash Pond* [EPRI, 2006].

- Permit application data (Form 2-C), as provided by member companies of the Utility Water Act Group (UWAG) [UWAG, 2008].
- *Development Document for Final Effluent Limitations Guidelines, New Source Performance Standards, and Pretreatment Standards for the Steam Electric Point Source Category*, EPA 440-1-82-029, November 1982 (1982 TDD) [U.S. EPA, 1982].
- Public comments received from Hoosier Energy, including responses to EPA follow-up questions regarding the data submitted in comments [Hoosier, 2013; Hoosier 2014].
- Public comments and supplemental data received from the UWAG, including responses to EPA follow-up questions [UWAG, 2013; UWAG, 2014].

Section 3 provides details regarding each of the data sources used in the ash impoundment loadings. EPA performed a detailed review of each of these data sources and evaluated the information available for use. EPA reviewed all available effluent data and excluded data that were not usable in the development of effluent characterization data because these data did not meet the following criteria in addition to the general criteria listed in Section 10.2:

- Analytical data must represent individual sample results or plant-level average sample concentrations rather than average results representing multiple plants.
- Samples that were collected from impoundments that could not be categorized by type (i.e., bottom ash impoundment, fly ash impoundment, combined ash impoundment).
- Samples must be at least 75% by volume ash transport water.
- Samples must be representative of actual ash impoundment effluent (*e.g.*, simulated impoundment effluent).

See the "Development Memorandum for the Steam Electric Analytical Database for the Final Rule" [ERG, 2015d] for more details on the data quality criteria and data exclusions specific for ash transport water.

EPA used information available from each data source to characterize the impoundment/outfall as either a fly ash impoundment, bottom ash impoundment, or combined ash impoundment. For the purpose of this analysis, EPA used the following criteria to make those determinations:

- Fly ash impoundment: An impoundment/outfall that receives at least 75 percent by volume fly ash transport water and does not receive bottom ash transport water. The impoundment may also receive other types of wastewater (*e.g.*, low volume wastewaters, cooling water).
- Bottom ash impoundment: An impoundment/outfall that receives at least 75 percent by volume bottom ash transport water and does not receive fly ash transport water. The impoundment may also receive other types of wastewater (*e.g.*, low volume wastewaters, cooling water).

- Combined ash impoundment: An impoundment/outfall where the combination of fly ash and bottom ash transport water comprises at least 75 percent by volume of the total flow. The impoundment may also receive other types of wastewater (*e.g.*, low volume wastewaters, cooling water).

EPA used the concentration data obtained from these data sources to calculate the average pollutant concentration in fly ash transport water, bottom ash transport water, and combined ash transport water. EPA notes that because the data associated with these impoundments may include other wastestreams (*e.g.*, cooling water), the concentrations may be diluted and thus underestimate the pollutant loadings. EPA reviewed the data and made some substitutions to the data sets, as appropriate. EPA treated all results that were less than the quantitation limit (*i.e.*, J-values and nondetects below the method detection limit) as half the sample-specific quantitation limit for all analytes.[124] If EPA could not confirm whether the nondetect results were presented as less than the quantitation limit or the method detection limit (or some other value), EPA treated the nondetects as half of the value provided. For each data point, EPA first identified the type of impoundment system the data represents (*i.e.*, fly ash impoundment, bottom ash impoundment, combined ash impoundment). EPA then calculated an average pollutant concentration for each impoundment for which it had data. For example, if a plant had pollutant concentration data for its fly ash impoundment for more than 1 day, EPA averaged all these data for that specific pollutant and impoundment to get a single representative value of an average concentration of that pollutant in the effluent from the fly ash impoundment. EPA did not generate an average pollutant concentration for analytes where all results were less than the quantitation limit. EPA used the same methodology to calculate the average concentration of a pollutant in the effluents from bottom ash impoundments and combined ash impoundments. Some data sources provided only one data point; therefore, the average is the same as that data point.

After calculating an average concentration for each type of impoundment at the plant-specific level, EPA then calculated an industry-level average pollutant concentration for each type of impoundment for which EPA had data by averaging the plant-level average concentrations for each type of impoundment.[125] Table 10-7 presents the average pollutant concentration for all three types of ash impoundment. EPA used these average concentration data sets to calculate the baseline loadings for all plants identified as discharging fly ash or bottom ash transport water.

The technology basis in the final rule for controlling both fly ash and bottom ash is dry or closed-loop ash handling. As discussed in Section 7, these systems do not discharge ash transport water; therefore, the average effluent concentration associated with dry or closed-loop recycle ash handling is zero. Because no ash transport water will be discharged from generating units to which the ELGs apply, the corresponding post-compliance discharge loading is zero.

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[124] To simplify the discussion, in this Section 10.2.2 the term "nondetect" is used to refer to both values measured below the quantitation limit and those values measured below the detection limit.

[125] The methodology used to calculate the average concentrations for ash impoundment effluent is presented in the *Incremental Costs and Pollutant Removals for Final Effluent Limitation Guidelines and Standards for the Steam Electric Generating Point Source Category* report [U.S. EPA, 2015].

Table 10-7. Average Effluent Pollutant Concentration for Ash Impoundment Systems

Analyte	Unit	Average Fly Ash Concentration	Average Bottom Ash Concentration	Average Combined Ash Concentration
Classicals				
Nitrate-Nitrite (as N)	ug/L	2,360	6,070	2,550
Total Kjeldahl Nitrogen	ug/L	4,080	1,160	891
Biochemical Oxygen Demand	ug/L	NA	NA	4,670
Chemical Oxygen Demand	ug/L	NA	20,800	26,000
Chloride	ug/L	12,800	28,100	16,300
Sulfate	ug/L	409,000	347,000	209,000
Sulfite	ug/L	NA	4,750	905
Cyanide	ug/L	NA	NA	5.28
Total Dissolved Solids	ug/L	469,000	754,000	266,000
Total Suspended Solids	ug/L	10,400	19,700	15,300
Fluoride	ug/L	276	NA	650
Phosphorus, Total	ug/L	71.8	204	196
Total Metals, Metalloids, and Other Nonmetals				
Aluminum	ug/L	2,230	1,240	1,200
Antimony	ug/L	NA	28.2	24.6
Arsenic	ug/L	36.4	17.4	50.3
Barium	ug/L	121	110	188
Beryllium	ug/L	3.42	NA	3.86
Boron	ug/L	6,630	541	1,960
Bromide	ug/L	NA	620	NA
Cadmium	ug/L	7.63	2.19	1.42
Calcium	ug/L	99,300	68,800	74,600
Chromium	ug/L	27.4	5.59	21.6
Hexavalent Chromium	ug/L	NA	NA	0.671
Cobalt	ug/L	5.67	14.5	6.00
Copper	ug/L	68.8	13.9	21.9
Iron	ug/L	855	1,420	601
Lead	ug/L	13.7	12.1	7.52
Magnesium	ug/L	13,600	34,500	15,300
Manganese	ug/L	144	1,440	67.5
Mercury	ug/L	0.828	0.634	1.18
Molybdenum	ug/L	483	29.7	142
Nickel	ug/L	30.5	16.5	19.1
Potassium	ug/L	8,460	2,960	12,900

Table 10-7. Average Effluent Pollutant Concentration for Ash Impoundment Systems

Analyte	Unit	Average Fly Ash Concentration	Average Bottom Ash Concentration	Average Combined Ash Concentration
Selenium	ug/L	15.4	11.8	28.0
Silica	ug/L	8,570	6,300	5,930
Silver	ug/L	NA	NA	4.33
Sodium	ug/L	34,000	53,000	12,400
Strontium	ug/L	429	258	NA
Thallium	ug/L	10.3	89.4	31.0
Titanium	ug/L	4.83	40.9	22.8
Vanadium	ug/L	NA	NA	56.4
Zinc	ug/L	226	31.0	72.3

Source: [U.S. EPA, 2009; U.S. EPA, 1982; EPRI, 1997-2001; EPRI, 2006; UWAG, 2008; Hoosier, 2013; Hoosier, 2014; UWAG, 2013; UWAG, 2014].

Note: Concentrations are rounded to three significant figures.

NA – Not applicable.

10.2.3 Baseline and Post-Compliance Combustion Residual Leachate Characterization

As described in Section 6, EPA determined that plants operating impoundments containing combustion residuals will recycle the leachate back to the impoundment from which it was collected rather than install the technology basis for the discharge requirements. EPA does not expect this recycled impoundment leachate to alter the discharge loadings of the impoundment. The pollutants contained in the impoundment leachate were previously in the system; by recycling the leachate back into the same impoundment, no additional pollutants are added to the system (*i.e.*, the surface impoundment).. The mass loadings that would have been discharged as combustion residual leachate are transferred back to the impoundment and that mass loading is then discharged from the ash impoundment. Therefore, EPA finds that baseline and post-compliance pollutant loadings will be the same for combustion residual impoundment leachate and only calculated baseline loadings for impoundment leachate.[126]

As described in Section 8, EPA evaluated chemical precipitation as a technology option for treating combustion residual landfill leachate. EPA used data collected through the Steam Electric Survey to calculate average effluent concentrations for untreated combustion residual leachate to characterize the combined discharge of impoundment leachate and landfill leachate.

EPA's Steam Electric Survey required certain plants to collect and analyze samples of leachate and report the results of these analyses. EPA requested these plants to sample any

[126] As explained in Section VIII of the final preamble, combustion residual leachate discharges contributes approximately three percent of the toxic weighted pounds discharged collectively by all steam electric power plants. While EPA did not include pollutant reductions from combustion residual leachate from impoundments in its estimates of pollutant removals associated with chemical precipitation, this would not have changed its conclusion to identify surface impoundments as BAT for combustion residual leachate.

untreated impoundment and landfill leachate collected from an on-site management unit (*i.e.*, impoundment or landfill) containing combustion residuals. EPA used all data provided by the plants in the Steam Electric Survey, except for the following:

- For values reported as less than the quantitation limit, EPA assumed the concentration was equal to one-half the quantitation limit provided.
- If the plant did not provide a quantitation limit, EPA assumed the concentration was equal to the method detection limit.

EPA compiled all untreated combustion residual leachate sampling data reported in the Steam Electric Survey from 26 landfills and 15 impoundments. To determine the industry average concentrations for a pollutant, EPA first averaged all concentration data provided for each individual management unit providing sampling data to calculate a management-unit-specific average concentration. EPA then averaged the management-unit-specific average concentrations at each plant to calculate a plant-level average pollutant leachate concentration. EPA then used the average plant-level combustion residual leachate to calculate the average concentrations across all plants. Table 6-9 presents the average concentrations for untreated combustion residual leachate. EPA used these average concentrations to calculate baseline loadings for all plants discharging combustion residual impoundment and/or landfill leachate.

As explained in Section 7.4, based on a review of the Steam Electric Survey data, EPA did not identify any plants currently operating a chemical precipitation system to treat landfill leachate. Therefore, EPA transferred the limitations and standards from the FGD chemical precipitation system. Because EPA does not have analytical data that represent the treatment of landfill leachate by chemical precipitation, EPA also transferred the FGD chemical precipitation effluent concentrations, identified in Section 10.2.1.2, to the landfill leachate for the purposes of calculating post-compliance loadings. In cases where the average concentration of the untreated combustion residual leachate is less than the FGD treated concentration for the technology option, EPA assumed that the treated concentration was equal to the influent (*i.e.*, untreated combustion residual leachate) average concentration. In this case, EPA did not calculate additional removals of these particular pollutants by the wastewater treatment system. Table 10-8 presents the average effluent concentration for chemical precipitation treatment of combustion residual leachate.

Table 10-8. Average Effluent Pollutant Concentrations for Chemical Precipitation System for the Treatment of Combustion Residual Leachate

Analyte	Unit	Average Concentration
Classicals		
Chloride	ug/L	413,000
Sulfate	ug/L	1,240,000
Total Dissolved Solids	ug/L	3,500,000
Total Suspended Solids	ug/L	8,590
Total Metals, Metalloids, and Other Nonmetals		
Aluminum	ug/L	120

Table 10-8. Average Effluent Pollutant Concentrations for Chemical Precipitation System for the Treatment of Combustion Residual Leachate

Analyte	Unit	Average Concentration
Antimony	ug/L	3.75
Arsenic	ug/L	5.83
Barium	ug/L	53.2
Beryllium	ug/L	1.33
Boron	ug/L	22,400
Cadmium	ug/L	4.21
Calcium	ug/L	408,000
Chromium	ug/L	6.45
Cobalt	ug/L	9.30
Copper	ug/L	3.78
Iron	ug/L	110
Lead	ug/L	2.37
Magnesium	ug/L	118,000
Manganese	ug/L	2,720
Mercury	ug/L	0.139
Molybdenum	ug/L	125
Nickel	ug/L	9.11
Selenium	ug/L	111
Silver	ug/L	0.925
Sodium	ug/L	276,000
Thallium	ug/L	1.16
Tin	ug/L	49.3
Titanium	ug/L	9.30
Vanadium	ug/L	12.6
Zinc	ug/L	20.0

Note: Concentrations are rounded to three significant figures.

EPA identified one plant currently operating a biological treatment system to treat landfill leachate (combined with FGD wastewater) and one plant building a biological treatment system to treat its combustion residual landfill leachate. EPA does not have analytical data that represent landfill leachate treated with biological treatment; therefore, EPA transferred the effluent concentrations from the FGD biological treatment, identified in Section 10.2.1.3, to calculate baseline loadings for these two plants. In cases where the average concentration of the untreated combustion residual leachate is less than the biological treatment FGD effluent concentration, EPA assumed that the treated concentration was equal to the untreated combustion residual leachate average concentration so as not to associate excess load with these plants. Although these two plants do not operate consistently with the technology basis for biological treatment and likely discharge greater pollutant concentrations than the system reflecting the technology basis, EPA calculated identical baseline and post-compliance loadings for these plants and show no removals. Table 10-8 presents the average effluent concentration for biological treatment of combustion residual leachate.

Table 10-9. Average Effluent Pollutant Concentrations for Biological Treatment of Combustion Residual Leachate

Analyte	Unit	Average Concentration
Classicals		
Chloride	ug/L	413,000
Sulfate	ug/L	1,240,000
Total Dissolved Solids	ug/L	3,500,000
Total Suspended Solids	ug/L	8,590
Total Metals, Metalloids, and Other Nonmetals		
Aluminum	ug/L	120
Antimony	ug/L	3.75
Arsenic	ug/L	5.83
Barium	ug/L	53.2
Beryllium	ug/L	1.33
Boron	ug/L	22,400
Cadmium	ug/L	4.21
Calcium	ug/L	408,000
Chromium	ug/L	6.45
Cobalt	ug/L	9.30
Copper	ug/L	3.78
Iron	ug/L	110
Lead	ug/L	2.37
Magnesium	ug/L	118,000
Manganese	ug/L	2,720
Mercury	ug/L	0.0507
Molybdenum	ug/L	125
Nickel	ug/L	6.30
Selenium	ug/L	5.72
Silver	ug/L	0.925
Sodium	ug/L	276,000
Thallium	ug/L	1.16
Tin	ug/L	49.3
Titanium	ug/L	9.30
Vanadium	ug/L	12.6
Zinc	ug/L	20.0

Note: Concentrations are rounded to three significant figures.

10.3 WASTEWATER FLOW RATES FOR BASELINE AND POST-COMPLIANCE POLLUTANT LOADINGS

As discussed in Section 10.1, EPA used plant-specific wastewater flow rates in the loadings calculations. EPA used information from the Steam Electric Survey, industry-submitted data, and publicly available information on planned retirements or operational changes to determine which plants discharge each specific wastestream of concern and the amount of wastewater each plant reported discharging. EPA calculated pollutant loadings several different ways to evaluate the effect of the ELG on the steam electric power generating industry. EPA considered other rulemakings affecting the steam electric industry in its analysis. EPA evaluated compliance costs and pollutant loadings taking into account the CCR rule, the CCR rule and the CPP rule, and without CCR and CPP. In general, values reported and discussed in this section refer to the pollutant loadings analysis with CCR and the loadings with CCR and CPP, unless otherwise noted. This section provides more detail on EPA's methodology for calculating the specific wastewater flow rates used to calculate pollutant loadings with CCR. EPA also adjusted its baseline to account for the CPP. Because only the proposed version of the CPP was available at the time EPA evaluated pollutant loadings, the Agency estimated loadings that account for expected changes from the CPP rather than the final CPP. Section 9.4.1 describes how EPA adjusted the population for both compliance costs and loadings to account for CPP.

10.3.1 FGD Wastewater Flow Rates for Pollutant Loadings

As described in Section 9, EPA used system-level FGD wastewater flow rates to calculate compliance costs. EPA used the same FGD wastewater flow rates in both the FGD wastewater technology cost modules and the FGD wastewater loadings to ensure consistency between the two estimates. As described in Section 9.4.1 the FGD wastewater flows EPA used to estimate pollutant loadings were based on data from the Steam Electric Survey and other industry provided data and adjusted for the CCR rule. See Section 4.3 of EPA's *Incremental Costs and Pollutant Removals for Final Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category* report for a detailed description of EPA's methodology for incorporating the CCR final rulemaking into the pollutant loadings flow rates [U.S. EPA, 2015].

10.3.2 Ash Transport Water Flow Rates for Pollutant Loadings

EPA calculated ash impoundment discharge loadings based on the amount of transport water discharged. EPA used information from the Steam Electric Survey and industry-submitted data to identify the population of plants that have steam electric generating units that generate fly ash, bottom ash, or combined ash transport water, send the transport water to a surface impoundment system(s), and discharge the transport water to surface waters or POTWs.[127] The ash transport water flows EPA used to estimate pollutant loadings were based on data from the Steam Electric Survey and other industry provided data and adjusted for the CCR rule. See Section 4.3 of EPA's *Incremental Costs and Pollutant Removals for Final Effluent Limitation*

[127] As defined in the Steam Electric Survey, impoundments refer to a system of one or more surface impoundments.

Guidelines and Standards for the Steam Electric Power Generating Point Source Category report for a detailed description of EPA's methodology for incorporating the CCR final rulemaking into the pollutant loadings flow rates [U.S. EPA, 2015].

EPA identified 144 plants that discharge ash transport water to a surface water or POTW. For each plant included in its analysis, EPA calculated a normalized, generating-unit-level fly ash transport water, bottom ash transport water, or combined ash transport water discharge flow rate. To calculate a generating-unit-level flow, EPA calculated a normalized plant-level flow and then applied a unit flow fraction.

To calculate the plant-level normalized flow, EPA used the following hierarchy to determine the ash transport water flow rates[128]:

- Influent ash transport water flow rates to the impoundments reported in the pond/impoundment systems section (Part D) of the Steam Electric Survey, including process flow diagrams.
- Percent contributions of ash transport water to a plant outfall, multiplied by the total outfall flow rate reported in the general power plant operations section (Part A) of the Steam Electric Survey.
- Process flow or water balance diagram (Part A).
- Generating-unit-level sluice flow rates (Part C).

Because most generating units, and corresponding ash handling systems, do not operate 365 days per year, EPA normalized the ash impoundment discharge flow rates. To do this, EPA calculated the amount of ash transport water transferred to each ash impoundment per year by multiplying the flow rate by the number of days the ash transport water is generated or transferred to the impoundment, depending on which source is being used. EPA divided this yearly ash transport water flow by 365 days per year to calculate a flow rate in gallons per day (gpd) for use in loadings calculations.

To calculate a generating-unit-level flow fraction, EPA calculated a normalized flow for each generating unit based on sluice flow rates for fly ash and bottom ash reported in Part C of the Steam Electric Survey. If the sluice flow data were not reported or incomplete, EPA used the amount of coal burned from responses to Part A of the Steam Electric Survey to estimate the total fly ash, bottom ash, or combined ash tonnage associated with a generating unit. After calculating all generating-unit-level data (either flow rate or tonnage), EPA summed the values to the plant level and calculated a generating-unit-level fraction by dividing the individual generating unit data by the plant total.

[128] The *Incremental Costs and Pollutant Removals for Final Effluent Limitation Guidelines and Standards for the Steam Electric Generating Point Source Category* report provides more detail regarding this hierarchy and EPA's methodology for generating impoundment-specific ash impoundment discharge flow rates [U.S. EPA, 2015].

Using the plant-level normalized ash flow rates and the calculated unit flow fraction, EPA calculated generating-unit-level ash impoundment discharge flow rates for each of the three possible types of ash transport waters (*i.e.*, fly, bottom, and combined).

EPA also reviewed data in the Steam Electric Survey and industry-submitted data, including public comments, to identify any additional updates to account for recycle and potential double counting. EPA adjusted bottom ash transport water flows in the ash flow input table for plants that recycle any of their bottom ash transport water. Where EPA received additional plant-specific information in public comments, EPA evaluated the information and updated the plant flows appropriately.

The ash transport water flow rates used for the loadings analysis are not the same data used to estimate compliance costs for plants to eliminate fly ash or bottom ash transport water. Based on information received from vendors, it is appropriate to estimate the necessary size of the ash handling technology options and corresponding compliance costs based on the amount of fly ash generated by specific generating units or the capacity of the unit. However, baseline and post-compliance loadings are based on the flow rate of ash transport water.

10.3.3 Combustion Residual Leachate Flow Rates for Pollutant Loadings

As described in Section 9, EPA used plant-level combustion residual landfill leachate flow rates to calculate compliance costs. EPA used the same combustion residual landfill leachate flow rates in the leachate technology cost modules and the landfill leachate loadings to ensure consistency between the two estimates. As described in Section 9, EPA did not estimate compliance costs for combustion residual impoundment leachate because it determined that plants would transfer any impoundment leachate back to the impoundment from which it was collected instead of installing a treatment system to meet the limitations. Therefore, EPA calculated only baseline loadings for combustion residual leachate from impoundments but it did not estimate post-compliance loadings associated with treating leachate from impoundments.

For each impoundment identified as collecting and discharging combustion residual leachate, EPA identified the combustion residual impoundment leachate volume discharged each year in gallons per day. For those plants that did not report a combustion residual impoundment leachate volume in the Steam Electric Survey, EPA estimated a flow rate using data from other plants that reported a combustion residual impoundment leachate volume in the Steam Electric Survey. EPA first determined a median combustion residual impoundment leachate discharge rate per acre of impoundment collecting leachate, based on the impoundment-specific responses to Part D of the Steam Electric Survey. EPA then multiplied the median value by a plant's reported impoundment surface area for those individual impoundments that collect combustion residual leachate to estimate a flow rate. For plants that did not provide impoundment-specific information, EPA determined a median leachate discharge rate per acre of impoundment containing combustion residuals, based on plant responses to Part C of the Steam Electric Survey. EPA then multiplied this median value by a plant's reported combustion residual impoundment acreage collecting leachate to estimate a flow rate. Finally, for those plants for which it could not estimate a value using the other three approaches, EPA estimated the combustion residual impoundment leachate volume using the median combustion residual impoundment leachate volume for all plants reporting a volume.

See Section 4.1.3.2 of EPA's *Incremental Costs and Pollutant Removals for Final Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category* report for more details on the combustion residual impoundment leachate flow rate estimation methodology [U.S. EPA, 2015].

While EPA adjusted the flow rates for FGD wastewater and ash transport water to account for the CCR rule, EPA did not make any such adjustments to the combustion residual landfill or impoundment leachate flow rates because none are expected.

10.4 BASELINE AND POST-COMPLIANCE POLLUTANT LOADINGS AND TWPE RESULTS

As discussed in Section 10.1, as applicable, EPA multiplied the average pollutant concentrations for each wastestream presented in Section 10.2 with the plant-specific wastewater flow rates presented in Section 10.3 to calculate the amount of pollutant discharged to surface waters for each plant and wastestream. For those plants discharging to a POTW, EPA adjusted the loadings to account for additional removals that would take place at the POTW. After calculating these loadings for each plant and wastestream, EPA then calculated the TWPE associated with the pollutant discharges for the baseline and post-compliance pollutant loadings for each plant associated with each technology option. Using the plant-level loadings by wastestream, EPA then calculated the baseline and post-compliance loading at the industry level for each wastestream and regulatory option. The following section discusses the specific loadings and TWPE calculations for each wastestream, several of the technology options considered, and each of the main regulatory options evaluated by EPA. The section also presents the industry-level loadings for each wastestream and regulatory option.

10.4.1 FGD Wastewater Loadings and TWPE

EPA calculated plant-specific loadings for several technology options considered for control of FGD wastewater by multiplying the plant-specific flow rate by the concentrations for each technology. For baseline loadings, EPA multiplied the plant-specific FGD wastewater discharge flow rate with the average pollutant concentrations that represent the current level of treatment at the plant (*i.e.*, surface impoundment, chemical precipitation, biological treatment, or evaporation).

For the post-compliance loadings associated with the chemical precipitation technology option, EPA assumed that the discharge loadings calculated for plants currently treating their FGD wastewater with a chemical precipitation system, a biological treatment system, or an evaporation system remain unchanged from baseline. EPA assumed plants with a baseline surface impoundment would install a chemical precipitation treatment system to meet the effluent requirements associated with this option. EPA calculated post-compliance loadings for these plants by multiplying the average concentration data set associated with chemical precipitation systems, presented in Table 10-4, and the plant-specific FGD wastewater flow rates. As described in Section 10.2.1.2, for each plant classified as a baseline chemical precipitation system, EPA used the same chemical precipitation effluent concentrations to calculate the baseline and post-compliance loadings, even if the system is not equivalent to the technology basis. This underestimates the pollutant removals being achieved by the treatment system because EPA calculates no removals for these plants, even though some of these plants are being assessed compliance costs to upgrade the system to operate similarly to the technology basis.

For the post-compliance pollutant loadings associated with the chemical precipitation treatment system followed by biological treatment technology option, EPA assumed the post-compliance loadings calculated for plants currently treating their FGD wastewater with a biological treatment system or an evaporation system remain unchanged from baseline. EPA assumed plants with a surface impoundment would install a chemical precipitation system with biological treatment and plants with a chemical precipitation system (but no biological treatment for selenium removal) would install a biological treatment system to meet the effluent requirements associated with this technology option.

EPA identified two plants transferring FGD wastewater to a POTW. For these two plants, EPA assumed that the plant would continue to transfer the wastewater to a POTW and, therefore, adjusted the baseline and post-compliance loadings to account for pollutant removals associated with POTW treatment.

Table 10-10 presents the FGD wastewater loadings at an industry level for baseline and each post-compliance technology option. These loadings are based on the oil-fired generating units and those generating units with a generating capacity of 50 megawatts (MW) or less not installing the technology basis because they are not facing any more stringent requirements than already existed under the previously established BPT regulations. The loadings include only those pollutants identified as POCs and also exclude the pollutant parameters BOD, COD, total dissolved solids (TDS), and TSS to avoid double counting the loadings for other specific pollutants. The table includes the number of plants identified as discharging FGD wastewater, the total industry discharge flow rate associated with each technology option, and the total industry loading in pounds per year and TWPE per year. Table 10-11 adjusted the results in Table 10-10, accounting for the expected closures related to the implementation of the CPP (referred to hereafter as "Accounting for CPP"). Table 10-12 presents the pollutant removals, in both pounds per year and TWPE per year, for the various technology options. EPA calculated the pollutant removals by subtracting the post-compliance loadings from the baseline loadings. Table 10-13 adjusted the results in Table 10-12, accounting for the CPP. The loadings for all generating units installing the technology basis, including the oil-fired generating units and small generating units (*i.e.*, 50 MW or less generating capacity), are presented in EPA's *Incremental Costs and Pollutant Removals for Final Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category* report [U.S. EPA, 2015].

Table 10-10. Industry-Level FGD Wastewater Loadings Excluding BOD, COD, TDS, and TSS and Based on Oil-Fired Units and Units 50 MW or Less Not Installing Technology Basis

Technology Option	Number of Plants	Total Industry Discharge Flow (million gallons per day (MGD))	Total Industry Loading	
			Pounds/Year	TWPE/Year
Baseline	88 [a]	41.7	1,660,000,000	1,880,000
Chemical Precipitation	88 [a]	38.4	1,620,000,000	1,070,000
Chemical Precipitation with Biological Treatment	88 [a]	38.4	1,610,000,000	925,000

Note: Excludes loadings for pollutants not identified as POCs and for BOD, COD, TDS and TSS.

Note: Loadings are rounded to three significant figures.

a – One plant operates only oil-fired generating units and/or generating units with a generating capacity of 50 MW or less; therefore, this plant is not facing any more stringent requirements than exist under the previously established BPT regulations. As such, EPA assumed that this plant will not install the technology basis and, therefore, will not incur any compliance costs. Additionally, EPA assumed it will continue to discharge FGD wastewater at its current baseline level and will not achieve any pollutant removals for the technology options evaluated.

Table 10-11. Industry-Level FGD Wastewater Loadings Excluding BOD, COD, TDS, and TSS and Based on Oil-Fired Units and Units 50 MW or Less Not Installing Technology Basis, Accounting for CPP

Technology Option	Number of Plants	Total Industry Discharge Flow (MGD)	Total Industry Loading	
			Pounds/Year	TWPE/Year
Baseline	69	32.4	1,290,000,000	1,550,000
Chemical Precipitation	69	30.4	1,260,000,000	842,000
Chemical Precipitation with Biological Treatment	69	30.4	1,250,000,000	723,000

Note: Excludes loadings for pollutants not identified as POCs and for BOD, COD, TDS and TSS.

Note: Loadings are rounded to three significant figures.

Table 10-12. FGD Wastewater Pollutant Removals Excluding BOD, COD, TDS, and TSS and Based on Oil-Fired Units and Units 50 MW or Less Not Installing Technology Basis

Technology Option	Total Industry Pollutant Removals	
	Pounds/Year	TWPE/Year
Reduction (Baseline –>Chemical Precipitation)	36,800,000	804,000
Reduction (Baseline –>Chemical Precipitation with Biological Treatment)	47,200,000	952,000

Note: Excludes loadings for pollutants not identified as POCs and for BOD, COD, TDS and TSS.

Note: Removals are rounded to three significant figures. The removals may not equal the subtraction of the technology option from the baseline using the values in Table 10-10 due to rounding.

Table 10-13. FGD Wastewater Pollutant Removals Excluding BOD, COD, TDS, and TSS and Based on Oil-Fired Units and Units 50 MW or Less Not Installing Technology Basis, Accounting for CPP

Technology Option	Total Industry Pollutant Removals	
	Pounds/Year	TWPE/Year
Reduction (Baseline –>Chemical Precipitation)	26,700,000	706,000
Reduction (Baseline –>Chemical Precipitation with Biological Treatment)	35,200,000	826,000

Note: Excludes loadings for pollutants not identified as POCs and for BOD, COD, TDS and TSS.

Note: Removals are rounded to three significant figures. The removals may not equal the subtraction of the technology option from the baseline using the values in Table 10-11 due to rounding.

10.4.2 Ash Transport Water Loadings and TWPE

EPA calculated plant-specific loadings for the baseline discharges and key technology options considered for control of ash transport water. EPA estimated pollutant loadings and removals for pollutants that were identified as POCs for fly ash transport water, bottom ash transport water, or that were identified as constituents of combined ash impoundments.[129] For baseline loadings, EPA multiplied the plant-specific ash transport water discharge flow rate for each type of ash transport water (*i.e.*, fly ash, bottom ash, or combined ash transport water) by the appropriate average concentration data set for the type of discharge. For example, for each fly ash impoundment, EPA multiplied the normalized discharge flow rate described in Section 10.3.2 for the plant's fly ash impoundment by the average concentration data set associated with fly ash impoundments presented in Section 10.2.2. EPA identified four plants transferring bottom ash transport water to a POTW. For these four plants, EPA adjusted the baseline loadings to account for pollutant removals associated with POTW treatment, as described in Section 10.1.

Because EPA considered regulatory options that would establish different effluent requirements for fly ash and bottom ash, EPA analyzed the pollutant loadings and removals for these two wastestreams separately; therefore, EPA separated the loadings for combined ash impoundments into fly ash transport water loadings and bottom ash transport water loadings. To do this, EPA used data from the following three EPRI PISCES reports to estimate the breakout of the loadings among fly ash and bottom ash contributions specific to each pollutant:

- *PISCES Water Characterization Field Study: Sites A and B Report* [EPRI, 1997-2001].
- *PISCES Water Characterization Field Study: Site C Report* [EPRI, 1997-2001].
- *PISCES Water Characterization Field Study: Site D Report* [EPRI, 1997-2001].

The PISCES reports include information from several plants operating impoundments receiving either fly ash transport water and/or bottom ash transport water. The reports include a table presenting loadings associated with each stream entering the impoundment for several

[129] EPA calculated combined ash pollutant loadings for fly ash transport water and bottom ash transport water POCs, as well as biochemical oxygen demand (BOD), cyanide, hexavalent chromium (chromium VI), and silver which were identified as constituents of combined fly ash and bottom ash impoundments.

metal pollutants. EPA used the fly ash and bottom ash loadings presented in the reports to calculate a site-specific percent loading for fly ash and bottom ash for each pollutant. EPA then calculated an average percent loading for fly ash and bottom ash using data from all available pollutants. EPA determined that, on average, pollutant contributions from fly ash account for 86 percent of combined ash loadings, with bottom ash contributing only 14 percent. Therefore, EPA assumed fly ash and bottom ash account for 86 and 14 percent, respectively, of all combined ash loadings for those pollutants for which an analyte-specific value could not be calculated using the EPRI data. EPA then used these percentages to break out the combined ash loadings into associated fly ash and bottom ash loadings, and calculated total fly ash and bottom ash transport water baseline loadings for each plant [ERG, 2015a].

EPA assumes that all plants currently discharging ash transport water, and subject to the ELGs, will install dry handling systems for fly ash and will operate wet-sluicing bottom ash handling systems as a closed-loop system (*i.e.*, zero discharge) or will convert to dry bottom ash handling, resulting in post-compliance loadings of zero for fly ash and bottom ash transport water pollutants for those plants subject to the requirements.

Table 10-14 presents the baseline ash transport water loadings on an industry level. The table includes the number of plants discharging each type of ash transport water, the total industry discharge flow rate, and the total baseline industry loadings in pounds per year and TWPE per year associated with each type of impoundment. The industry-level baseline loadings presented in Table 10-14 include only those pollutants identified as POCs and excludes BOD, COD, TDS, and TSS (to avoid double counting the loadings for other specific pollutants). See Section 6 for a more detailed discussion of the POC evaluation for fly ash and bottom ash transport water. Table 10-15 adjusts the results presented in Table 10-14, accounting for the CPP.

Table 10-14. Industry-Level Baseline Ash Impoundment Loadings by Type of Impoundment Excluding BOD, COD, TDS, and TSS

Type of Ash Impoundment	Number of Plants	Total Baseline Industry Discharge Flow (MGD)	Total Industry Baseline Loading	
			Pounds/Year	TWPE/Year
Fly Ash				
Fly Ash Pond	9	25	46,700,000	69,000
Combined Ash Pond [a]	N/C [b]	N/C [b]	68,100,000	156,000

Table 10-14. Industry-Level Baseline Ash Impoundment Loadings by Type of Impoundment Excluding BOD, COD, TDS, and TSS

Type of Ash Impoundment	Number of Plants	Total Baseline Industry Discharge Flow (MGD)	Total Industry Baseline Loading	
			Pounds/Year	TWPE/Year
Bottom Ash				
Bottom Ash Pond	115	200	340,000,000	481,000
Combined Ash Pond [a]	N/C [b]	N/C [b]	14,800,000	27,400
TOTAL	**144**	**298-315[c]**	**469,000,000**	**733,000**

N/C – Not calculated.

Note: Excludes loadings for pollutants not identified as POCs and for BOD, COD, TDS, and TSS.

Note: Loadings are rounded to three significant figures.

a – The combined ash pond loadings were calculated based on the data used in the loadings calculation, but then the total combined ash pond loadings were split between fly ash and bottom ash based on the EPRI data, as described in this section.

b – After incorporating updates based on the CCR rule, EPA identified a total of 25 plants discharging combined ash transport water from combined ash ponds. EPA reduced the baseline loadings (pounds and TWPE) for five of these plants due to partial CCR updates (*i.e.*, either a fly ash conversion or a bottom ash conversion associated with combined ash transport water). Prior to making the partial CCR updates to those five plants, the total combined ash transport water discharge flow is 88 MGD. EPA can't precisely estimate the change in flow for these five plants; however, the total flow for these five plants is approximately 14 MGD.

c – The total ash transport water discharge flow is presented as a range to reflect the difference between the five plants with partial CCR updates. The minimum flow represents the total industry flow excluding the flow associated with the five plants. The maximum flow represents the total industry flow including the flow associated with the five plants.

Table 10-15. Industry-Level Baseline Ash Impoundment Loadings by Type of Impoundment Excluding BOD, COD, TDS, and TSS, Accounting for CPP

Type of Ash Impoundment	Number of Plants	Total Baseline Industry Discharge Flow (MGD)	Total Industry Baseline Loading	
			Pounds/Year	TWPE/Year
Fly Ash				
Fly Ash Pond	8	25	45,900,000	67,800
Combined Ash Pond [a]	N/C [b]	N/C [b]	51,600,000	118,000
Bottom Ash				
Bottom Ash Pond	84	134	228,000,000	323,000
Combined Ash Pond [a]	N/C [b]	N/C [b]	11,700,000	21,600

Table 10-15. Industry-Level Baseline Ash Impoundment Loadings by Type of Impoundment Excluding BOD, COD, TDS, and TSS, Accounting for CPP

Type of Ash Impoundment	Number of Plants	Total Baseline Industry Discharge Flow (MGD)	Total Industry Baseline Loading	
			Pounds/Year	TWPE/Year
TOTAL	**108**	**214-228 [c]**	**337,000,000**	**531,000**

N/C – Not calculated.

Note: Excludes loadings for pollutants not identified as POCs and for BOD, COD, TDS, and TSS.

Note: Loadings are rounded to three significant figures.

a – The combined ash pond loadings were calculated based on the data used in the loadings calculation, but then the total combined ash pond loadings were split between fly ash and bottom ash based on the EPRI data, as described in this section.

b – After incorporating updates based on the CCR rule and CPP, EPA identified a total of 20 plants discharging combined ash transport water from combined ash ponds. EPA reduced the baseline loadings (pounds and TWPE) for three of these plants due to partial CCR updates (*i.e.*, either a fly ash conversion or a bottom ash conversion associated with combined ash transport water). Prior to making the partial CCR updates to those three plants, the total combined ash transport water discharge flow is 69 MGD. EPA can't precisely estimate the change in flow for these three plants; however, the total flow for these three plants is approximately 13 MGD.

c – The total ash transport water discharge flow is presented as a range to reflect the difference between the three plants with partial CCR updates. The minimum flow represents the total industry flow excluding the flow associated with the three plants. The maximum flow represents the total industry flow including the flow associated with the three plants.

Table 10-16 presents the total industry post-compliance loadings and pollutant removals, in both pounds per year and TWPE per year, between the baseline and the dry or closed-loop recycle handling technology option. The pollutant removals are based on the oil-fired generating units and those generating units with a generating capacity of 50 MW or less not installing the technology basis because they are facing no more stringent requirements than already existed under the previously established BPT regulations. EPA calculates the pollutant removals by subtracting the post-compliance loadings from the baseline loadings. The pollutant removals for all generating units installing the technology basis, including the oil-fired generating units and small generating units (*i.e.*, 50 MW or less generating capacity), are presented in EPA's *Incremental Costs and Pollutant Removals for Final Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category* report [U.S. EPA, 2015]. Table 10-17 adjusts the results presented in Table 10-16, accounting for the CPP.

Table 10-16. Estimated Ash Impoundment Pollutant Removals by Regulatory Option Excluding BOD, COD, TDS, and TSS

Regulatory Option [a]	Total Industry Loading		Total Industry Pollutant Removals [b]	
	Pounds/Year	TWPE/Year	Pounds/Year	TWPE/Year
Fly Ash				
All Regulatory Options	1,490,000	2,880	113,000,000	222,000
Bottom Ash				
A, B	354,000,000	509,000	NA	NA
C	139,000,000	198,000	216,000,000	311,000
D, E	1,890,000	2,390	353,000,000	506,000

Note: Excludes loadings for pollutants not identified as POCs and for BOD, COD, TDS, and TSS.

Note: Removals are rounded to three significant figures.

a – Baseline and Regulatory Options A, B, D, and E assume that oil-fired generating units and generating units with a capacity of 50 MW or less do not install the technology basis for all wastestreams. Regulatory Option C assumes that oil-fired generating units and generating units with a capacity of 50 MW or less do not install the technology basis for FGD wastewater treatment and fly ash, while oil-fired generating units and generating units with a capacity of 400 MW or less do not install the technology basis for bottom ash.

b – Compared to baseline.

NA – Not applicable.

Table 10-17. Estimated Ash Impoundment Pollutant Removals by Regulatory Option Excluding BOD, COD, TDS, and TSS, Accounting for CPP

Regulatory Option [a]	Total Industry Loading		Total Industry Pollutant Removals [b]	
	Pounds/Year	TWPE/Year	Pounds/Year	TWPE/Year
Fly Ash				
All Regulatory Options	370,000	631	97,100,000	185,000
Bottom Ash				
A, B	240,000,000	345,000	NA	NA
C	65,800,000	93,900	174,000,000	251,000
D, E	861,000	896	239,000,000	344,000

Note: Excludes loadings for pollutants not identified as POCs and for BOD, COD, TDS, and TSS.

Note: Removals are rounded to three significant figures. The removals may not equal the sum of the removals presented in the tables in this section from the various wastestreams due to rounding.

a – Baseline and Regulatory Options A, B, D, and E assume that oil-fired generating units and generating units with a capacity of 50 MW or less do not install the technology basis for all wastestreams. Regulatory Option C assumes that oil-fired generating units and generating units with a capacity of 50 MW or less do not install the technology basis for FGD wastewater treatment and fly ash, while oil-fired generating units and generating units with a capacity of 400 MW or less do not install the technology basis for bottom ash.

b – Compared to baseline.

NA – Not applicable.

10.4.3 Combustion Residual Leachate Loadings and TWPE

EPA calculated plant-specific loadings for the baseline discharges and main technology option considered for combustion residual leachate by multiplying the plant-specific flow by the concentrations for untreated combustion residual leachate or chemical precipitation effluent. For baseline loadings, EPA multiplied the plant-specific combustion residual leachate discharge flow rate with the average pollutant concentrations that represent untreated combustion residual leachate for impoundments and landfills. EPA identified five plants transferring combustion residual leachate to a POTW. For these five plants, EPA adjusted the baseline loadings to account for pollutant removals associated with POTW treatment.

For the chemical precipitation technology option, EPA assumed that all plants discharging landfill leachate would install that type of treatment system to handle only landfill leachate. No plants currently treat leachate with a chemical precipitation system; however, two plants do operate/plan to operate biological treatment systems to treat landfill leachate, so all but these two plants would need to install treatment to meet the effluent requirements associated with this technology option. EPA calculated discharge loadings for these plants using the average concentration data set associated with chemical precipitation systems, presented in Section 10.2.3, and plant-specific combustion residual landfill leachate flow rates. All combustion residual impoundment leachate discharges would remain unchanged from baseline.

Table 10-18 presents the combustion residual leachate loadings at an industry level for baseline and each post-compliance technology basis. The loadings presented in Table 10-18 are based on the oil-fired generating units and those generating units with a generating capacity of 50 MW or less not installing the technology basis because they are facing no more stringent requirements than already existed under the previously established BPT regulations.[130] The loadings include only pollutants identified as POCs and also exclude the pollutant parameters BOD, COD, TDS, and TSS to avoid double counting the loadings for other specific pollutants. Included in the table is the number of plants discharging combustion residual leachate, the total industry flow rate associated with each technology option, and the total industry loading in pounds per year and TWPE per year. Table 10-19 adjusts the results shown in Table 10-18 to account for the CPP. Table 10-20 presents the pollutant removals, in both pounds per year and TWPE per year, for the technology options. EPA calculated the pollutant removals by subtracting the post-compliance loadings from the baseline loadings. Table 10-21 adjusts the results shown in Table 10-20 to account for the CPP. The loadings for all generating units installing the technology basis, including the oil-fired generating units and small generating units (*i.e.*, 50 MW or less generating capacity), are presented in EPA's *Incremental Costs and Pollutant Removals for Final Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category* report [U.S. EPA, 2015].

[130] EPA evaluated exclusions on a plant level for combustion residual leachate. Those plants identifying all generating units operated at the plant as coal-fired and with a generating capacity of 50 MW or less were assumed not to install the technology basis.

Table 10-18. Industry-Level Combustion Residual Leachate Loadings Excluding BOD, COD, TDS, and TSS and Based on Oil-Fired Units and Units 50 MW or Less Not Installing Technology Basis

Technology Option	Number of Plants	Total Industry Discharge Flow (MGD)	Total Industry Loading	
			Pounds/Year	TWPE/Year
Baseline	95 [a]	9.09	85,400,000	70,300
Chemical Precipitation	95 [a]	9.09	72,900,000	36,400

Note: Excludes loadings for pollutants not identified as POCs and for BOD, COD, TDS, and TSS.

Note: Loadings are rounded to three significant figures.

a – One plant operates only oil-fired generating units and/or generating units with a generating capacity of 50 MW or less; therefore, this plant is not facing any more stringent requirements than exist under the previously established BPT regulations. As such, EPA assumed that this plant will not install the technology basis and, therefore, will not incur any compliance costs. Additionally, EPA assumed it will continue to discharge combustion residual leachate at its current baseline level and will not achieve any pollutant removals for the technology options evaluated.

Table 10-19. Industry-Level Combustion Residual Leachate Loadings Excluding BOD, COD, TDS, and TSS and Based on Oil-Fired Units and Units 50 MW or Less Not Installing Technology Basis, Accounting for CPP

Technology Option	Number of Plants	Total Industry Discharge Flow (MGD)	Total Industry Loading	
			Pounds/Year	TWPE/Year
Baseline	70	7.90	74,100,000	61,000
Chemical Precipitation	70	7.90	63,200,000	31,400

Note: Excludes loadings for pollutants not identified as POCs and for BOD, COD, TDS, and TSS.

Note: Loadings are rounded to three significant figures.

Table 10-20. Combustion Residual Leachate Pollutant Removals Excluding BOD, COD, TDS, and TSS and Based on Oil-Fired Units and Units 50 MW or Less Not Installing Technology Basis

Technology Option	Total Industry Pollutant Removals	
	Pounds/Year	TWPE/Year
Reduction (Baseline –>Chemical Precipitation)	12,500,000	33,800

Note: Excludes loadings for pollutants not identified as POCs and for BOD, COD, TDS, and TSS.

Note: Removals are rounded to three significant figures. The removals may not equal the subtraction of the technology option from the baseline using the values in Table 10-18 due to rounding.

Table 10-21. Combustion Residual Leachate Pollutant Removals Excluding BOD, COD, TDS, and TSS and Based on Oil-Fired Units and Units 50 MW or Less Not Installing Technology Basis, Accounting for CPP

Technology Option	Total Industry Pollutant Removals	
	Pounds/Year	TWPE/Year
Reduction (Baseline –>Chemical Precipitation)	10,900,000	29,600

Note: Excludes loadings for pollutants not identified as POCs and for BOD, COD, TDS, and TSS.

Note: Removals are rounded to three significant figures. The removals may not equal the subtraction of the technology option from the baseline using the values in Table 10-19 due to rounding.

10.4.4 Pollutant Loadings and Removals for Regulatory Options

As described in Section 8, EPA evaluated five main regulatory options comprising various combinations of technology options to control each wastestream. EPA estimated the pollutant removals associated with steam electric power plants to achieve compliance for each of the main regulatory options. Table 10-22 presents the total industry loadings and pollutant removals at baseline and for each of the five regulatory options. The loadings and TWPE values presented in these tables include only pollutants identified as POCs. The table presents the estimated loadings and pollutant removals based on the oil-fired generating units and generating units with a capacity of 50 MW or less not installing the appropriate technology bases. Table 10-23 adjusts the results shown in Table 10-22 to account for the CPP. The loadings and pollutant removals for all generating units installing the technology basis, including the oil-fired generating units and small generating units (*i.e.*, 50 MW or less generating capacity), are presented in EPA's *Incremental Costs and Pollutant Removals for Final Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category* report [U.S. EPA, 2015]. The pollutant-level baseline loadings and pollutant-level removals for each regulatory option by wastestream are presented in the memorandum entitled, "Steam Electric Pollutant-Level Loadings and Removals by Wastestream" [ERG, 2015g].

Table 10-22. Estimated Pollutant Loadings and Removals by Regulatory Option

Regulatory Option [a]	Total Industry Loading		Total Industry Pollutant Removals [b]	
	Pounds/Year	TWPE/Year	Pounds/Year	TWPE/Year
Baseline	2,210,000,000	2,680,000	-	-
A	2,060,000,000	1,650,000	150,000,000	1,030,000
B	2,050,000,000	1,510,000	161,000,000	1,170,000
C	1,830,000,000	1,200,000	376,000,000	1,480,000
D	1,700,000,000	1,000,000	513,000,000	1,680,000
E	1,680,000,000	967,000	526,000,000	1,710,000

Note: Excludes loadings for pollutants not identified as POCs and for BOD, COD, TOC, TDS, and TSS.

Note: Loadings and removals are rounded to three significant figures. The removals may not equal the sum of the removals presented in the tables in this section from the various wastestreams due to rounding.

a – Baseline and Regulatory Options A, B, D, and E assume that oil-fired generating units and generating units with a capacity of 50 MW or less do not install the technology basis for all wastestreams. Regulatory Option C assumes that oil-fired generating units and generating units with a capacity of 50 MW or less do not install the technology basis for FGD wastewater treatment and fly ash, while oil-fired generating units and generating units with a capacity of 400 MW or less do not install the technology basis for bottom ash.

b – Compared to baseline.

Table 10-23. Estimated Pollutant Loadings and Removals by Regulatory Option, Accounting for CPP

Regulatory Option [a]	Total Industry Loading		Total Industry Pollutant Removals [b]	
	Pounds/Year	TWPE/Year	Pounds/Year	TWPE/Year
Baseline	1,700,000,000	2,140,000	-	-
A	1,580,000,000	1,250,000	124,000,000	891,000
B	1,570,000,000	1,130,000	132,000,000	1,010,000
C	1,390,000,000	878,000	306,000,000	1,260,000
D	1,330,000,000	785,000	371,000,000	1,350,000
E	1,320,000,000	755,000	382,000,000	1,380,000

Note: Excludes loadings for pollutants not identified as POCs and for BOD, COD, TOC, TDS, and TSS.

Note: Loadings and removals are rounded to three significant figures. The removals may not equal the sum of the removals presented in the tables in this section from the various wastestreams due to rounding.

a – Baseline and Regulatory Options A, B, D, and E assume that oil-fired generating units and generating units with a capacity of 50 MW or less do not install the technology basis for all wastestreams. Regulatory Option C assumes that oil-fired generating units and generating units with a capacity of 50 MW or less do not install the technology basis for FGD wastewater treatment and fly ash, while oil-fired generating units and generating units with a capacity of 400 MW or less do not install the technology basis for bottom ash.

b – Compared to baseline.

10.4.5 Evaluation of Non-Detected Values on Pollutant Loadings

The sample-specific detection levels for the ash transport water data used for this rule vary widely between samples and across plants. To capture the full range of uncertainty EPA derived estimates of pollutant loadings using two methods. Method 1 uses both the detect and non-detect data (assigning one-half of the detection limit for all non-detects). This is EPA's standard procedure for effluent limitations guidelines as well as Clean Water Act assessment and permitting, Safe Drinking Water Act compliance monitoring, and Resource Conservation and Recovery Act and Superfund programs. Since the detection levels exhibit considerable variance across plants, commenters raised the concern that the loadings data may contain non-detect values that may be significantly higher than the range of observed (i.e., detected) values. Method 2 excludes all non-detect observations whose attributed values (i.e., one-half of the detection limit) are higher than the highest detected value for that pollutant in the data set. EPA conducted analysis using method 2 in order to place an upper bound on the effect of potential outlier non-detects on the pounds of pollutants removed and TWPEs removed under the final rule.

Although method 1 for handling "non-detects" when identifying loadings for this rule is consistent with past precedent, it is important to be transparent about the sensitivity of these results to potential outliers. An outlier is a value that appears to diverge from other observations in the sample. There are normally two types of outliers. The first is an observation that is simply an extreme manifestation of random variation inherent in the data. The second is an observation that is an outlier due to differences in experimental procedure [Greene, 2000]. The first type of outlier is of less concern here, and would be limited to extreme detected values, which one expects to periodically observe. The second type of outlier is of greater concern, as it may not be a natural characteristic of the data.

To isolate the effect of potential outliers for the ash transport water data, EPA used method 2 to calculate the averaged pollutant concentrations. The key consideration in such an analysis is to establish a rational basis for determining if a non-detect value could potentially be considered an outlier. This method used samples where the analyte is detected ("detected values") to evaluate the existence of non-detects that are outliers. The approach we used for this alternative analysis isolates attributed non-detect (i.e., one-half of the detection limit) values that are above the observed sample of detected values. When there are multiple detected values to base this on, such treatment should exclude samples that are outside the normal range of variation. Note that to truly eliminate all outliers, one would also eliminate the outliers that are non-detects ***lower than*** the lowest detected value. Outliers are typically analyzed at both tails of the distribution. However, to assess a reasonable upper-bound on cost-effectiveness by addressing the concerns with the detection sensitivity of sampling instruments, this alternative method focuses only on the high outliers.

EPA first identified the maximum detected value in the dataset for an analyte and then excluded all non-detect values higher than that maximum detected value. The pollutant loadings and cost effectiveness were then recalculated using the detected values and the remaining non-detected values that were lower than the maximum detected value. After discarding non-detects in this manner, calculated results for bottom ash indicate that the mean pollutant concentrations for 6 out of 44 analytes change: antimony (-97.78%), cobalt (-99.08%), molybdenum (-64.41%), silver (-16.57%), thallium (-99.10%), and titanium (-58.75%). EPA notes that, of the six analytes that had their means change, five of them had three or fewer detected values. Based on this small number of detected values, it is not clear whether the excluded non-detects were truly outliers in those cases, as we may not have an accurate distribution of detected data. We also assessed the approach of replacing each of the excluded non-detects with the mean detected value, instead of removing them from the dataset, but that approach yielded only minor differences compared with discarding the non-detect values.

The pollutant concentrations obtained using methods 1 and 2 resulted in the following pollutant removals, as shown in Table 10-24 and Table 10-25.

Table 10-24. Pollutant Removals – Method 1 Not Excluding High ND

	lbs/yr	TWPE/yr
Bottom Ash Transport Water (>50 MW)	238,810,677	344,014
Full Rule (Option D)	371,152,958	1,354,857

Note: Excludes removals for pollutants not identified as POCs and for BOD, COD, TSS, and TDS.

Table 10-25. Pollutant Removals – Method 2 Excluding High ND

	lbs/yr	TWPE/yr
Bottom Ash Transport Water (>50 MW)	238,735,119	236,402
Full Rule (Option D)	371,048,709	1,233,553

Note: Excludes removals for pollutants not identified as POCs and for BOD, COD, TSS, and TDS.

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SECTION 11
POLLUTANTS SELECTED FOR REGULATION

This section describes the selection of regulated pollutants for each wastestream for which EPA is establishing new or revised discharge requirements in the revisions to the Steam Electric effluent limitations guidelines and standards (ELGs). Regulated pollutants are pollutants for which EPA is establishing numerical effluent limitations and standards. This section describes the methodology and rationale EPA used to select the subset of regulated pollutant parameters from the list of pollutants of concern (POCs) for each wastestream. The identification of POCs for each wastestream is presented in Section 6.6 of this document

11.1 SELECTION OF REGULATED POLLUTANTS FOR DIRECT DISCHARGERS

Effluent limitations and standards for all POCs often are not necessary to ensure that wastewater pollution is adequately controlled because many of the pollutants originate from similar sources, have similar treatabilities and are removed by similar mechanisms. Therefore, in some instances, it may be sufficient to establish effluent limitations or standards for one or more indicator pollutants, which will ensure the removal of other POCs. Based on the information in the record, this approach of establishing effluent limitations and standards on a subset of the POCs is appropriate for the discharge of some of the wastestreams regulated by this rule. For wastestreams where the final rule establishes zero discharge limitations or standards, all POCs are directly regulated.

For wastestreams where the final rule establishes numeric effluent limitations or standards (best available technology economically achievable (BAT) or new source performance standards (NSPS)), EPA considered the following when selecting a subset of pollutants as indicators for all regulated pollutants:

- EPA did not set limits for pollutants associated with treatment system additives because regulating these pollutants could interfere with efforts to optimize treatment system operation.
- EPA did not set limits for pollutants for which the treatment technology was ineffective (*e.g.*, pollutant concentrations remained approximately unchanged or increased across the treatment system).
- EPA did not set limits for pollutants that are adequately controlled through the regulation of another indicator pollutant because they have similar properties and are treated by similar mechanisms as the regulated pollutant.

The following sections describe EPA's pollutant selection analysis for each wastestream.

11.1.1 FGD Wastewater

The final rule establishes separate BAT and NSPS limitations and standards for FGD wastewater. BAT limitations are based on a chemical precipitation system followed by anoxic/anaerobic biological treatment as the technology basis and NSPS is based on an evaporation system as the technology basis for the treatment of FGD wastewater, as described in 13.8

BAT Limitations for FGD Wastewater

EPA included BAT limitations for four pollutants (arsenic, mercury, selenium, and nitrate/nitrite as N) for FGD wastewater, and a fifth pollutant (TSS) for legacy FGD wastewater and FGD wastewater discharged by small or oil-fired units.[131] The regulated pollutant selection criteria matrix for the 31 POCs in FGD wastewater for BAT limitations is illustrated in Table 11-1. The following discussion explains the rationale EPA used to select which of the 31 POCs to regulate under BAT for the final rule. EPA acknowledges that a POC may fall under more than one criterion for exclusion as a regulated pollutant (*e.g.*, a pollutant may not be effectively treated by the BAT technology and could also be used as a treatment chemical).

- Conventional Pollutants: EPA identified total suspended solids (TSS) as a POC. The existing BPT limitations adequately control TSS in discharges of FGD wastewater. In addition, EPA set BAT limitations on TSS as an indicator pollutant to control particulate metals in discharges of legacy FGD wastewater (from all generating units) and discharges of FGD wastewater from small generating units and oil-fired generating units. These BAT limitations on TSS are equal to the previously promulgated BPT limitations on TSS for low volume waste sources (which prior to this final rule included FGD wastewater).
- Treatment Chemicals: EPA identified and eliminated five POCs that are also used as treatment chemicals: aluminum, calcium, iron, phosphorus, and sodium.
- Pollutants Not Effectively Treated by the BAT Technology: EPA eliminated five pollutants, ammonia, boron, chloride, cyanide, and total dissolved solids (TDS), because the technology basis for the FGD wastewater effluent limitations and standards is not demonstrated to reliably treat these pollutants.[132]
- Pollutants Directly Regulated or Controlled by Regulation of Other Pollutants: The remaining pollutants are metals, metalloids, or other nonmetals and nitrate/nitrite as N. As described in Section 7, chemical precipitation systems use chemicals to alter the physical state of dissolved and suspended solids to help settle and remove solids from the wastewater. The metals present in the wastewater form insoluble hydroxides and/or sulfide complexes. The solubilities of these complexes vary by pH; therefore, specific pHs can be targeted to remove specific metals. Most metals are precipitated to some degree in the chemical precipitation system, thereby resulting in the removal of a wide range of metals. EPA's design basis for the BAT system uses hydroxide and sulfide precipitation, as well as iron coprecipitation. EPA selected arsenic and

[131] EPA also established BAT limitations for four pollutants (arsenic, mercury, selenium, and TDS) for FGD wastewater for plants that accept the limitations for the voluntary incentives program. The following discussion on "NSPS Limitations for FGD Wastewater" is applicable to the BAT limitations established for the voluntary incentives program.

[132] While EPA's pollutant-specific treatment effectiveness analysis performed for FGD wastewater showed some removal of ammonia, boron, cyanide, chloride, and TDS in the chemical precipitation system (see Section 10.2.1.2 for additional details), EPA has determined that the chemical precipitation system is not demonstrated to reliably treat these pollutants.

mercury as regulated pollutants and as indicators of effective removals of many other pollutants of concern present in FGD wastewater, such as cadmium and chromium. While most metals can be removed to low levels using chemical precipitation alone, other pollutants such as selenium and nitrate/nitrite as N require additional treatment (*i.e.*, biological treatment) to achieve consistent removals. Anaerobic/anoxic biological treatment is effective at removing both selenium and nitrate/nitrite as N and, therefore, EPA also selected both pollutants for regulation.

NSPS Limitations for FGD Wastewater

EPA also included NSPS for four pollutants: arsenic, mercury, selenium, and TDS.

The regulated pollutant selection criteria matrix for the 31 POCs in FGD wastewater for NSPS limitations is illustrated in Table 11-2. The following discussion explains the rationale EPA used to select which of the 31 POCs to regulate under NSPS for the final rule.

- Conventional Pollutants: EPA identified total suspended solids (TSS) as a POC. The previously promulgated limitations (BPT for existing sources; NSPS for new sources as promulgated in 1982) adequately control TSS and those limitations are included in the NSPS included in the revised ELGs.
- Pollutants Not Effectively Treated by the NSPS Technology: EPA eliminated three pollutants: ammonia, cyanide, and phosphorus because the technology basis for the FGD wastewater effluent limitations and standards is not demonstrated to reliably treat these pollutants.
- Pollutants Directly Regulated or Controlled by Regulation of Other Pollutants: The remaining pollutants are metals, metalloids, other nonmetals, nitrate-nitrite as N, chloride, and TDS. As described in Section 7, the evaporation system uses steam to evaporate the water, producing a distillate stream and a solid residual by-product (*i.e.*, crystallized salts). Pollutant removals from this system will depend on the pollutant's solubility and volatility. Pollutants with lower solubility are more easily crystallized and removed as part of the solids residuals. EPA selected four pollutants, arsenic, mercury, selenium, and TDS to represent different solubilities and volatilities of pollutants and act as indicator pollutants for other pollutants. Nitrate-nitrite as N is directly regulated by the BAT limitations for FGD wastewater. For NSPS, however, EPA determined that limitations for TDS would effectively control discharges of nitrate-nitrite as N (which, due to its relatively high solubility and low volatility, concentrate in the brine removed as the moisture content of the solids residuals), as well as other pollutants such as sodium, bromide, and chloride.

Table 11-1. POCs Considered for Regulation for Direct Dischargers (BAT): FGD Wastewater

Pollutant Group	Pollutant of Concern	Treatment Chemical	Not Effectively Treated by the BAT Technology	Directly Regulated or Controlled by Regulation of Another Parameter
Priority Pollutants	Antimony			✓
	Arsenic			✓
	Beryllium			✓
	Cadmium			✓
	Chromium			✓
	Copper			✓
	Cyanide		✓	
	Lead			✓
	Mercury			✓
	Nickel			✓
	Selenium			✓
	Thallium			✓
	Zinc			✓
Nonconventional Pollutants	Aluminum	✓		
	Ammonia		✓	
	Barium			✓
	Boron		✓	
	Calcium	✓		
	Chloride		✓	
	Cobalt			✓
	Iron	✓		
	Magnesium			✓

Table 11-1. POCs Considered for Regulation for Direct Dischargers (BAT): FGD Wastewater

Pollutant Group	Pollutant of Concern	Treatment Chemical	Not Effectively Treated by the BAT Technology	Directly Regulated or Controlled by Regulation of Another Parameter
	Manganese			✓
Nonconventional Pollutants	Molybdenum			✓
	Nitrate/Nitrite as N			✓
	Phosphorus	✓		
	Sodium	✓		
	Titanium			✓
	Total Dissolved Solids		✓	
	Vanadium			✓

Note: The conventional pollutants identified as POCs for FGD wastewater (oil and grease (O&G) and TSS) are not included in the table because conventional pollutants are not regulated under BAT or NSPS limitations and standards.

Table 11-2. POCs Considered for Regulation for Direct Dischargers (NSPS): FGD Wastewater

Pollutant Group	Pollutant of Concern	Treatment Chemical	Not Effectively Treated by the NSPS Technology	Directly Regulated or Controlled by Regulation of Another Parameter
Priority Pollutants	Antimony			✓
	Arsenic			✓
	Beryllium			✓
	Cadmium			✓
	Chromium			✓
	Copper			✓
	Cyanide		✓	
	Lead			✓
	Mercury			✓
	Nickel			✓
	Selenium			✓
	Thallium			✓
	Zinc			✓
Nonconventional Pollutants	Aluminum			✓
	Ammonia		✓	
	Barium			✓
	Boron			✓
	Calcium			✓
	Chloride			✓
	Cobalt			✓
	Iron			✓
	Magnesium			✓

Table 11-2. POCs Considered for Regulation for Direct Dischargers (NSPS): FGD Wastewater

Pollutant Group	Pollutant of Concern	Treatment Chemical	Not Effectively Treated by the NSPS Technology	Directly Regulated or Controlled by Regulation of Another Parameter
	Manganese			✓
Nonconventional Pollutants	Molybdenum			✓
	Nitrate/Nitrite as N			✓
	Phosphorus		✓	
	Sodium			✓
	Titanium			✓
	Total Dissolved Solids			✓
	Vanadium			✓

Note: The conventional pollutants identified as POCs for FGD wastewater (oil and grease (O&G) and TSS) are not included in the table because conventional pollutants are not regulated under BAT or NSPS limitations and standards.

Note: The information in this table is also applicable to BAT limitations for the voluntary incentives program.

11.1.2 Combustion Residual Leachate

The final rule establishes BAT limitations for combustion residual leachate to the current BPT limitations on TSS for low volume waste sources, and NSPS limitations for arsenic and mercury in discharges of new sources of combustion residual leachate based on a chemical precipitation system. The NSPS-regulated pollutant selection criteria matrix for the 25 POCs in combustion residual leachate is illustrated in Table 11-3. The following discussion explains the rationale EPA used to select which of the 25 POCs to regulate under NSPS for the final rule. EPA acknowledges that a POC may fall under more than one criterion for exclusion as a regulated pollutant (*i.e.*, a pollutant may not be effectively treated by the NSPS technology basis and could also used as a treatment chemical).

- Conventional Pollutants: EPA identified TSS as a POC. EPA set BAT limitations on combustion residual leachate from small generating units and oil-generating units equal to the BPT limitations on TSS for low volume waste sources. EPA determined that TSS is adequately controlled by existing BPT limitations (based on low volume waste sources).
- Treatment Chemicals: EPA identified and eliminated four POCs that are also used as treatment chemicals: aluminum, calcium, iron, and sodium.
- Pollutants Not Effectively Treated by the NSPS Technology: EPA eliminated five pollutants, boron, chloride, selenium, sulfate, and TDS, because the technology basis for the combustion residual leachate effluent standards is not demonstrated to reliably treat these pollutants.
- Pollutants Directly Regulated or Controlled by Regulation of Other Pollutants: The remaining pollutants of concern are all metals, metalloids, or other nonmetals. As explained above for FGD wastewater, chemical precipitation is effective at removing metals present in wastewater, especially when both hydroxide and sulfide precipitation mechanisms are used, which is part of the basis for the NSPS technology. EPA selected arsenic and mercury as regulated pollutants and as indicators of effective removals of many other POCs present in combustion residual leachate, such as magnesium and manganese.

Table 11-3. Pollutants Considered for Regulation for Direct Dischargers (NSPS): Combustion Residual Leachate

Pollutant Group	Pollutant of Concern	Treatment Chemical	Not Effectively Treated by the NSPS Technology	Directly Regulated or Controlled by Regulation of Another Parameter
Priority Pollutants	Antimony			✓
	Arsenic			✓
	Cadmium			✓
	Chromium			✓
	Copper			✓
	Mercury			✓
	Nickel			✓
	Selenium		✓	
	Thallium			✓
	Zinc			✓
Nonconventional Pollutants	Aluminum	✓		
	Barium			✓
	Boron		✓	
	Calcium	✓		
	Chloride		✓	
	Cobalt			✓
	Iron	✓		
	Magnesium			✓
	Manganese			✓
	Molybdenum			✓
	Sodium	✓		
	Sulfate		✓	

Table 11-3. Pollutants Considered for Regulation for Direct Dischargers (NSPS): Combustion Residual Leachate

Pollutant Group	Pollutant of Concern	Treatment Chemical	Not Effectively Treated by the NSPS Technology	Directly Regulated or Controlled by Regulation of Another Parameter
Nonconventional Pollutants	Total Dissolved Solids		✓	
	Vanadium			✓

Note: The conventional pollutants identified as POCs for combustion residual leachate (O&G and TSS) are not included in the table because conventional pollutants are not regulated under NSPS.

11.1.3 Gasification Wastewater

The final rule establishes BAT and NSPS limitations and standards for four pollutants: arsenic, mercury, selenium, and TDS. These limitations and standards are based on an evaporation system for direct dischargers. The regulated pollutant selection criteria matrix for the 34 POCs in gasification wastewater is illustrated in Table 11-4. The following discussion explains the rationale EPA used to select which of the 34 POCs to regulate under BAT/NSPS for the final rule.

- Conventional Pollutants: EPA identified biochemical oxygen demand (5-day) (BOD_5) and TSS as POCs. TSS is adequately controlled by existing BPT limitations (based on low volume waste sources). BOD_5 is not subject to BAT limitations.
- Pollutants Not Effectively Treated by the BAT/NSPS Technology: EPA eliminated six pollutants, ammonia, chemical oxygen demand (COD), cyanide, nitrate/nitrite as N, phosphorus, and total Kjeldahl nitrogen (TKN), because the technology basis for the gasification wastewater effluent limitations and standards is not demonstrated to reliably treat these pollutants in gasification wastewater.
- Pollutants Directly Regulated or Controlled by Regulation of Other Pollutants: The remaining pollutants are metals, metalloids, other nonmetals, salt ions (*i.e.*, chloride and sulfate), and TDS. EPA selected three metals, arsenic, mercury, and selenium, to represent different volatilities of pollutants and act as indicator pollutants for other pollutants. EPA also selected TDS for regulation as an indicator of pollutants (*e.g.*, sodium, chloride, bromide) present in the wastewater.

Table 11-4. Pollutants Considered for Regulation for Direct Dischargers (BAT/NSPS): Gasification Wastewater

Pollutant Group	Pollutant of Concern	Treatment Chemical	Not Effectively Treated by the BAT/NSPS Technology	Directly Regulated or Controlled by Regulation of Another Parameter
Priority Pollutants	Antimony			✓
	Arsenic			✓
	Beryllium			✓
	Cadmium			✓
	Copper			✓
	Cyanide		✓	
	Lead			✓
	Mercury			✓
	Nickel			✓
	Selenium			✓
	Thallium			✓
	Zinc			✓
Nonconventional Pollutants	Aluminum			✓
	Ammonia		✓	
	Barium			✓
	Boron			✓
	Calcium			✓
	Chemical Oxygen Demand		✓	
	Chloride			✓
	Cobalt			✓
	Iron			✓

Table 11-4. Pollutants Considered for Regulation for Direct Dischargers (BAT/NSPS): Gasification Wastewater

Pollutant Group	Pollutant of Concern	Treatment Chemical	Not Effectively Treated by the BAT/NSPS Technology	Directly Regulated or Controlled by Regulation of Another Parameter
Nonconventional Pollutants	Magnesium			✓
	Manganese			✓
	Molybdenum			✓
	Nitrate/Nitrite as N		✓	
	Nitrogen, Kjeldahl (TKN)		✓	
	Phosphorus		✓	
	Sodium			✓
	Sulfate			✓
	Titanium			✓
	Total Dissolved Solids			✓
	Vanadium			✓

Note: The conventional pollutants identified as POCs for gasification wastewater (BOD_5 and TSS) are not included in the table because conventional pollutants are not regulated under BAT or NSPS limitations and standards.

11.2 REGULATED POLLUTANT SELECTION METHODOLOGY FOR INDIRECT DISCHARGERS

Before establishing pretreatment standards for existing sources (PSES) or pretreatment standards for new sources (PSNS) for a pollutant, EPA examines whether the pollutant "passes through" a publicly owned treatment works (POTW) to waters of the U.S. or interferes with the POTW operation or sludge disposal practices. In determining whether a pollutant passes through POTWs for these purposes, EPA generally compares the percentage of a pollutant removed by well-operated POTWs performing secondary treatment to the percentage removed by the BAT/NSPS technology basis. A pollutant is determined to pass through POTWs when the median percentage removed nationwide by well-operated POTWs is less than the median percentage removed by the BAT/NSPS technology basis. Pretreatment standards are established for those pollutants regulated under BAT/NSPS that pass through POTWs.

Under this rule, for those wastestreams regulated with a zero discharge standard, EPA set the percentage removed by the technology basis at 100 percent. Because a POTW would not be able to achieve 100 percent removal of wastewater pollutants, it is appropriate to set PSES as zero discharge; otherwise, pollutants would pass through the POTW.

For wastestreams for which EPA established numerical limitations, EPA determined the pollutant percentage removed by the rule's technology basis for pollutants selected for regulation for BAT (PSES) or NSPS (PSNS). The following pollutants were not analyzed for pass through even if selected for regulation under BAT/NSPS: BOD_5, TSS, and oil and grease. POTWs are designed to treat these pollutants; therefore, they were not considered to pass through.

The following sections present the POTW pass-through analysis:

- Methodology for determining BAT percent removals.
- Methodology for determining POTW percent removals.
- Results of the POTW pass-through analysis.

11.2.1 <u>Methodology for Determining BAT Percent Removals</u>

EPA calculated percent removals for each selected technology option using the same data it used to determine the long-term averages (LTAs) and effluent limitations and standards for the selected BAT or NSPS technology. Therefore, EPA subjected the data used to calculate the treatment technology percent removals to the same data editing criteria as the data used to establish the effluent limitations and standards (see Section 13).

1. For each pollutant and each plant for which EPA had influent and effluent data, EPA averaged the influent data and effluent data to obtain a plant-specific average influent and effluent concentration, respectively.

2. EPA calculated percent removals for each pollutant and for each model plant from the site-specific average influent and effluent concentrations using the following equation:

$$\text{PercentRemoval} = \frac{\text{AverageInfluentConcentration - AverageEffluentConcentration}}{\text{AverageInfluentConcentration}} \text{ x } 100$$

3. If EPA calculated percent removals for multiple model plants for a pollutant, EPA used the median percent removal for that pollutant from the plant-specific percent removals as the BAT or NSPS technology percent removal.

11.2.2 Methodology for Determining POTW Percent Removals

EPA generally calculated pollutant percent removals at POTWs nationwide from two available data sources:

- Fate of Priority Pollutants in Publicly Owned Treatment Works, September 1982, EPA 440/1-82/303 (50 POTW Study). [U.S. EPA, 1982]
- National Risk Management Research Laboratory (NRMRL) Treatability Database, Version 5.0, February 2004 (formerly called the Risk Reduction Engineering Laboratory (RREL) database). [U.S. EPA, 2004]

When available for a pollutant, EPA used data from the 50 POTW Study. For those pollutants not covered in the 50 POTW Study, EPA used NRMRL data. The 50 POTW Study presents data on the performance of 50 well-operated POTWs that use secondary treatment to remove pollutants. EPA edited the data to minimize the possibility that low POTW removals might simply reflect low influent concentrations instead of treatment effectiveness. Below are the criteria used in editing the 50-POTW study data for this:

1. Substitute the standardized pollutant-specific minimum analytical detection limit (ML) for values reported as “not detected,” “trace,” “less than (followed by a number),” or a number less than the ML.
2. Retain pollutant influent and corresponding effluent values if the average pollutant influent level is greater than or equal to 10 times the pollutant ML.
3. If none of the average pollutant influent concentrations are at least 10 times the pollutant ML, then retain average influent values greater than or equal to two times the pollutant ML along with corresponding effluent data.

For each POTW that had data pairs that passed the editing criteria, EPA calculated its percent removal for each pollutant using the equation provided above. EPA then used the median value of all the POTW pollutant-specific percent removals as the nationwide percent removal in its pass-through analysis. For this pass-through analysis, EPA used the 50-POTW study data for arsenic and mercury, which are two times the pollutant ML and 10 times the pollutant ML, respectively.

The NRMRL database, used to augment the POTW database for the pollutants that the 50 POTW Study did not cover, is a computerized database that provides information, by pollutant, on removals obtained by various treatment technologies. The database provides the user with the specific data source and the industry from which the wastewater was generated. For each of the pollutants regulated under the BAT level of control that were not found in the 50-POTW database (*i.e.*, selenium and nitrate/nitrite as N), EPA used data from portions of the NRMRL database. EPA applied the following editing criteria:

1. Only treatment technologies representative of typical POTW secondary treatment operations (activated sludge, activated sludge with filtration, aerated lagoons) were used.
2. Only information pertaining to domestic wastewater was used.
3. Pilot-scale and full-scale data were used, while bench-scale data were eliminated.
4. Only data from peer-reviewed journals or government reports were used.

Using the NRMRL pollutant removal data that passed the above criteria, EPA calculated the average percent removal for selenium and nitrate compounds for nitrate/nitrite as N.

Neither source includes pollutant removal data for TDS. Secondary treatment technologies are generally understood to be ineffective at removing TDS and as such TDS removals at POTWs are likely to be close to zero. For purposes of this pass-through analysis, EPA assumes the percent removal to be zero [Metcalf & Eddy, 2003].

11.2.3 Results of POTW Pass-Through Analysis

The following sections provide the results of EPA's pass through analyses for FGD wastewater, combustion residual leachate, and gasification wastewater using the methodology described above. EPA did not conduct its traditional pass-through analysis for wastestreams with zero discharge limitations or standards. Zero discharge limitations and standards achieve 100 percent removal of pollutants; therefore, all pollutants in those wastestreams pass through the POTW.

FGD Wastewater

The technology basis for PSES for FGD wastewater is chemical precipitation followed by biological treatment. Table 11-5 presents the BAT treatment technology percent removals and POTW removals for FGD wastewater. Because the FGD wastewater BAT effluent limitations and standards for arsenic and mercury were transferred from the chemical precipitation system, EPA performed the pass-through analysis for arsenic and mercury based on the pollutant removals achieved by the chemical precipitation system. All four regulated pollutants were determined to pass through POTW secondary treatment and EPA selected them as regulated pollutants for PSES.

Table 11-5. POTW Pass-Through Analysis (FGD Wastewater) – PSES

Pollutant	Median BAT % Removal	POTW % Removal	BAT % Removal > POTW % Removal?	Does Pollutant Pass Through?
Arsenic	98.9% [a]	65.8%	Yes	Yes
Mercury	99.9% [a]	90.2%	Yes	Yes
Nitrate/Nitrite as N	98.7%	90.0%	Yes	Yes
Selenium	99.8%	34.3%	Yes	Yes

Source: ERG, 2015.

a – The arsenic and mercury BAT percent removals are based on the chemical precipitation treatment, because the BAT effluent limitations were transferred from the chemical precipitation system.

The technology basis for PSNS for FGD wastewater is evaporation. EPA calculated the NSPS treatment technology percent removals based on the one plant currently operating the technology basis. EPA compared the median percent removal to the POTW removals for FGD wastewater. Table 11-6 presents the NSPS treatment technology percent removals and POTW removals for FGD wastewater. All four regulated pollutants were determined to pass through POTW secondary treatment and EPA selected them as regulated pollutants for PSNS.

Table 11-6. POTW Pass-Through Analysis (FGD Wastewater) – PSNS

Pollutant	Median NSPS % Removal	POTW % Removal	NSPS % Removal > POTW % Removal?	Does Pollutant Pass Through?
Arsenic	96.3%	65.8%	Yes	Yes
Mercury	99.9%	90.2%	Yes	Yes
TDS [a]	99.9%	0%	Yes	Yes
Selenium	99.2%	34.3%	Yes	Yes

Source: ERG, 2015.

a – EPA does not expect POTWs to effectively remove TDS; therefore, EPA set POTW percent removal for TDS to zero and assumed this POC passes through POTW secondary treatment.

<u>Combustion Residual Leachate</u>

The technology basis for PSNS for combustion residual leachate is chemical precipitation. As explained further in Section 13, EPA is transferring the effluent standards for combustion residual leachate from the chemical precipitation technology option for FGD wastewater. Therefore, for arsenic and mercury, the technology basis percent removals for combustion residual leachate are based on the removals achieved by the chemical precipitation system for FGD wastewater. Table 11-7 presents the treatment option percent removals and POTW removals for combustion residual leachate using the methodology described above. Both mercury and arsenic pass through and EPA is establishing PSNS for both pollutants.

Table 11-7. POTW Pass-Through Analysis (Combustion Residual Leachate) – PSNS

Pollutant	Median BAT % Removal	POTW % Removal	BAT % Removal > POTW % Removal?	Does Pollutant Pass Through?
Arsenic	98.9 % [a]	65.8%	Yes	Yes
Mercury	99.9% [a]	90.2%	Yes	Yes

Source: ERG, 2015.

a – The arsenic and mercury BAT percent removals are based on FGD wastewater chemical precipitation treatment, because the NSPS were transferred from the FGD wastewater chemical precipitation system.

Gasification Wastewater

The technology option for gasification wastewater is evaporation. Table 11-8 presents the technology option percent removals and POTW removals for gasification wastewater. All four regulated pollutants were determined to pass through POTW secondary treatment and EPA is establishing PSES and PSNS for all four pollutants.

Table 11-8. POTW Pass-Through Analysis (Gasification Wastewater) – PSES/PSNS

Pollutant	Median BAT % Removal	POTW % Removal	BAT % Removal > POTW % Removal?	Does Pollutant Pass Through?
Arsenic	99.4%	65.8%	Yes	Yes
Mercury	98.5%	90.2%	Yes	Yes
Selenium	88.9%	34.3%	Yes	Yes
TDS	99.7%	0%	Yes	Yes

Source: ERG, 2015.

11.3 REFERENCES

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3. U.S. EPA. 2004. National Risk Management Research Laboratory (NRMRL) Treatability Database, Version 5.0. (February).
4. ERG. 2015. Eastern Research Group. Pass-through analysis summary (spreadsheet). (30 September). DCN SE05896.

SECTION 12
NON-WATER QUALITY ENVIRONMENTAL IMPACTS

The elimination or reduction of one form of pollution has the potential to aggravate other environmental problems, an effect frequently referred to as cross-media impacts. Sections 304(b) and 306 of the Clean Water Act (CWA) require EPA to consider non-water quality environmental impacts (NWQIs), including energy impacts, associated with effluent limitations guidelines and standards (ELGs). Accordingly, EPA has considered the potential impact of the final rule on energy consumption (including fuel usage), air emissions, and solid waste generation.[133] In addition, EPA evaluated the effects associated with water use.

EPA determined that the NWQIs associated with the ELGs are acceptable. The sections below summarize the NWQIs associated with the ELG requirements for FGD wastewater, combustion residual leachate, and fly ash and bottom ash transport water. Because all plants generating flue gas mercury control (FGMC) wastewater and gasification wastewater currently operate the technologies identified as the basis for BAT, the ELGs will not result in any net increase of energy or fuel usage, solid waste generation, or air emissions for these wastestreams. As described throughout this section, although the ELGs will result in increases of energy and fuel usage, solid waste generation, and air emissions, the increases are small compared to national levels of energy/fuel usage, current air emissions from power plants, and current solid waste generation from steam electric power plants.[134] In addition, EPA evaluated the effect of the technology options on water use and found that the resulting reductions or elimination of water use would lead to improvements in water availability in water-stressed areas.

12.1 ENERGY REQUIREMENTS

Steam electric power plants use energy (including fuel) when transporting ash and other solids on or off site, operating wastewater treatment systems, operating ash handling systems, or operating water trucks for dust suppression. For those plants that are projected to incur costs associated with the final rule, EPA considered whether or not there would be an associated incremental energy need. That need varies depending on the regulatory option evaluated and the current operations of the plant. Therefore, as applicable, EPA estimated the additional energy usage in megawatt hours (MWh) for equipment added to the plant systems or in consumed fuel (gallons) for transportation or equipment operation. Similarly, as applicable, EPA also estimated the decrease in energy use that would result from ceasing wet-sluicing operations and reduced use of earthmoving equipment. EPA summed the plant-specific estimate to calculate the net increase in energy requirements for the regulatory options considered for the final rule.

To determine potential increases in electrical energy use, EPA estimated the amount of energy needed to operate wastewater treatment systems and dry or closed-loop ash handling systems. EPA estimated electrical energy use from horsepower ratings of system equipment (*e.g.*, pumps, mixers, silo unloading equipment). See EPA's *Incremental Costs and Pollutant*

[133] EPA also evaluated the effect of this rule on energy and fuel usage, solid waste generation, and air emissions for new sources. For more information on the NWQIs that EPA evaluated for new sources, see EPA's memorandum "Steam Electric Non-Water Quality Impacts for New Sources" [ERG, 2015a].

[134] The final rule will also result in decreases of air emissions for certain pollutants.

Removals for the Final Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category for more information on the specific calculations used to estimate energy needed to operate wastewater treatment systems and dry or closed-loop ash handling systems [U.S. EPA, 2015a]. To determine potential decreases in electrical energy use, EPA estimated the amount of energy saved from ceasing wet-sluicing operations, including the wet-sluicing handling system equipment and earthmoving equipment (*e.g.*, front-end loader) operation at applicable surface impoundments. EPA estimated electrical energy use from horsepower ratings of wet-sluicing system pumps and the earthmoving equipment engine. EPA estimated energy savings associated with only earthmoving equipment for plants sending FGD solids, fly ash, or bottom ash to surface impoundments. See EPA's memorandum "Steam Electric Effluent Guidelines Non-Water Quality Impacts" for more information on the specific calculations used to estimate energy savings from ceasing wet-sluicing operations [ERG, 2015b].Table 12-1 presents the net annual change in annual electrical energy usage associated with the main regulatory options considered for the final regulation. Table 12-2 adjusts the results shown in Table 12-1, accounting for expected closures related to the implementation of the proposed Clean Power Plan (CPP) (referred to hereafter as "Accounting for CPP").

Energy usage also includes the fuel consumption associated with transportation. EPA estimated the need for increased transportation of solid waste and combustion residuals (*e.g.*, ash) at steam electric power plants to on-site or off-site landfills, based on plant-specific data, using open dump trucks. In general, EPA calculated fuel usage based on the estimated amount of time spent loading and unloading solid waste and combustion residuals and the fuel consumption during idling plus the estimated total transportation distance, number of trips required per year to dispose of the solid waste and combustion residuals, and fuel consumption. The frequency and distance of transport depends on a plant's operation and configuration. For example, the volume of waste generated per day determines the frequency with which trucks will be travelling to and from the storage sites. The availability of either an on-site or off-site landfill, and its estimated distance from the plant, determines the length of travel time. See EPA's memorandum "Steam Electric Effluent Guidelines Non-Water Quality Impacts" for more information on the specific calculations used to estimate fuel consumption associated with the transport and disposal of solid waste and combustion residuals [ERG, 2015b].

EPA also estimated fuel consumption associated with the dust suppression water trucks based on the total distance (in miles) traveled and the total number of hours estimated for water truck operations. See EPA's *Incremental Costs and Pollutant Removals for the Final Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* report for more information on the specific calculations used to estimate water truck fuel usage [U.S. EPA, 2015a]. Table 12-1 shows the net change in national annual fuel consumption associated with the main regulatory options considered for the final rule. Table 12-2 adjusts the results shown in Table 12-1, accounting for CPP.

Table 12-1. Industry-Level Energy Requirements by Regulatory Option

Non-Water Quality Impact	Energy Use Associated with ELG				
	Option A	Option B	Option C	Option D	Option E
Electrical Energy Usage (MWh)	59,400	140,000	248,000	339,000	373,000
Fuel (Gallons Per Year (GPY))	168,000	169,000	498,000	758,000	766,000

Table 12-2. Industry-Level Energy Requirements by Regulatory Option, Accounting for CPP

Non-Water Quality Impact	Energy Use Associated with ELG				
	Option A	Option B	Option C	Option D	Option E
Electrical Energy Usage (MWh)	51,700	102,000	187,000	237,000	264,000
Fuel (GPY)	133,000	134,000	442,000	556,000	563,000

To provide some perspective on the potential net increase in annual electric energy consumption associated with the regulatory options, EPA compared the estimated increase in energy usage (MWh), as shown in Table 12-1 and Table 12-2, to the net amount of electricity generated in a year by all electric power plants throughout the United States. According to EPA's Emissions & Generation Resource Integrated Database (eGRID), the electric power industry generated approximately 3,951 million MWh of electricity in 2009. EPA estimates that energy increases associated with the selected BAT and PSES regulatory option (Regulatory Option D) is less than 0.01 percent of the total electricity generated by all electric power plants in 2009 [ERG, 2015b].

Similarly, EPA compared the additional net fuel consumption (gallons) estimated for the regulatory options, as shown in Table 12-1 and Table 12-2, to national fuel consumption estimates for motor vehicles in the United States. According to the U.S. Energy Information Administration (EIA), on-highway vehicles, which include automobiles, trucks, and buses, consumed approximately 34 billion gallons of distillate fuel oil in 2009. EPA estimates that the fuel consumption increase associated with Regulatory Option D for BAT and PSES will be 0.002 percent of total fuel consumption by all motor vehicles in the United States [ERG, 2015b].

12.2 Air Emissions Pollution

The final rule is expected to affect air pollution through three main mechanisms:

- Additional auxiliary electricity use by steam electric power plants to operate wastewater treatment, ash handling, and other systems needed to comply with the ELGs.
- Additional transportation-related emissions due to the increased trucking of combustion residual waste to landfills.

- The change in the profile of electricity generation due to relatively higher costs to generate electricity at plants incurring compliance costs for the ELGs.

This section provides greater detail on air emission changes associated with the first two mechanisms and presents the estimated net change in air emissions that take all three mechanisms into account. See EPA's *Benefit and Cost Analysis for the Final Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Categor*y for additional discussion of the third mechanism [U.S. EPA, 2015b].

Air pollution is generated when fossil fuels are combusted. In addition, steam electric power plants generate air emissions from operating transport vehicles, such as dump trucks and vacuum trucks, dust suppression water trucks, and earthmoving equipment, which release criteria air pollutants and greenhouse gases when operated. Criteria air pollutants are those pollutants for which a national ambient air quality standard (NAAQS) has been set and include sulfur dioxide (SO_2) and nitrogen oxides (NOx). Greenhouse gases are gases such as carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O) that absorb radiation, thereby trapping heat in the atmosphere, and contributing to global warming.[135] Conversely, decreasing energy use or vehicle operation will result in decreased air pollution.

EPA calculated air emissions resulting from increased auxiliary electricity using year-explicit emission factors projected by the Integrated Planning Model (IPM)[136] for CO_2, NO_x, and SO_2. The IPM output provides emission factors by plant and North American Electric Reliability Corporation (NERC) region that EPA used to determine potential changes in air emissions under the final rule. EPA used three IPM run years to reflect variance in annual air emission factors at different stages after rule implementation for years 2020, 2025, and 2030. These IPM outputs were used to estimate plant-specific and NERC region emission factors for the corresponding IPM run years.

EPA assumed that plants with capacity utilization rates (CUR) of 90.4 percent or less would generate the additional auxiliary electricity on site and therefore estimated emissions using plant-specific and year-explicit emission factors obtained from IPM outputs.[137]

EPA assumed that plants with CUR greater than 90.4 percent would draw additional electricity for auxiliary power from the grid within the NERC region instead of generating it on site. These plants will be using part of its existing generation to power equipment; however, other plants within the same NERC region would need to generate electricity to compensate for this reduction and meet electricity demands. Therefore, EPA used NERC-average emission factors for each year instead of plant-specific emissions factors.

[135] EPA did not specifically evaluate nitrous oxide emissions as part of the NWQI analysis. To avoid double counting air emission estimates, EPA calculated only nitrogen oxide emissions, which would include nitrous oxide emissions.

[136] IPM is a comprehensive electricity market optimization model that can evaluate cost and economic impacts within the context of regional and national electricity markets. IPM is used by EPA to analyze the projected impact of environmental policies on the U.S. power sector.

[137] Emission factors are calculated as plant-level emissions divided by plant-level generation.

EPA calculated NO_X, CO_2, and SO_2 emissions resulting from changes in auxiliary power use based on the incremental auxiliary power electricity consumption, the pollutant-specific emission factors, and the timing plants are assumed to install the compliance technology between 2019 and 2023 and start incurring additional electricity consumption. Similarly, EPA estimated the average emission factors for the United States for these three time periods. See the memorandum entitled “Steam Electric Effluent Guidelines Non-Water Quality Impacts” [ERG, 2015b] for more information about EPA’s methodology for estimating air emissions and IPM’s emission factors for each regulatory option.

Because IPM was run for Regulatory Options B and D only, EPA used IPM emission factors for Regulatory Option B to estimate changes in auxiliary power air emissions for Regulatory Option A and IPM emissions factors for Regulatory Option D to estimate changes in auxiliary power air emissions for Regulatory Options C and E. The NWQI air emissions associated with changes in auxiliary power presented in this document correspond to the year 2025. EPA selected 2025 because it is the closest run year to the implementation of the rule.

To estimate air emissions associated with increased operation of transport vehicles, EPA used the MOBILE6.2 model to generate air emission factors (grams per mile) for NO_x, CO_2, and SO_X. EPA assumed the general input parameters such as the year of the vehicle and the annual mileage accumulation by vehicle class to develop these factors. See EPA’s report entitled *Incremental Costs and Pollutant Removals for the Final Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* for more specific information on the assumptions EPA made for year of the vehicle and annual mileage accumulation [U.S. EPA, 2015a]. Because MOBILE6.2 does not estimate emission factors for CH_4, EPA used the emission factors from the California Climate Action Registry, General Reporting Protocol, Version 2.2. Table 12-3 lists the transportation emission factors for each air pollutant considered in the NWQI analysis.

Table 12-3. MOBILE6.2 and California Climate Action Registry Transportation Emission Rates

NO_X Highway (ton/mi)	NO_X Local (ton/mi)	SO_X (ton/mi)	CO_2 (ton/mi)	CH_4 (ton/mi)
6.76×10^{-7}	6.52×10^{-7}	1.58×10^{-8}	0.0017	6.61×10^{-8}

Source: MOBILE6.2 [U.S. EPA, 2004] and California Climate Action Registry, General Reporting Protocol, V2.2 [California Climate Action Registry, 2007].

Note: The MOBILE6.2 highway and local emission rates are the same for all pollutants except nitrogen oxides.

EPA calculated the air emissions associated with increased operation of transport vehicles estimated for the regulatory options using the transportation pollutant-specific emission rate per mile, the estimated round trip distance to and from the on-site or off-site landfill, and the number of calculated trips for one year in the transportation methodology to truck all solid waste or combustion residuals to the on-site or off-site landfill.

EPA estimated the annual number of miles that dump or vacuum trucks moving ash or wastewater treatment solids to on- or off-site landfills would travel to comply with limits associated with the main regulatory options. In addition to the trucks transporting the additional solid waste, EPA also estimated the annual number of miles that water trucks spraying water around landfills and ash unloading areas to control dust would travel. EPA used these estimates to calculate the net increase in air emissions for this rulemaking. See EPA's memorandum "Steam Electric Effluent Guidelines Non-Water Quality Impacts" for more information on the specific calculations used to estimate transport distance and number of trips per year [ERG, 2015b]. The increases in national annual air emissions associated with auxiliary electricity and transportation for each of the regulatory options are shown in Table 12-4. Table 12-5 adjusts the results shown in Table 12-4, accounting for CPP.

Table 12-4. Industry-Level Air Emissions Associated with Auxiliary Electricity and Transportation by Regulatory Option

Non-Water Quality Impact	Air Emissions Associated with the ELG				
	Option A	Option B	Option C	Option D	Option E
NO_X (tons/year)	34.8	71.5	141	196	215
SO_X (tons/year)	44.3	93	158	212	236
CO_2 (metric tons/year)	49,300	104,000	194,000	244,000	268,000
CH_4 (tons/year)	0.866	1.96	3.54	4.86	5.32

Table 12-5. Industry-Level Air Emissions Associated with Auxiliary Electricity and Transportation by Regulatory Option, Accounting for CPP

Non-Water Quality Impact	Air Emissions Associated with the ELG				
	Option A	Option B	Option C	Option D	Option E
NO_X (tons/year)	31.1	60.0	118	167	186
SO_X (tons/year)	42.7	86.7	148	196	220
CO_2 (metric tons/year)	45,800	90,600	169,000	213,000	237,000
CH_4 (tons/year)	0.745	1.43	2.68	3.40	3.77

EPA estimated the change in the profile of electricity generation due to relatively higher costs to generate electricity at plants incurring compliance costs for the ELG using data from IPM. IPM predicts changes in electricity generation due to costs to comply with the regulatory options. Therefore, EPA predicts that these changes, either increases or decreases, in electricity generation affect the air emissions from steam electric power plants. EPA estimated only the changes associated with the IPM predications, one of the three air emission mechanisms, for Regulatory Options B and D. The net changes in industry-level annual air emissions associated with the selected regulatory options are shown in Table 12-6. Table 12-7 adjusts the results shown in Table 12-6, accounting for CPP.

Table 12-6. Industry-Level Net Air Emissions for Regulatory Options B and D

Non-Water Quality Impact	Air Emissions Associated with the ELG	
	Option B	Option D
NO_x (tons/year)	-3,250	-11,400
SO_x (tons/year)	-435	2,450
CO_2 (metric tons/year)	-1,330,000	-2,310,000
CH_4 (tons/year)	1.96	4.86

Table 12-7. Industry-Level Net Air Emissions for Regulatory Options B and D, Accounting for CPP

Non-Water Quality Impact	Air Emissions Associated with the ELG	
	Option B	Option D
NO_x (tons/year)	-3,260	-11,400
SO_x (tons/year)	-441	2,430
CO_2 (metric tons/year)	-1,350,000	-2,340,000
CH_4 (tons/year)	1.43	3.40

To provide some perspective on the potential increase in annual air emissions associated with the regulatory options, EPA compared the estimated increase in air emissions associated with Regulatory Options B and D to the net amount of air emissions generated in a year by all electric power plants throughout the United States. Table 12-8 presents the 2009 emissions generated by the electric power generating industry, based on eGRID, and the percentage of increased emissions associated with the final rule [U.S. EPA, 2012a]. Table 12-9 adjusts the results shown in Table 12-8, accounting for CPP.

Table 12-8. Electric Power Industry Air Emissions

Non-Water Quality Impact	Value Associated with Selected Regulatory Option (Million Tons)	2009 Emissions by Electric Power Generating Industry (Million Tons)	Increase In Emissions (%)
Option B			
NO_x	-0.00325	1	-0.326
SO_x	-0.000435	6	-0.00724
CO_2	-1.46	2,403	-0.0612
CH_4	0.00000195	95	0.00000206
Option D			
NO_x	-0.0114	1	-1.16
SO_x	0.00245	6	0.0408
CO_2	-2.55	2,403	-0.106
CH_4	0.00000485	95	0.0000051

Table 12-9. Electric Power Industry Air Emissions, Accounting for CPP

Non-Water Quality Impact	Value Associated with Selected Regulatory Option (Million Tons)	2009 Emissions by Electric Power Industry (Million Tons)	Increase In Emissions (%)
Option B			
NO_x	-0.00326	1	-0.327
SO_x	-0.000441	6	-0.00735
CO_2	-1.48	2,403	-0.0618
CH_4	0.00000143	95	0.00000151
Option D			
NO_x	-0.0114	1	-1.16
SO_x	0.00243	6	0.0406
CO_2	-2.58	2,403	-0.108
CH_4	0.0000034	95	0.00000358

12.3 SOLID WASTE GENERATION

Steam electric power plants generate solid waste associated with sludge from wastewater treatment systems (*e.g.*, chemical precipitation, biological treatment, vapor compression evaporation). The regulatory options evaluated would increase the amount of solid waste generated from FGD and combustion residual leachate wastewater treatment, including sludge from chemical precipitation and/or biological treatment. EPA estimated the amount of solid waste generated from each technology for each plant and estimates that the BAT/PSES regulatory options (Regulatory Options A through E) would increase solids generated annually from treatment. Fly and bottom ash are also solid wastes generated at steam electric power plants. The regulatory options for BAT and PSES are; however, not expected to alter the amount of ash or other combustion residuals generated.

See Sections 6 and 9 of EPA's report titled *Incremental Costs and Pollutant Removals for the Final Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* for the specific FGD and combustion residual leachate sludge generation calculations, respectively [U.S. EPA, 2015a]. The net change in national annual sludge production associated with the regulatory options is shown in Table 12-10. Table 12-11 adjusts the results shown in Table 12-10, accounting for CPP.

To provide some perspective on the potential increase in annual solid waste generation associated with Regulatory Option D, EPA compared the estimated increase in solid waste generation to the amount of solids generated in a year by electric generating power plants throughout the United States. According to the EIA, power plants generated approximately 134 billion tons of solids in 2009. EPA estimates that solid waste generation increases associated with the regulatory options will be less than 0.001 percent of the total solid waste generated by all electric power plants.

Table 12-10. Industry-Level Solid Waste Increases by Regulatory Option

Non-Water Quality Impact	Solid Waste Generation with the ELG				
	Option A	Option B	Option C	Option D	Option E
Sludge (Tons/Year)	583,000	596,000	596,000	596,000	794,000

Table 12-11. Industry-Level Solid Waste Increases by Regulatory Option, Accounting for CPP

Non-Water Quality Impact	Solid Waste Generation with the ELG				
	Option A	Option B	Option C	Option D	Option E
Sludge (Tons/Year)	514,000	525,000	525,000	525,000	698,000

12.4 REDUCTIONS IN WATER USE

Steam electric power plants generally use water for handling solid waste, including ash, and for operating wet FGD scrubbers. The technology options for fly and bottom ash transport water will eliminate or reduce water use associated with wet ash sluicing operating systems. EPA estimated the reductions in water use by calculating the amount of ash transport water, specifically the amount of water identified as intake process water, that will no longer be discharged as part of the final rulemaking. To calculate this reduction, EPA used data from the *Questionnaire for the Steam Electric Power Generating Effluent Guidelines* (Steam Electric Survey) to calculate an average percentage of ash transport water identified as intake water. EPA multiplied this percentage by the amount of transport water discharged by each plant to calculate the estimated process water reduction. See the memorandum entitled "Steam Electric Effluent Guidelines Non-Water Quality Impacts" [ERG, 2015b] for more information.

The technology basis for the selected BAT regulatory option with respect to FGD wastewater discharges (*e.g.*, chemical precipitation, biological treatment) would not be expected to reduce the amount of water used unless plants recycle FGD wastewater as part of their treatment system. EPA estimated that three plants will choose to reuse some of the FGD wastewater within the FGD system based on the maximum operating chlorides concentration compared to the design maximum chlorides concentration (other plants may also be able to do so). To estimate the water reductions associated with the recycled FGD wastewater, EPA used data from the Steam Electric Survey to calculate an average percentage of FGD wastewater identified as intake water. EPA multiplied this percentage by the amount of water that could be recycled by the FGD system to calculate the estimated water reduction. EPA also used the adjusted FGD scrubber purge flows to estimate compliance cost and pollutant loadings associated with these plants. See EPA's report entitled *Incremental Costs and Pollutant Removals for the Final Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* for more information [U.S. EPA, 2015a].

EPA estimates that power plants would reduce the use of water associated with the implementation of the regulatory options. Table 12-12 presents the expected reduction in process water use for each regulatory option evaluated for the ELGs. Table 12-13 adjusts the results shown in Table 12-12, accounting for CPP. For a comparison to the estimated amount of intake water reduction, Table 12-14 presents the estimated amount of wastewater discharged as estimated for the baseline loadings presented in Section 10.

Table 12-12. Industry-Level Process Water Reduction by Regulatory Option

Non-Water Quality Impact	Water Reduction with the ELG				
	Option A	Option B	Option C	Option D	Option E
Water Reduction (Million Gallons/Day)	44.9	44.9	143	223	223

Table 12-13. Industry-Level Process Water Reduction by Regulatory Option, Accounting for CPP

Non-Water Quality Impact	Water Reduction with the ELG				
	Option A	Option B	Option C	Option D	Option E
Water Reduction (Million Gallons/Day)	36.3	36.3	114	155	155

Table 12-14. Estimated Wastewater Discharges at Steam Electric Power Plants

Type of Wastewater	Total Baseline Industry Discharge Flow (Million Gallons/Day)	Total Baseline Industry Discharge Flow, Accounting for CPP (Million Gallons/Day)
FGD Wastewater	41.7	32.4
Ash Transport Water	298-315	214-228
Landfill and Impoundment Leachate	9.09	7.90

Further, EPA's Office of Policy (OP) National Center for Environmental Economics (NCEE) completed a study on the impacts of the Steam Electric ELGs on water withdrawals from both surface waterbodies and aquifers in water stressed areas. Because a number of steam electric power plants are located in regions that experience regular or intermittent drought conditions, NCEE analyzed the exposure of steam electric power plants to drought-related conditions and quantified the reduced water intake in water-stressed areas. NCEE first analyzed plants that would reduce water intake under Regulatory Option D with at least one week of water-stressed conditions and found that an annual average of 50 to 53 billion gallons of water would no longer be withdrawn from drought-prone areas. Additionally, NCEE analyzed plants that would reduce water intake under Regulatory Option D under water-stressed conditions for 5 to 10 weeks and found that an annual average of 27 to 29 billion gallons of water would no longer be withdrawn from drought-prone areas.

NCEE also found that water availability can have several other indirect effects including higher electricity prices, increased pollutant emissions, and the impingement and entrainment of aquatic organisms. For more information, see NCEE's analysis "Water Withdrawals in Water Stressed Areas: Impacts of the Steam Electric Effluent Limitations Guidelines" [NCEE, 2015].

12.5 References

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SECTION 13
LIMITATIONS AND STANDARDS: DATA SELECTION AND CALCULATION

This section describes the data sources, data selection, and statistical methodology EPA used to calculate the long-term average, variability factors, and limitations and standards for existing and new sources in the final steam electric ELGs. The effluent limitations guidelines and standards are based on long- term average effluent values and variability factors that account for reasonable variation in treatment performance within a particular treatment technology over time. For simplicity, in the remainder of this section, the final effluent limitations and/or standards are referred to as "limitations." Also, the term "option long-term average" and "option variability factor" are used to refer to the long-term averages and variability factors for the treatment technology options for an individual waste stream rather than the regulatory options described in Section 8.1.

Section 13.1 provides a brief overview of the criteria EPA used to evaluate and select model plants employing the model treatment technologies (and the associated datasets) forming the basis for the final limitations. Certain data from these model plants were used to calculate the final limitations. Section 13.2 describes why and how EPA either excluded or substituted certain data in calculating the limitations. Section 13.3 presents the procedures that EPA used for aggregating data. Section 13.4 describes data editing criteria that EPA used to select plant datasets in developing the limitations. Sections 13.5 and 13.6 provide an overview of and discuss the procedure for estimating the long-term averages, variability factors, and limitations, respectively. Section 13.7 describes the rationale for "transferring" limitations in certain cases. Sections 13.8 and 13.9 summarize the limitations and engineering review of the limitations, respectively.

13.1 DATA SELECTION

In developing the long-term averages, variability factors, and limitations for a particular waste stream and a technology option, EPA used wastewater data from plants operating the model treatment technology forming the basis for a particular technology option (either Best Available Technology Economically Achievable (BAT) or Best Available Demonstrated Control Technology (BADCT)). The data sources evaluated include: (i) a sampling program during which EPA collected samples (hereafter referred to as "EPA sampling"); (ii) a sampling program during which EPA, pursuant to section 308 of the Clean Water Act, directed plants to collect samples (hereafter referred to as "CWA 308 sampling"); and (iii) self-monitoring data that plants collected and analyzed (hereafter referred to as "plant self-monitoring").

13.1.1 <u>Data Selection Criteria</u>

This section describes the criteria that EPA applied in selecting plants and data to use as the basis for the limitations for flue gas desulfurization (FGD), combustion residual leachate, and gasification waste streams. EPA has used these, or similar criteria, in developing limitations for other industries. EPA uses these criteria to select data that reflect performance of the model technology in treating the industrial wastes under normal operating conditions.

The first criterion requires that the plant have the model technology and that it is generally well operated. Applying this criterion typically eliminates any plant with treatment other than the model technology. EPA generally determines whether a plant meets this criterion based upon site visits, discussions with plant management, and/or comparison to the characteristics, operation, and performance of treatment systems at other plants. EPA often contacts plants to determine whether data submitted represented normal operating conditions for the plant and equipment.

The second criterion generally requires that the influents and effluents from the treatment components represent typical wastewater from the industry, without incompatible wastewater from other sources. Applying this criterion enables EPA to select only those plants where the commingled wastewaters are not characterized by substantial dilution, sudden large variation in wastewater flow rates (i.e., slug loads) that can result in frequent upsets and/or overloads, or wastewaters with different types of pollutants than those generated by the waste stream for which EPA is establishing effluent limitations.

The third criterion typically ensures that the pollutants are present in the influent at sufficient concentrations to evaluate treatment technology effectiveness. To evaluate whether the data meet this criterion for the final rule, EPA often uses a long-term average test (or LTA test) for plants where EPA possesses both influent and effluent data. EPA has used this test in developing regulations for other industries (e.g., the ELGs for the Iron and Steel Point Source Category) (EPA 2002). The test measures the influent concentrations to ensure a pollutant is present at sufficient concentration to evaluate treatment effectiveness. If a dataset for a pollutant fails the test, EPA excludes the data for that pollutant at that plant when calculating the limitations. See Section 13.4 for a detailed discussion of the LTA test.

The fourth criterion typically requires that the data are valid and appropriate for their intended use (e.g., the data must be analyzed with a sufficiently sensitive method). Also, EPA does not use data associated with periods of treatment upsets because such data do not reflect the performance of well-operated treatment systems. In applying the fourth criterion, EPA may evaluate the pollutant concentrations, analytical methods and the associated quality control/quality assurance data, flow values, mass loadings, plant logs, and other available information. As part of this evaluation, EPA reviews the process or treatment conditions that may have resulted in extreme values (high and low). Consequently, EPA may exclude data associated with certain time periods or other data outliers that reflect poor performance or analytical anomalies by an otherwise well-operated site.

EPA also applies the fourth criterion in its review of data corresponding to the initial commissioning period for treatment systems. When installing a new treatment system, most industries undergo a commissioning period to acclimate and optimize the system. During this acclimation and optimization process, the effluent concentration values can be highly variable with occasional extreme values (high and low). This occurs because the treatment system typically requires some "tuning" as the plant staff and equipment and chemical vendors work to determine the optimum chemical addition locations and dosages, vessel hydraulic residence times, internal treatment system recycle flows (e.g., filter backwash frequency, duration, and flow rate; return flows between treatment system components), and other operational conditions including clarifier sludge wasting protocols. It may also take treatment system operators several weeks or months to gain expertise in operating the new treatment system, which also contributes to treatment system variability during the commissioning period. After this initial adjustment period, the system should operate at steady state with relatively low variability around a long-term average over many years. Because commissioning periods typically reflect operating conditions unique to the first time the treatment system begins operation, EPA generally excludes such data in developing the limitations.[138] Similarly, power plant decommissioning periods represent unique operating conditions associated with the permanent shutdown of the power plant, FGD system, and FGD wastewater treatment system,[139] and do not represent best available control technology economically achievable/new source performance standards (BAT/NSPS) level of performance for treatment of FGD wastewater at an operating steam electric power plant. Therefore, EPA also excludes data collected during the plant decommissioning period in calculating the limitations.

13.1.2 Data Selection for Each Technology Option

This section discusses the data selected for use in developing the limitations for each pollutant for each technology option. An abbreviated description of the technology options that were considered as the basis for numeric effluent limitations more stringent than the previously promulgated ELGs in 40 CFR 423 is presented below in this section. See Section 8.2 for a more complete discussion of the basis of each of the technology options considered.

For fly ash transport water, bottom ash transport water, and flue gas mercury control (FGMC) wastewater, the ELGs require zero discharge of pollutants based on dry handling or closed-loop technologies; therefore, EPA did not use effluent concentration data to establish the limitations for these waste streams.

[138] Examples of conditions that are typically unique to the initial commissioning period include operator unfamiliarity or inexperience with the system and how to optimize/adjust its performance to deal with influent wastewater variability and changing conditions, as well as the initial startup of newly installed equipment to ensure components operate as intended. These conditions differ from those associated with the restart of an already commissioned treatment system, such as may occur from a treatment system that has undergone either short or extended duration shutdown (e.g., on the order of days, weeks, or even months). In this latter situation, the plant has already established typical operating practices and set points for treatment system components and operators have experience operating the treatment system and adjusting its operation to deal with changing conditions. Any variability unique to restarting the treatment system can be accommodated, if necessary, by operational practices that include closer monitoring of treatment system operating parameters and recirculating any off-specification effluent back through the treatment system.

[139] Note that decommissioning periods for an individual generating unit at a multi-unit plant are not the same as a plant decommissioning period because wastes from normal operation of the remaining unit(s) will continue. Examples of conditions that are unique to the power plant decommissioning periods include the complete shutdown, cleaning, decommissioning, and possibly dismantling of the equipment and processes used to generate electricity (e.g., boiler operations) which is likely to cause erratic operation of the treatment system. In addition, plant decommissioning would include draining and decommissioning the treatment system itself. These conditions differ from those associated with the periodic shutdown of generating units and other systems at a plant, whether they be for short or extended duration shutdown (e.g., on the order of days, weeks, or even months). In this latter situation, the plant has already established typical operating practices and set points for treatment system components and operators have experience operating the treatment system and adjusting its operation to deal with changing conditions. Any variability unique to the shutdown period can be accommodated, if necessary, by operational practices that include closer monitoring of treatment system operating parameters and recirculating any off-specification effluent back through the treatment system.

For combustion residual leachate, the final rule establishes limitations for new sources based on chemical precipitation treatment. The chemical precipitation treatment technology option considered for combustion residual leachate is a combination of hydroxide precipitation, iron coprecipitation, and sulfide precipitation designed to remove heavy metals. EPA did not identify any power plants using that technology to treat combustion residual leachate. Therefore, EPA transferred the limitations that EPA calculated based on the use of the chemical precipitation technology option to treat FGD wastewater. See Section 13.7 for a detailed discussion of the transfer of limitations, and Section 13.7.1 for a discussion specifically about the combustion residual leachate limitations.

For FGD wastewater, EPA evaluated three technology options: chemical precipitation (as described above for combustion residual leachate); the combination of chemical precipitation and anoxic/anaerobic biological treatment; and the combination of chemical precipitation, softening, and vapor-compression evaporation. The ELGs establish limitations for existing sources (BAT/PSES) based on the combination of chemical precipitation and biological treatment (hereafter biological treatment). For the reasons described in Section 13.7.2. EPA transferred the limitations for two pollutants (arsenic and mercury) that the Agency calculated based on the use of the chemical precipitation technology option to treat FGD wastewater. For the other BAT/PSES limitations applicable to FGD wastewater (selenium and nitrate-nitrite as N), EPA used data from plants employing the model biological treatment technology. The ELGs establish limitations for new sources (NSPS/PSNS) based on the combination of chemical precipitation, softening, and vapor-compression evaporation.

For gasification wastewater, the final rule establishes limitations for new sources based on the combination of chemical precipitation, softening, and vapor-compression evaporation.

In certain instances, the final rule establishes limitations for wastewater discharges that are equal to previously established best practicable control technology currently available (BPT) limitations for total suspended solids (TSS). EPA used no new effluent concentration data to establish limitations that are set equal to BPT limitations for TSS; therefore, such limitations are not discussed in this section. See Section 8 for a more complete discussion of the basis for the final regulatory options.

EPA used specific data sources to calculate the limitations for the different FGD wastewater and gasification wastewater treatment technologies. The data sources used to calculate effluent limitations for each technology option, by wastestream, are described below.

FGD Wastewater

EPA conducted on-site wastewater sampling, or directed plants to collect samples for laboratory analysis by EPA-contracted laboratories, to evaluate the performance of FGD wastewater treatment systems at the 10 plants listed below. In some cases, EPA also obtained self-monitoring data for the treatment systems at the plants. These plants were selected for EPA's sampling program because the information available to EPA at the start of the sampling program indicated that the processes and operations at the plants were representative of other plants in the steam electric industry, and that their FGD wastewater treatment systems were potential candidates for the technology basis for BAT/BADCT effluent limitations. As described below, EPA subsequently determined that the treatment systems at some of the plants do not reflect the technology bases of the technology options considered for BAT or BADCT.

- Four plants operate chemical precipitation treatment systems that include hydroxide precipitation, sulfide precipitation, and iron coprecipitation. These four plants are:
  - Duke Energy's Miami Fort Station (hereafter referred to as Miami Fort).
  - RRI Energy's Keystone Generating Station (hereafter referred to as Keystone).
  - Allegheny Energy's Hatfield's Ferry Power Station (hereafter referred to as Hatfield's Ferry).
  - We Energy's Pleasant Prairie Power Plant (hereafter referred to as Pleasant Prairie).

- Two plants operate a treatment system that includes chemical precipitation followed by anoxic/anaerobic biological treatment designed to remove selenium. These two plants are:
  - Duke Energy Carolina's Belews Creek Steam Station (hereafter referred to as Belews Creek).
  - Duke Energy Carolina's Allen Steam Station (hereafter referred to as Allen).

- One plant operates a treatment system that includes chemical precipitation followed by a sequencing batch reactor (SBR) biological treatment designed to remove nutrients, but not selenium. This plant is:
  - Mirant Mid-Atlantic's Dickerson Generating Station (hereafter referred to as Dickerson).

- Two plants operate a treatment system that includes vapor-compression evaporation, with the evaporation part of the treatment system comprised of two evaporator stages: brine concentration and forced-circulation crystallization. These two plants are:
  - Enel's Federico II Power Plant, located in Brindisi, Italy (hereafter referred to as Brindisi).
  - A2A's Centrale di Monfalcone Plant, located in Monfalcone, Italy (hereafter referred to as Monfalcone).
- One plant operates a treatment system that includes vapor-compression evaporation, but with only one stage of evaporation: brine concentration (the resulting brine at this plant is mixed with ash and landfilled). This plant is:
  - Kansas City Power & Light's Iatan Generating Station (hereafter referred to as Iatan).

For the chemical precipitation technology option, EPA evaluated treatment system influent and effluent data for the four chemical precipitation plants listed above, as well as influent and effluent data for the chemical precipitation treatment stage for the three plants listed above that operate some form of biological treatment. The data for these seven treatment systems, as well as other data evaluated for the ELGs, showed that chemical precipitation systems that include both hydroxide and sulfide precipitation achieve better removals of mercury and other pollutants than treatment systems that use only hydroxide precipitation. Because of this, EPA determined the basis of the technology option should include both hydroxide and sulfide precipitation, as well as iron coprecipitation (iron coprecipitation further enhances pollutant removals in the treatment system). The only plants that include all elements of the technology option are the four chemical precipitation plants (Miami Fort, Keystone, Hatfield's Ferry, and Pleasant Prairie) and, therefore, EPA used the data from these plants to calculate effluent limitations for the technology option. None of the three biological treatment plants include sulfide precipitation as part of their chemical precipitation treatment stage and, therefore, data from Allen, Belews Creek, or Dickerson do not represent treatment that includes all elements of the chemical precipitation technology option. Additionally, during the EPA sampling episode, the Dickerson plant experienced a significant treatment system upset that adversely affected the effluent quality. The sludge bed in the clarifier overturned, releasing previously settled solids (particulates, along with formerly dissolved pollutants that had precipitated from solution following chemical addition) and increasing the effluent pollutant concentrations. A treatment system upset such as this is not indicative of a well-operated system. As a result, EPA did not use data from Allen, Belews Creek, or Dickerson to calculate effluent limitations for arsenic and mercury for the chemical precipitation technology option.

For the biological treatment technology option, EPA evaluated treatment system influent and effluent data for the three biological treatment plants listed above. The biological treatment system at Dickerson is a sequencing batch reactor (SBR) designed for nutrient removal and it is not designed for effective removal of selenium. EPA's sampling data confirmed that the SBR treatment system does not effectively remove selenium. Because EPA's basis for the technology option includes anoxic/anaerobic biological treatment to remove selenium, and the Dickerson plant's treatment system is not designed to effectively remove this pollutant, EPA did not use data from this system in developing the limitations based on biological treatment. The treatment systems at Allen and Belews Creek include chemical precipitation followed by anoxic/anaerobic biological treatment designed to remove selenium, which is the technology basis for the biological treatment technology option. Therefore, EPA used data from Allen and Belews Creek to calculate effluent limitations for selenium and nitrate-nitrite as N for the biological treatment technology option.[140]

For the vapor-compression evaporation technology option, EPA evaluated treatment system data from three plants: Brindisi, Monfalcone, and Iatan. Brindisi operates a treatment system that is the basis for the technology option: a chemical precipitation system followed by softening and a vapor-compression evaporation system. EPA used the data from Brindisi to develop limitations based on the vapor-compression evaporation technology option for arsenic, mercury, selenium, and total dissolved solids (TDS). The Monfalcone plant also operates a treatment system that includes the elements that are the basis for the technology option; however, EPA has only one day of sampling data for this plant. As a result, EPA does not have sufficient data from this plant for use in developing effluent limitations. The treatment system at Iatan (which at the time of EPA's sampling program was the only plant in the United States using evaporation technology to treat FGD wastewater) does not represent the technology that is the

[140] EPA transferred the limitations for arsenic and mercury for the biological (chemical precipitation followed by anoxic/anaerobic biological treatment) technology option from the chemical precipitation technology option. See Section 13.7.2 for a detailed discussion of the transfer of the limitations.

basis for the vapor-compression evaporation technology option and was not used for the limitations development. Iatan operates a solids removal process prior to the vapor-compression evaporation system, but includes neither a full chemical precipitation system nor a softening step to pretreat the wastewater (i.e., to remove a substantial portion of the pollutants, especially the dissolved pollutants) prior to sending it to the evaporator. Furthermore, this plant operates a one-stage evaporation system and, instead of using a second stage of evaporation to crystallize and remove salts and other pollutants from the concentration brine, mixes the brine with fly ash and sends it to the landfill for disposal.

Gasification Wastewater

For the treatment of gasification wastewater using a vapor-compression evaporation system, EPA evaluated systems from the following two plants as part of the EPA sampling program. At the time of EPA's sampling program, these were the only two integrated gasification combined cycle (IGCC) plant operating in the United States.[141]

- Tampa Electric Company's Polk Station (hereafter referred to as Polk).
- Wabash Valley Power Association's Wabash River Station (hereafter referred to as Wabash River).

EPA determined that both Polk and Wabash River use treatment systems that are representative of the basis for the vapor-compression evaporation technology option for gasification, and thus data from these plants were used to develop the limitations for this technology option.

13.1.3 Combining Data from Multiple Sources within a Plant

For this rulemaking, data for most of the model plants came from multiple sources including EPA sampling, CWA 308 sampling, or plant self-monitoring. For five plants (Allen, Belews Creek, Hatfield's Ferry, Miami Fort, and Pleasant Prairie), data from multiple sources were collected during overlapping time periods and EPA combined these data into a single dataset for the plant. For one plant (Keystone), the multiple sources of data were collected during non-overlapping time periods. At Keystone, EPA and CWA 308 samples were collected from September 2010 through January 2011 and arsenic self-monitoring data were available from January 2012 through April 2014. EPA has no information to indicate that these time periods represent different operating conditions; therefore, EPA also combined the multiple sources of data for Keystone into a single dataset for the plant. This approach is consistent with EPA's traditional approach for other effluent guidelines rulemakings.[142] For three plants (Brindisi, Polk,

[141] A third IGCC plant, Duke Energy's Edwardsport plant, commenced commercial operation in June 2013. The gasification wastewater treatment system at Edwardsport includes evaporation, as well as additional treatment such as cyanide destruction. A fourth IGCC plant, Mississippi Power's Kemper County plant, is projected to begin operating in 2016 and reportedly will be a zero discharge plant.

[142] When EPA obtains data from multiple sources (such as the EPA sampling, CWA 308 sampling, and plant self-monitoring data in this rulemaking) from a plant for the same time period, EPA usually combines the data from these sources into a single dataset for the plant for the statistical analyses. In some cases where the sampling data from a plant are collected over two or more distinct time periods, EPA may analyze the data from each time period separately. In some past effluent guidelines rulemakings, EPA analyzed data as if each time period represented a

and Wabash River) that had data from a single source, it was not necessary to combine data. For a list of all the data and their sources (e.g., EPA sampling data) for each of the plants, see the document entitled *Sampling Data Used as the Basis for Effluent Limitations for the Steam Electric Rulemaking* [U.S. EPA, 2015a].

13.2 DATA EXCLUSIONS AND SUBSTITUTIONS

The sections below describe why and how EPA either excluded or substituted certain data in calculating the limitations. Other than the data exclusions described in this section and the data excluded due to failing the data editing criteria (described in Section 13.4), EPA used all the data from the plants discussed in Section 13.1.2.

13.2.1 Data Exclusions

After selecting the model plant(s), EPA applied the data selection criteria described in Section 13.1.1 by thoroughly evaluating all available data for each model plant. EPA identified certain data that warranted exclusion from calculating the limitations because: (i) the samples were analyzed using an analytical method that is not approved in 40 CFR Part 136 for National Pollutant Discharge Elimination System (NPDES) purposes; (ii) the samples were analyzed using a method that was not a sufficiently sensitive analytical method (e.g., EPA Method 245.1 for mercury in effluent samples); (iii) the samples were analyzed in a manner that resulted in an unacceptable level of analytical interferences; (iv) the samples were collected during the initial commissioning period for the treatment system or during the plant decommissioning period; (v) the analytical results were identified as questionable due to quality control issues, abnormal conditions or treatment upsets, or were analytical anomalies; (vi) the samples were collected from a location that is not representative of treated effluent (e.g., secondary clarifier instead of final effluent); or (vii) the treatment system was operating in a manner that does not represent BAT/NSPS level of performance. See DCN SE05733 for a detailed discussion and list of the data that were excluded from development of limitations.

13.2.2 Data Substitutions

In general, EPA used detected values or sample-specific detection limits (i.e., sample-specific quantitation limit, or QL) for non- detected values in calculating the limitations.[143] However, there were some instances in which EPA substituted a baseline value for a detected value or a sample-specific detection limit that was lower than the baseline value. Baseline substitution accounts for the possibility that certain detected or non-detected results may be at a lower concentration than generally can be reliably quantified by well-operated laboratories. This approach is consistent with the way EPA has calculated limitations in previous effluent guidelines rulemakings and is intended to avoid establishing an effluent limitation that could be

different plant when the data were considered to represent fundamentally different operating conditions. This was not the case for the Keystone data, so EPA combined all data for the plant into a single dataset.

[143] For the purpose of the discussion of calculating the long-term averages, variability factors, and effluent limitations, the term "detected" refers to analytical results measured and reported above the sample-specific quantitation limit (QL). The term "non-detected" refers to values that are below the method detection limit (MDL) and also those measured by the laboratory as being between the MDL and the QL.

biased toward a lower concentration than plants can reliably demonstrate compliance with.[144] After excluding all the necessary data as described in Section 13.2.1, EPA compared each reported result to a baseline value. Whenever a detected value or sample-specific detection limit was lower than the baseline value, EPA used the baseline value instead and classified the value as non-detected (even if the actual reported result was a detected value). For example, if the baseline value was 5 micrograms/liter (µg/L) and the laboratory reported a detected value of 3 µg/L, EPA's calculations would treat the sample result as being non-detected with a sample-specific detection limit of 5 µg/L.

EPA used the following baseline values for each pollutant in the development of the effluent limitations for the steam electric rulemaking:

- Arsenic: 2 µg/L.
- Mercury: 0.5 nanogram/liter (ng/L).
- Nitrate-nitrite as N: 0.05 milligram/liter (mg/L).
- Selenium: 5 µg/L.
- TDS: 10 mg/L.

EPA determined the baseline values for mercury, nitrate-nitrite as N, and TDS using the minimum levels (MLs) established by the analytical methods used to obtain the reported values or a comparable analytical method where an ML was not specified by the method.[145] The baseline values for arsenic and selenium are based on the results of MDL studies conducted by well-operated commercial laboratories using EPA Method 200.8 to analyze samples of synthetic FGD wastewater [CSC, 2013].

It should be noted that in cases when all concentration values are above the baseline value, then the baseline value would have no effect on the concentration values and subsequent calculated limitations. Effluent data for mercury and TDS were all above the baseline values; therefore, EPA did not substitute any baseline values when calculating limitations for these parameters. The document entitled *Sampling Data Used as the Basis for Effluent Limitations for*

[144] For example, if a daily maximum limit were established at a concentration lower than the baseline value, although some laboratories might be able to achieve sufficiently low quantitation levels, it is possible that typical well-operated laboratories could not reliably measure down to that level. In such cases, a plant would not be able to demonstrate compliance with the limit. A similar situation might arise with monthly average limitations, particularly if the limit is at a concentration near the baseline value. EPA does not intend to suggest that the baseline value should be established at a level that every laboratory in the country can measure to, or that limitations established for the ELGs must be established sufficiently high that every laboratory in the country must be able to measure to that concentration; however, it is appropriate to use baseline values that generally can be reliably quantified by well-operated laboratories. This approach achieves a reasonable balance in establishing limitations that are representative of treatment system performance and protective of the environment, while at the same time ensuring that plants have adequate access to laboratories with the analytical capabilities necessary to reliably demonstrate compliance with the limitations.

[145] The baseline values for mercury and nitrate-nitrite as N are equal to the MLs specified in EPA Methods 1631E and 353.2, respectively. The method EPA used to analyze for TDS (Standard Method 2540C) does not explicitly state a MDL or ML. However, EPA Method 160.1 is similar to Standard Method 2540C and the lower limit of its measurement range is 10 mg/L (i.e., the nominal quantitation limit). Thus, EPA used 10 mg/L as the baseline value for TDS.

the Steam Electric Rulemaking [U.S. EPA, 2015a] provides a list of all the effluent data used to calculate the limitations, as well as how the values were adjusted using baseline substitution.

In addition to calculating the limitations for each pollutant for each technology option adjusting for the baseline values shown above, when appropriate, EPA also calculated effluent limitations using all the valid reported results (i.e., without substituting baseline values and/or changing the censoring classification of the result). As noted above, the reason for substituting baseline values is generally to prevent establishing an effluent limitation that is biased toward a lower concentration than plants can reliably demonstrate compliance with. After employing baseline substitution, the effluent limitation is often unchanged but sometimes is adjusted upward slightly. For the datasets used in developing limitations for the steam electric ELGs, using baseline substitution raised the calculated limitations in a few instances.[146] In certain other instances, however, EPA found that using baseline substitution had the opposite and unexpected effect of lowering the limitations.[147] This downward effect on the effluent limitations occurred because, although using baseline substitution increased the long-term average value slightly, it also reduced the variability of the dataset, and the resulting net effect was a lower effluent limitation. This means that using baseline substitution in such instances would result in a lower effluent limitation than EPA would otherwise calculate directly from the unadjusted dataset. Because EPA wanted to ensure that plants can achieve the effluent limitations established by the rule, EPA calculated and evaluated both the baseline-adjusted and unadjusted limitations for each technology option and used the higher of the two results for the final ELGs. EPA's comparison of the baseline-adjusted and unadjusted effluent limitations is presented in the Statistical Support Document: Effluent Limitations for FGD Wastewater, Gasification Wastewater, and Combustion Residual Leachate for the Final Steam Electric Power Generating Effluent Limitations Guidelines and Standards.

13.3 DATA AGGREGATION

EPA used daily values in developing the limitations. In cases with at least two samples per day, EPA mathematically aggregated these samples to obtain a single value for that day (the procedure to aggregate the samples is described in sections below). There are instances in the sampling data used in this rulemaking when there are multiple sample results available for a given day. This occurred with field duplicates, overlaps between plant self-monitoring and EPA sampling, or overlaps between plant self-monitoring and CWA 308 sampling.

When aggregating the data, EPA took into account whether each value was detected (D) or non-detected (ND). Measurements reported as being less than the sample-specific detection limit (or baseline values, as appropriate) are designated as non-detected (ND) for the purpose of statistical analyses to calculate the limitations. In the tables and data listings in this document and in the rulemaking record, EPA uses the indicators D and ND to denote the censoring type for detected and non-detected values, respectively.

[146] This occurs for the selenium limitations for gasification wastewater and for FGD wastewater based on evaporation technology.

[147] This occurs for selenium and nitrate-nitrite as N in FGD wastewater (based on biological treatment technology) and for arsenic in FGD wastewater based on chemical treatment technology.

The sections below describe each of the different aggregation procedures. They are presented in the order that the aggregation was performed (i.e., field duplicates were aggregated first and then any overlaps between plant self-monitoring and EPA sampling data or CWA 308 sampling were aggregated).

13.3.1 Aggregation of Field Duplicates

During the EPA sampling episodes, EPA collected field duplicate samples as part of the quality assurance/quality control activities. Field duplicates are two samples collected for the same sampling point at approximately the same time. The duplicates are assigned different sample numbers, and they are flagged as duplicates for a single sampling point at a plant. Because the analytical data from a duplicate pair are intended to characterize the same conditions at a given time at a single sampling point, EPA averaged the data to obtain one value for each duplicate pair.

For arsenic at Hatfield's Ferry and arsenic and mercury from Miami Fort, there were a few days with two or three reported self-monitoring samples. These self-monitoring samples from the same day were treated as duplicate samples in the calculations.

In most cases, the duplicate samples had the same censoring type, so the censoring type of the aggregated value was the same as that of the duplicates. In some instances, one duplicate was a detected (D) value and the other duplicate was a non-detected (ND) value. When this occurred, EPA determined that the aggregated value should be treated as detected (D) because the pollutant is confirmed to be present at a level above the sample-specified detection limit in one of the duplicates. The document entitled *Sampling Data Used as the Basis for Effluent Limitations for the Steam Electric Rulemaking* lists the data before the aggregation as well as after the aggregation [U.S. EPA, 2015a].

Table 13-1 summarizes the procedure for aggregating the sample measurements from the field duplicates. Aggregating the duplicate pairs was the first step in the aggregation procedures for both influent and effluent measurements.

Table 13-1. Aggregation of Field Duplicates

If the Field Duplicates Are:	Censoring Type of Average Is:	Value of the Aggregate Is:	Formulas for Aggregate Values of Duplicates
Both Detected	D	Arithmetic average of measured values.	$(D_1 + D_2)/2$
Both Non-Detected	ND	Arithmetic average of sample-specific detection limit (or baseline).	$(DL_1 + DL_2)/2$
One Detected and One Non-Detected	D	Arithmetic average of measured value and sample-specific detection limit (or baseline).	$(D + DL)/2$

D – Detected.

ND – Non-detected.

DL – Sample-specific detection limit.

13.3.2 Aggregation of Overlapping Samples

At the Allen, Belews Creek, Hatfield's Ferry, Miami Fort, and Pleasant Prairie plants, sampling data were available from EPA sampling, CWA 308 sampling, and plant self-monitoring. As explained in Section 13.1.3, there was some overlap between the data from these sources. On some days at a given plant, samples were available from two sources, specifically plant self-monitoring and either EPA sampling or CWA 308 sampling. When these overlaps occurred, EPA aggregated the measurements from the available samples to obtain one value for that day. The document entitled *Sampling Data Used as the Basis for Effluent Limitations for the Steam Electric Rulemaking* lists the data before the aggregation as well as after the aggregations [U.S. EPA, 2015a].

The procedure averaged the measurements to obtain a single value for that day. When both measurements had the same censoring type, then the censoring type of the aggregate was the same as that of the overlapping values. When one or more measurements were detected (D), EPA determined that the appropriate censoring type of the aggregate was detected because the pollutant was confirmed to be present at a level above the sample-specific detection limit in one of the samples. The procedure for obtaining the aggregated value and censoring type is similar to the procedure shown in Table 13-1.

13.4 DATA EDITING CRITERIA

After excluding and aggregating the data, EPA applied data editing criteria on a pollutant-by-pollutant basis to select the datasets to be used for developing the limitations for each technology option. These criteria are referred to as the long-term average test (or LTA test). EPA often uses the LTA test to ensure that the pollutants are present in the influent at sufficient concentrations to evaluate treatment effectiveness at the plant for the purpose of calculating effluent limitations. By applying the LTA test, EPA ensures that the limitations result from treatment of the wastewater and not simply the absence or substantial dilution of that pollutant in the wastestream. For each pollutant for which EPA calculated a limitation, the influent first had to pass a basic requirement that 50 percent of the influent measurements for the pollutant had to be detected at any concentration. If the dataset at a plant passed the basic requirement, then the data had to pass one of the following two criteria to pass the LTA test:

- Criterion 1. At least 50 percent of the influent measurements in a dataset at a plant were detected at levels equal to or greater than 10 times the baseline value described in Section 13.2.2.
- Criterion 2. At least 50 percent of the influent measurements in a dataset at a plant were detected at any concentration and the influent arithmetic average was equal to or greater than 10 times the baseline value (described in Section 13.2.2).

If the dataset at a plant failed the basic requirement, then EPA automatically set both Criteria 1 and 2 to "fail," and it excluded the plant's effluent data for that pollutant when calculating limitations. If the dataset for a plant failed the basic requirement, or passed the basic requirement but failed both criteria, EPA would exclude the plant's effluent data for that pollutant when calculating limitations.

After performing the LTA test for the regulated pollutants at each model plant employing treatment representing the relevant technology option, EPA found all the datasets passed the LTA test except for arsenic and mercury data at Wabash River. Thus, EPA excluded data for arsenic and mercury at Wabash River from the calculation of the long-term average, variability factors, and limitations. See the memorandum entitled "Effluent Limitations for FGD Wastewater, Gasification Wastewater, and Combustion Residual Leachate for the Final Effluent Limitations Guidelines and Standards for the Steam Electric Rulemaking" for the results of the LTA test for each pollutant at each plant [U.S. EPA, 2015b].

13.5 Overview Of Limitations

The preceding sections discussed the data selection, data exclusions and substitutions, data aggregation, as well as the data editing procedures that EPA used to identify the daily values for its limitations calculations. This section describes EPA's objectives for the daily maximum and monthly average effluent limitations, the selection of percentiles for those limitations, and compliance with the limitations.

13.5.1 Objectives

EPA's objective in establishing daily maximum limitations is to restrict discharges on a daily basis at a level that is achievable for a plant that targets its treatment at the long-term average.[148] EPA recognizes that variability around the long-term average occurs during normal operations, which means that plants might, at times, discharge at a level that is higher (or lower) than the long-term average. To allow for these occasional discharges that are at a higher concentration than the long-term average, EPA establishes a daily maximum limitation. A plant that consistently discharges at a level near the daily maximum limitation would not be operating its treatment system to achieve the long-term average. Targeting treatment to achieve the daily maximum limitations, rather than the long-term average, might result in values that frequently exceed the limitations due to routine variability in treated effluent.

EPA's objective in establishing monthly average limitations is to provide an additional restriction to help ensure that plants target their average discharges to achieve the long-term average. The monthly average limitation requires dischargers to provide ongoing control, on a monthly basis, that supplements controls to achieve the daily maximum limitation. To meet the monthly average limitation, a plant must counterbalance a value near the daily maximum limitation with one or more values well below the daily maximum limitation. For the plant to achieve compliance, these values must result in a monthly average value that is equal to or below the monthly average limitation.

13.5.2 Selection of Percentiles

EPA calculates effluent limitations based upon percentiles that should be both high enough to accommodate reasonably anticipated variability within control of the plant, and low

[148] Put simply, the long-term average is the average concentration that is achieved over a period of time. Statistically, the long-term average is the mean of the underlying statistical distribution of the daily effluent values. The long-term average is used along with other information about the distribution of the effluent data to calculate the effluent limitations.

enough to reflect a level of performance consistent with the CWA requirement that these effluent limitations be based on the best available technology or best available demonstrated control technology. The daily maximum limitation is an estimate of the 99th percentile of the distribution of the *daily* measurements. The monthly average limitation is an estimate of the 95th percentile of the distribution of the *monthly* averages of the daily measurements.

EPA uses the 99th and 95th percentiles to draw a line at a definite point in the statistical distributions that would ensure that plant operators work to establish and maintain the appropriate level of control. These percentiles reflect a longstanding Agency policy judgment about where to draw the line. The development of the limitations takes into account the reasonably anticipated variability in discharges that may occur at a well-operated plant. By targeting its treatment at the long-term average, a well-operated plant will be able to comply with the effluent limitations at all times because EPA has incorporated an appropriate allowance for variability in the limitations.

EPA's methodology for establishing effluent limitations based on certain percentiles of the statistical distributions may give the impression that EPA expects occasional exceedances of the limitations. This conclusion is incorrect. EPA promulgates limitations that plants are capable of complying with at all times by properly operating and maintaining their treatment technologies. These limitations are based upon statistical modeling of the data and engineering review of the limitations and data.

Statistical methodology is used as a framework to establish limitations based upon percentiles of the effluent data. Statistical methods provide a logical and consistent framework for analyzing a set of effluent data and determining values from the data that form a reasonable basis for effluent limitations. In conjunction with the statistical methods, EPA performs an engineering review to verify that the limitations are reasonable based upon the design and expected operation of the treatment technologies and the plant process conditions. As part of that review, EPA examines the range of performance reflected in the plant datasets used to calculate the limitations. The plant datasets represent operation of treatment technology that represents the best available technology or best available demonstrated control technology. In some cases, however, although these plants were operating model technology, these datasets, or periods of time within a dataset, may not necessarily represent the optimized performance of the technology. As described in Section 13.2, EPA excluded certain data from the datasets used to calculate the effluent limitations. At the same time, however, the datasets used to calculate effluent limitations still retain some observations that likely reflect periods of less than optimal performance. EPA retained these data in developing the limitations because they help to characterize the variability in treatment system effluent. Based on the combined statistical modeling and engineering review used to establish the limitations, plants are expected to design and operate their treatment systems in a manner that will ensure compliance with the limitations. EPA does not expect plants to operate their treatment systems so as to violate the limitations at some pre-set rate merely because probability models are used to develop limitations. See Section 13.9 for details of these comparisons for each pollutant at each plant, as well as a discussion of the findings of the engineering review.

13.5.3 Compliance with Limitations

EPA promulgates limitations with which plants are able to comply at all times by properly operating and maintaining their processes and treatment technologies. Public commenters often raise the issue of exceedances or excursions of limitations (i.e., values that exceed the limitations), and this rulemaking is no exception. For example, this issue was raised in EPA's rulemaking for the Organic Chemicals, Plastics, and Synthetic Fibers (OCPSF) manufacturing industry. EPA's general approach in that final rule to developing limitations based on percentiles is the same as in the final steam electric ELGs, and it was upheld in *Chemical Manufacturers Association v. U.S. Environmental Protection Agency*, 870 F.2d 177, 230 (5th Cir. 1989):

> "EPA reasonably concluded that the data points exceeding the 99th and 95th percentiles represent either quality-control problems or upsets because there can be no other explanation for these isolated and extremely high discharges. If these data points result from quality-control problems, the exceedances they represent are within the control of the plant. If, however, the data points represent exceedances beyond the control of the industry, the upset defense is available."

This issue was also raised in EPA's Phase I rule for the pulp and paper industry. In that rulemaking, EPA used the same general approach for developing limitations based on percentiles that it had used for the OCPSF rulemaking and for this final rule. EPA's approach for establishing the monthly average limitation was upheld in *National Wildlife Federation, et al. v. Environmental Protection Agency*, 286 F.3d 554, 573 (D.C. Cir. 2002):

> "EPA's approach to developing monthly limitations was reasonable. It established limitations based on percentiles achieved by plants using well-operated and controlled processes and treatment systems. It is therefore reasonable for EPA to conclude that measurements above the limitations are due to either upset conditions or deficiencies in process and treatment system maintenance and operation. EPA has included an affirmative defense that is available to mills that exceed limitations due to an unforeseen event. EPA reasonably concluded that other exceedances would be the result of design or operational deficiencies. EPA rejected Industry Petitioners' claim that facilities are expected to operate processes and treatment systems so as to violate the limitations at some pre-set rate. EPA explained that the statistical methodology was used as a framework to establish the limitations based on percentiles. These limitations were never intended to have the rigid probabilistic interpretation that Industry Petitioners have adopted. Therefore, we reject Industry Petitioners' challenge to the effluent limitations."

As the Court recognized, EPA's allowance for reasonably anticipated variability in its effluent limitations, coupled with the availability of the upset defense, reasonably accommodates acceptable excursions. Any further excursion allowances would go beyond the reasonable accommodation of variability and would jeopardize the effective control of pollutant discharges on a consistent basis. Further excursion allowances also could bog down administrative and enforcement proceedings in detailed fact-finding exercises, contrary to Congressional intent. See, for example, Rep. No. 92-414, 92d Congress, 2d Sess. 64, reprinted in A Legislative History of the Water Pollution Control Act Amendments of 1972 at 1482; Legislative History of the Clean Water Act of 1977 at 464-65.

More recently, for EPA's rule for the iron and steel industry, EPA's selection of percentiles was upheld in *American Coke and Coal Chemicals Institute v. Environmental Protection Agency,* 452 F.3d 930, 945 (D.C. Cir. 2006):

> "The court will not second-guess EPA's expertise with regard to what the maximum effluent limits represent. *See Nat'l Wildlife,* 286 F.3d at 571-73. As EPA explains in the Final Development Document, the daily and monthly average effluent limitations are not promulgated with the expectation that a plant will operate with an eye toward barely achieving the limitations. Final Development Document at § 14.6.2. Should a plant do so, it could be expected to exceed these limits frequently because of the foreseeable variation in treatment effectiveness. Rather, the effluent limitations are promulgated with the expectation that plants will be operated with an eye towards achieving the equivalent of the LTA for the BAT-1 model technology. *Id.* However, even operated with the goal of achieving the BAT-1 LTA, a plant's actual results will vary. EPA's maximum daily limitations are designed to be forgiving enough to cover the operations of a well-operated model facility 99% of the time, while its maximum monthly average limitations are designed to be forgiving enough to accommodate the operations of a well-operated model facility 95% of the time. *See id.* EPA's choice of percentile distribution represented by its maximum effluent limitation under the CWA represents an expert policy judgment that is not arbitrary or capricious. *See Nat'l Wildlife,* 286 F.3d at 573" (citation omitted).

EPA expects that plants will comply with promulgated limitations *at all times*. If an exceedance is caused by an upset condition, the plant would have an affirmative defense to an enforcement action if the requirements of 40 CFR 122.41(n) are met. Exceedances caused by a design or operational deficiency, however, are indications that the plant's performance does not represent the appropriate level of control. For the final steam electric ELGs, EPA determined that plants can control such exceedances by operating a properly designed treatment system that includes the necessary process equipment and chemical additives and that is sized to accommodate the wastewater flows, and by implementing process and wastewater treatment system operational practices such as regular monitoring of influent and effluent wastewater characteristics and adjusting dosage rates for chemical additives to target effluent performance for regulated pollutants at the long-term average concentration for the BAT/NSPS technology. A properly designed and operated treatment system includes characteristics such as periodic inspection and repair of equipment, use of appropriate redundant equipment such as backup pumps, sufficient staffing by trained operators, communications and coordination among production and wastewater treatment personnel, close attention to treatment system operating parameters and effluent quality, the ability to recognize and correct periods of degraded or abnormal operation, and equalization tanks to make wastewater flow and quality more uniform.

EPA recognizes that, as a result of the final rule, some plants may need to upgrade or replace existing treatment systems or improve their treatment systems, process controls, and/or treatment system operations to consistently meet the effluent limitations by targeting effluent concentrations at the long-term average. This is consistent with the CWA, which requires that discharge limitations and standards reflect the best available technology economically achievable or the best available demonstrated control technology, as well as EPA's costing approach and its engineering judgment developed over years of evaluating wastewater treatment processes at steam electric power plants and in other industrial sectors.

13.6 CALCULATION OF THE LIMITATIONS

EPA calculated the limitations by multiplying the long-term average by the appropriate variability factors. In deriving the limitations for a pollutant, EPA first calculates an average performance level (the "option long-term average" discussed below) that a plant with well-designed and well-operated model technology is capable of achieving. This long-term average is calculated using data from the model plant (plants with the model technologies) for the technology option.

In the second step of developing a limitation for a pollutant, EPA determines an allowance for the variation (the "option variability factor" discussed below) in pollutant concentrations for wastewater that has been processed through a well-designed and well-operated treatment system(s). This allowance for variation incorporates all components of potential variability, including sample collection, sample shipping and storage, and analytical variability. EPA incorporates this allowance into the limitations by using the variability factors that are calculated using data from the model plants. If a plant operates its treatment system to meet the relevant long-term average, EPA expects the plant will be able to meet the limitations. Variability factors provide an additional assurance that normal fluctuations in a plant's treatment process are appropriately accounted for in the limitations. By accounting for these reasonable excursions above the long-term average, EPA's use of variability factors results in effluent limitations that are above the long-term averages.

The following sections describe derivation of the option long-term averages, option variability factors and limitations, and the adjustment made for autocorrelation in the calculation of the limitations.

13.6.1 Calculation of Option Long-Term Average

EPA calculated the option long-term average for a pollutant using two steps. First, EPA calculated the plant-specific long-term average for each pollutant that had enough distinct detected values by fitting a statistical model to the daily concentration values. In cases when a dataset for a specific pollutant did not have enough distinct detected values to use the statistical model, the plant-specific long-term average for each pollutant was the arithmetic mean of the available daily concentration values. Appendix B presents an overview of the statistical model and describes the procedures EPA used to estimate the plant-specific long-term average.

Second, EPA calculated the option long-term average for a pollutant as the *median* of the plant-specific long-term averages for that pollutant. The median is the midpoint of the values when ordered (i.e., ranked) from smallest to largest. If there are an odd number of values, then the value of the m^{th} ordered observation is the median (where $m=(n+1)/2$ and n=number of values). If there are an even number of values, then the median is the average of the two values in the $n/2^{th}$ and $[(n/2)+1]^{th}$ positions among the ordered observations.

13.6.2 Calculation of Option Variability Factors and Limitations

The following describes the calculations performed to derive the option variability factors and limitations. First, EPA calculated the plant-specific variability factors for each pollutant that had enough distinct detected values by fitting a statistical model to the daily concentration values. Each plant-specific daily variability factor for each pollutant is the estimated 99th percentile of the distribution of the daily concentration values divided by the plant-specific long-term average. Each plant-specific monthly variability factor for each pollutant is the estimated 95th percentile of the distribution of the 4-day average concentration values divided by the plant-specific long-term average. The calculation of the plant-specific monthly variability factor assumes that the monthly averages are based on the pollutant being monitored weekly (approximately four times each month). In cases when there were not enough distinct detected values for a specific pollutant at a specific plant, then the statistical model was not used to obtain the variability factors for that plant. In these cases, EPA excluded the data for the pollutant at the plant from the calculation of the option monthly variability factors. Appendix B describes the procedures used to estimate the plant-specific daily and monthly variability factors.

Second, EPA calculated the option daily variability factor for a pollutant as the *mean* of the plant-specific daily variability factors for that pollutant. Similarly, the option monthly variability factor was the mean of the plant-specific monthly variability factors for that pollutant.

Finally, EPA calculated the daily maximum limitations for each pollutant for each technology option by multiplying the option long-term average and option daily variability factors. The monthly average limitations for each pollutant for each technology option are the product of the option long-term average and option monthly variability factors.

13.6.3 Adjustment for Autocorrelation

Effluent concentrations that are collected over time may be autocorrelated. The data are positively autocorrelated when measurements taken at specific time intervals, such as one or two days apart, are more similar than measurements taken far apart in time. For example, positive autocorrelation would occur if the effluent concentrations were relatively high one day and were likely to remain high on the next and possibly succeeding days. Because the autocorrelated data affect the true variability of treatment performance, EPA typically adjusts the variance estimates for the autocorrelated data, when appropriate.

For this rulemaking, whenever there were sufficient data for a pollutant at a plant to evaluate the autocorrelation reliably, EPA estimated the autocorrelation and incorporated it into the calculation of the limitations. For a plant without enough data to reliably estimate the autocorrelation, when there was a correlation of a pollutant available from a similar technology and waste stream and the pollutant removal processes were similar, EPA transferred the autocorrelation estimates from that treatment technology. Otherwise, EPA set the autocorrelation to zero in calculating the limitations, because the Agency did not have sufficient data to reliably evaluate whether the data were autocorrelated or to determine whether a valid autocorrelation estimate could be transferred from a similar technology and waste stream. See the memorandum entitled "Serial Correlations for Steam Electric With and Without Adjustment for Baseline Values" for details of the statistical methods and procedures EPA used to determine the autocorrelation values [Westat, 2015]. The following paragraphs describe the instances where EPA was able to estimate autocorrelation and the assumptions made about the autocorrelation when there were too few observations to estimate the possible autocorrelation.

For the chemical precipitation treatment option for FGD wastewater (represented by the Hatfield's Ferry, Keystone, Miami Fort, and Pleasant Prairie plants), EPA was able to perform a statistical evaluation of the autocorrelation and obtain a reliable estimate of the autocorrelation because several years of data were available for these plants. Table 13-2 lists the autocorrelation values used in the limitations calculation for arsenic and mercury for the chemical precipitation option.

For the biological treatment technology for FGD wastewater (represented by the Allen and Belews Creek plants), EPA was able to perform a statistical evaluation of the autocorrelation and obtain a reliable estimate of the autocorrelation because several years of data were available for these plants. As a result of the evaluation, EPA incorporated adjustments for autocorrelation into the limitations for the biological treatment technology option. Table 13-2 lists the autocorrelation values EPA used in the limitations calculation for nitrate-nitrite as N and selenium. EPA transferred the arsenic and mercury limitations for the biological treatment technology option from the chemical precipitation technology option and therefore incorporated adjustments to reflect autocorrelation (see Section 13.7).

Table 13-2. Summary of Autocorrelation Values Used in Calculating the Limitations for Biological Treatment Technology Option for FGD Wastewater

Treatment Technology	Plants Representing the Treatment Technology	Pollutant	Baseline Substitution? [a]	Correlation Value Used for Limit Calculation
FGD biological treatment	Allen, Belews Creek	Selenium	No	0.69
			Yes	0.67
		Nitrate-nitrite as N [b]	No	0.69
			Yes	0.67
FGD chemical precipitation treatment	Hatfield's Ferry, Keystone, Miami Fort, Pleasant Prairie	Arsenic [c]	No	0.86
			Yes	
		Mercury [d]	No	0.89
			Yes	

a – As described in Section 13.2.2.

b – There were not enough detected values for nitrate-nitrite as N at Allen and Belews Creek, so EPA was not able to evaluate the autocorrelation. However, EPA transferred the autocorrelation from selenium since these two chemicals behave similarly in the biological treatment system.

c – EPA estimated the correlation using data from Hatfield's Ferry.

d – EPA estimated the correlation using data from Hatfield's Ferry, Miami Fort, and Pleasant Prairie.

For the vapor-compression evaporation treatment technology option for FGD wastewater (represented by the Brindisi plant), and for the vapor-compression evaporation treatment technology option for gasification wastewater (represented by the Polk and Wabash River plants), EPA was unable to evaluate and obtain a reliable estimate of the autocorrelation because there were too few observations available at the plants. Thus, for these plants, EPA set the autocorrelation to zero in calculating the limitations because the Agency did not have sufficient data to reliably evaluate the autocorrelation or a valid correlation estimate available that could be transferred from a similar technology and waste stream.

13.7 TRANSFERS OF THE LIMITATIONS

In some cases, there were no data available for a particular treatment technology option for a wastestream or EPA determined that the treatment provided by plants using the model technology did not fully reflect the performance achievable by operation of all components of the technology on which the option is based. In these cases, EPA "transferred" limitations for that particular technology option from limitations that were calculated using other reliable and relevant data. EPA has transferred limitations in other ELG rulemakings, including transferring limitations derived from data representing the use of the model technology in an entirely other industry. In these cases, transfer of limitations is appropriate where EPA can show that the technology is available to the industry, that the technology is transferable to the industry, and that the technology is capable of removing the increment required by the limitations. *Kennecott v. EPA*, 780 F.2d 445, 453 (4th Cir. 1985); *Reynolds Metals Co. v. EPA*, 760 F.2d 549, 561-2 (4th Cir. 1985).

The following sections describe the two cases in which the limitations in this rulemaking were transferred: (1) the final new source performance standards (NSPS) applicable to combustion residual leachate (based on chemical precipitation), which were transferred from limitations derived using data representing treatment of FGD wastewater via chemical precipitation and (2) for two out of four pollutants, the final BAT limitations and pretreatment standards for existing sources (PSES) applicable to FGD wastewater (based on biological treatment), which were also transferred from limitations derived using data representing treatment of FGD wastewater via chemical precipitation.

13.7.1 Transfer of Arsenic and Mercury Limitations for Chemical Precipitation to Combustion Residual Leachate

The final rule establishes NSPS for combustion residual leachate based on the chemical precipitation technology option. EPA transferred the effluent limitations for combustion residual leachate based on the chemical precipitation technology option from the limitations calculated for FGD wastewater based on the chemical precipitation technology option because EPA does not have effluent data for combustion residual leachate treated by technology that represents the chemical precipitation technology option.

EPA determined that transfer of the limitations in this case was appropriate because the chemical precipitation treatment technology is available to the industry, it can be applied to combustion residual leachate in the industry, and it can achieve the pollutant removals necessary to meet the final limitations. Based on responses to the *Questionnaire for the Steam Electric*

Power Generating Effluent Guidelines, 39 steam electric power plants use some form of chemical precipitation as part of their FGD wastewater treatment system.[149] As described earlier, four steam electric power plants use a form of chemical precipitation to treat FGD wastewater that represents the chemical precipitation technology option. In addition, a wide range of industrial plants nationwide, such as metal products and machinery plants, iron & steel manufacturers, metal finishers, and mining operations (including coal mines), have demonstrated the use of chemical precipitation technology to remove arsenic and mercury [U.S. EPA, 1983; U.S. EPA, 2002; U.S. EPA, 2003].

Transferring limitations derived using data representing treatment of FGD wastewater via chemical precipitation technology to combustion residual leachate is appropriate because FGD wastewater and combustion residual leachate are both associated with combustion wastes and contain similar pollutants. EPA identified both arsenic and mercury as pollutants of concern for each wastestream (see Section 6.6 of the TDD). As such, both mercury and arsenic are present in untreated FGD wastewater and untreated combustion residual leachate at treatable levels.

The data evaluated for this rulemaking and published literature demonstrate that chemical precipitation can effectively remove arsenic and mercury from wastewater, and the precipitation (hydroxide and sulfide) and iron co-precipitation processes that make up the chemical precipitation technology basis are particularly effective. EPA received no data from stakeholders showing otherwise. Although arsenic and mercury are, on average, present in untreated combustion residual leachate at a lower concentration than in FGD wastewater, they are still present at treatable concentrations and are within the range of concentrations observed in untreated FGD wastewater for the plant datasets that EPA used to calculate the limitations for the chemical precipitation technology option for FGD wastewater. Therefore, EPA concludes that chemical precipitation is capable of removing arsenic and mercury from combustion residual leachate to the level necessary to achieve the final effluent limitations.

13.7.2 Transfer of Arsenic and Mercury Limitations for Chemical Precipitation to Biological Treatment for FGD Wastewater

The final rule establishes BAT limitations and PSES applicable to FGD wastewater based on the biological treatment technology option. EPA transferred the FGD wastewater effluent limitations for arsenic and mercury calculated for the chemical precipitation technology option to the biological treatment technology option because EPA determined that certain data from the model plants using biological treatment were, in some respects, not representative of a well-operated biological treatment system, as defined for this rule. This transfer of limitations for arsenic and mercury is appropriate because data from the steam electric power plants representing the chemical precipitation technology option better reflect the effluent concentrations that would be attained by the biological treatment technology when it uses all features in the technology option that remove arsenic, mercury, and many other metals from the wastewater. The technology upon which the biological treatment option is based comprises all elements of the chemical precipitation technology option followed by anoxic/anaerobic treatment and includes the following: equalization of the influent wastewater; chemical precipitation/co-

[149] Some plants operate a chemical precipitation treatment system in conjunction with other more advanced wastewater treatment such as biological treatment or evaporation.

precipitation to precipitate and remove both dissolved and particulate forms of the targeted pollutants (including pH adjustment, hydroxide precipitation, iron co-precipitation, sulfide precipitation, and clarification/filtration); and anoxic/anaerobic biological treatment to remove nitrogen (i.e., nitrate-nitrite as N) and both soluble and insoluble forms of selenium. All of these treatment steps contribute to the arsenic and mercury removals achieved by the biological treatment. As such, plants using this technology basis would remove pollutants to the same degree as plants using the chemical precipitation technology, plus any additional pollutant removals achieved by the biological treatment stage. The data for the biological treatment technology demonstrates that it is also effectively removes mercury from FGD wastewater, as much as 90 percent of the mercury entering the bioreactor. The biological treatment stage also further removes other pollutants, including arsenic.

EPA evaluated what the limitations for arsenic and mercury would be if they were based on data from the two plants using anoxic/anaerobic biological treatment: Allen and Belews Creek. Both of these plants have installed all equipment associated with the model chemical precipitation and biological treatment technologies; however, while both plants have the capability to add organosulfide chemicals to achieve sulfide precipitation of dissolved mercury and other pollutants in the chemical precipitation stage preceding the bioreactors, neither plant was actually dosing the organosulfide chemical when the data were collected. As a result, the arsenic and mercury effluent data for these plants do not reflect the additional pollutant removals that sulfide precipitation can achieve, nor do they reflect a well-operated chemical precipitation system or biological treatment system as defined for the technology options. Although some plants might meet their NPDES permit limitations using hydroxide precipitation alone, plants striving to maximize removals of mercury and other metals also use sulfide addition (e.g., organosulfide) as part of the process.

As is well documented in texts and papers on wastewater treatment, adding sulfide chemicals in addition to the alkali provides even greater removals of certain metals due to the very low solubility of metal sulfide compounds, relative to metal hydroxides [Palmer et al., 1988]. For this reason, EPA included the use of hydroxide precipitation, sulfide precipitation, and iron co-precipitation in the technology basis for both the chemical precipitation technology and the biological treatment technology options. Thus, although both Allen and Belews Creek have the technology in place, because neither was actually adding organosulfide, they were not optimizing the pollutant removal efficacy of their treatment systems for mercury or arsenic. Therefore, the treatment systems at these plants were susceptible to fluctuations in concentrations of dissolved metals, especially mercury, in the FGD wastewater. When the technology is operated without adding the chemicals for sulfide precipitation, it can be overwhelmed by excessively high influent concentrations of dissolved mercury. Since the chemical precipitation treatment stage is less effective at removing dissolved mercury when sulfide precipitation is not used, failing to add organosulfide in that stage can allow higher concentrations of dissolved mercury and other pollutants to pass through to the biological treatment stage. Even though the data evaluated for the ELGs show that the biological treatment stage can effectively remove a substantial portion of the mercury entering the bioreactor, the overall effluent concentration will be elevated if the treatment system does not incorporate adequate pretreatment, including sulfide precipitation, in the chemical precipitation stage.[150] EPA's analysis of the performance data for Allen and Belews Creek shows that these plants are not adequately treating dissolved mercury, which is attributable to the plants not adding organosulfide. In contrast, the model plants identified as using the technology that forms the basis for the chemical precipitation technology option are all adding organosulfide chemicals and operating the other key components for the chemical treatment stage for the biological treatment technology. EPA determined that the data used for chemical precipitation limitations better reflect the treatment efficacy for mercury and arsenic (and many other metals) for treatment systems using chemical precipitation/co-precipitation with both hydroxide and sulfide precipitation.

As a result, the final rule establishes BAT effluent limitations and PSES for arsenic and mercury in FGD wastewater (based on biological treatment) by transferring the limitations calculated for the chemical precipitation treatment technology option. EPA notes that it is reasonable to expect plants using the biological treatment technology to actually achieve even better effluent performance, since the biological treatment stage will remove additional arsenic and mercury following the chemical precipitation upon which the arsenic and mercury limitations are based.

13.8 Summary of the Limitations

Section 13.8.1 summarizes the plant-specific long-term averages, daily variability factors, and monthly variability factors for each pollutant in each treatment technology option, as calculated for each plant both with and without the baseline substitution described in Section 13.2.2. (Section 13.6 describes how EPA uses the plant-specific long-term averages and variability factors to derive the long-term average and variability factors for the technology option.) Section 13.8.2 summarizes the long-term average and variability factors calculated for each pollutant for each of the treatment technology options, as calculated both with and without baseline substitution. Section 13.8.2 also presents what the effluent limitations would be for each of those scenarios and technology options. Section 13.8.3 summarizes the effluent limitations established for FGD wastewater, gasification wastewater, and combustion residual leachate.

13.8.1 Summary of the Plant-Specific Long-Term Average and Variability Factors for Each Treatment Technology Option for FGD and Gasification Wastewaters

The plant-specific long-term average and variability factors for each pollutant for each treatment technology option for FGD and gasification wastewaters are presented below. The document entitled *Sampling Data Used as the Basis for Effluent Limitations for the Steam*

[150] The bioreactor removes mercury from the wastewater by both chemical and physical processes. The carbon bed in the bioreactors filters out particulate mercury (and other pollutants) that are transferred to the biological stage from the chemical precipitation stage. Additionally, the reduction processes in the bioreactors create sulfide compounds, which react with mercury and other pollutants to form metal sulfide compounds that precipitate as solids and are captured by the carbon bed. If, however, the treatment system has high concentrations of dissolved mercury in the influent, the sulfide production in the bioreactors may not be sufficient for creating and removing metal sulfide compounds to the extent necessary to meet the effluent limitations. For that reason, it is important for the chemical precipitation stage to include organosulfide addition (where chemical dosages can be readily adjusted as necessary to accommodate influent concentrations) and enable the majority of sulfide precipitation to occur prior to sending the wastewater to the bioreactors.

Electric Rulemaking lists of the data that EPA used to calculate the plant-specific results for each of the technology options [U.S. EPA, 2015a].

Chemical Precipitation Treatment Technology Option for FGD Wastewater

Table 13-3 presents the plant-specific results (i.e., long-term averages and variability factors) for the chemical precipitation technology option for FGD wastewater. The pollutants identified for regulation under this technology option are arsenic and mercury.

Table 13-3. Plant-Specific Results for the Chemical Precipitation Technology Option for FGD Wastewater

Pollutant	Plant Name	Baseline [a]	Plant-Specific Long-Term Average	Plant-Specific Daily Variability Factor	Plant-Specific Monthly Variability Factor
Arsenic (µg/L)	Hatfield's Ferry	0 or 2	9.135	2.098	1.412
	Keystone	0	3.064	1.632	1.431
		2	3.096	1.615	1.383
	Miami Fort	0 or 2	4.298	1.211	1.092
	Pleasant Prairie	0 or 2	7.655	2.101	1.410
Mercury (ng/L)	Hatfield's Ferry	0 or 0.5	118.683	5.321	2.352
	Keystone	0 or 0.5	66.878	3.642	1.907
	Miami Fort	0 or 0.5	200.007	7.044	2.732
	Pleasant Prairie	0 or 0.5	214.609	3.752	1.943

a – Where EPA identifies the baseline as zero, this means that the limitations are not based on the baseline substitution approach. Where the resulting value is the same with and without baseline substitution, this means that EPA obtained the same result in both cases.

Biological Treatment Technology Option for FGD Wastewater

Table 13-4 presents the plant-specific results (i.e., long-term averages and variability factors) for biological treatment for nitrate-nitrite as N and selenium as the technology basis for FGD wastewater. The pollutants identified for regulation under this technology option are arsenic, mercury, nitrate-nitrite as N, and selenium. As explained in Section 13.7.2, EPA transferred the limitations for arsenic and mercury for the biological treatment technology option from the chemical precipitation treatment technology option. Therefore, the values shown in Table 13-3 for arsenic and mercury also apply for limitations based on the biological treatment technology option.

Table 13-4. Plant-Specific Results for the Biological Treatment Technology Option for FGD Wastewater

Pollutant	Plant Name	Baseline [a]	Plant-Specific Long-Term Average	Plant-Specific Daily Variability Factor	Plant-Specific Monthly Variability Factor
Arsenic (µg/L) [b]	--	--	--	--	--
Mercury (ng/L) [b]	--	--	--	--	--
Nitrate-nitrite as N (mg/L)	Allen	0	2.549	16.876	3.841
	Belews Creek		0.035	9.360	2.892
	Allen	0.05	2.531	16.779	3.846
	Belews Creek		0.063	2.402	1.454
Selenium (µg/L)	Allen	0	7.134	3.283	1.589
	Belews Creek		7.923	2.779	1.480
	Allen	5	7.391	2.873	1.492
	Belews Creek		8.013	2.618	1.442

a – Where EPA identifies the baseline as zero, this means that the limitations are not based on the baseline substitution approach. Where the resulting value is the same with and without baseline substitution, this means that EPA obtained the same result in both cases.

b – Option long-term average and variability factors were transferred from chemical precipitation technology option for FGD wastewater.

Vapor-Compression Evaporation Treatment Technology Option for FGD Wastewater

EPA based the limitations for the vapor-compression evaporation technology option on the effluent data at Brindisi. The treatment system for the Brindisi power plant produces two effluent streams: (1) brine concentrator distillate; and (2) crystallizer condensate. Both of these streams are essentially the condensed steam from different stages of the evaporation process. The Brindisi plant ultimately recombines these streams in a distillate tank and then reuses them. However, it is possible that a plant may choose to reuse both streams (either in the FGD process or another plant process), discharge both streams, or reuse one stream while discharging the other to surface water. The effluent quality for the brine concentrator distillate and the crystallizer condensate are not identical. EPA anticipates that plants using this treatment technology will often combine the two effluent streams from the evaporator. EPA considered establishing a single set of effluent limitations based on the two effluent streams being combined prior to discharge or reuse; however, there is sufficient uncertainty about the flow rates for each of the streams at the time sampling data were collected that preclude establishing a combined limitation. EPA also considered establishing two sets of effluent limitations, one for each effluent stream. Although technically feasible, this approach would require plants to collect and analyze separate samples for each effluent stream. EPA determined that establishing separate limitations for the effluent streams is unnecessarily burdensome and is not necessary to ensure the FGD wastewater is being treated to the effluent quality achievable by operation of the evaporation technology. Thus, EPA established a single set of effluent limitations that applies to all FGD wastewater prior to discharge (whether as a single stream, combined stream, or multiple streams) and concluded this single set of effluent limitations is sufficient to ensure the appropriate level of control would be achieved. Because the effluent quality of the two wastestreams is not identical, EPA established the limitations based on the stream with the higher pollutant concentrations: crystallizer condensate. Setting the limitations on the higher concentration stream is necessary to ensure plants operating a well-designed and well-operated evaporation system can meet the limitations, regardless of whether they sample the effluent streams separately or as a combined stream. See the memorandum entitled "Effluent Limitations for FGD Wastewater, Gasification Wastewater, and Combustion Residual Leachate for the Final Effluent Limitations Guidelines and Standards for the Steam Electric Rulemaking" for the limitations that were calculated for each of the effluent streams discussed above [U.S. EPA, 2015b].

Table 13-5 presents the plant-specific results (i.e., long-term averages and variability factors) for the vapor-compression evaporation treatment technology option for FGD wastewater. The pollutants identified for regulation under this technology option are arsenic, mercury, selenium, and TDS.

Table 13-5. Plant-Specific Results for the Vapor-Compression Evaporation Technology Option (Crystallizer Condensate) for FGD Wastewater

Pollutant	Plant Name	Baseline [a]	Plant-Specific Long-Term Average	Plant-Specific Daily Variability Factor	Plant-Specific Monthly Variability Factor
Arsenic (µg/L)	Brindisi	0 or 2	4.0 [b]	-- [c]	-- [c]
Mercury (ng/L)	Brindisi	0 or 0.5	17.788	2.192	1.338
Selenium (µg/L)	Brindisi	0	4.0 [a]	-- [c]	-- [c]
		5	5.0 [a]	-- [c]	-- [c]
TDS (mg/L)	Brindisi	0 or 10	14.884	3.341	1.572

a – Where EPA identifies the baseline as zero, this means that the limitations are not based on the baseline substitution approach. Where the resulting value is the same with and without baseline substitution, this means that EPA obtained the same result in both cases.

b – Long-term average is the arithmetic mean since all observations were non-detected.

c – All observations were non-detected, so EPA could not calculate variability factors.

Vapor-Compression Evaporation Treatment Technology Option for Gasification Wastewater

In developing the limitations for this technology option, EPA calculated the limitations using the gasification wastewater data from Wabash River and Polk. The treatment system at Wabash River produces one treated effluent stream: condensate from vapor compression evaporator. The treatment system for Polk Power Station produces two treated wastewater streams: (1) condensate from the vapor compression evaporator; and (2) condensate from the forced circulation evaporator. Both of these streams at Polk are essentially the condensed steam from different stages of the evaporation process. Because it is possible that a plant may choose to reuse both streams, discharge both streams, or reuse one stream while discharging the other to surface water, EPA considered data from the following effluent streams when developing the limitations for this technology option: (i) forced circulation evaporator condensate effluent (based only on Polk); and (ii) vapor compression evaporator effluent (based on Polk and Wabash River). However, EPA determined that the data collected at forced circulation evaporator condensate did not demonstrate typical removal rates for pollutants generally well treated by evaporation and therefore were not appropriate for use in calculating limitations. Based on its review of the data for the treatment system, EPA determined that the evaporator (or at a minimum the forced circulation evaporation stage) was operating abnormally and allowing carryover of pollutants to the condensate effluent stream. For this reason, EPA based the limitations for this technology option on effluent data for the vapor compression evaporators at Polk and Wabash River.

Table 13-6 presents the plant-specific results (i.e., long-term averages and variability factors) for vapor-compression evaporation treatment as the technology basis for gasification wastewater. The pollutants identified for regulation under this technology option are arsenic, mercury, selenium, and TDS. As explained in Section 13.4, the data for arsenic and mercury at Wabash River failed the data editing criteria; therefore, EPA excluded the arsenic and mercury datasets from Wabash River when calculating the limitations for this technology option.

Table 13-6. Plant-Specific Results for the Vapor-Compression Evaporation Technology Option (Vapor-Compression Evaporator Condensate) for Gasification Wastewater

Pollutant	Plant Name	Baseline [a]	Plant-Specific Long-Term Average	Plant-Specific Daily Variability Factor	Plant-Specific Monthly Variability Factor
Arsenic (µg/L)	Polk	0 or 2	4.00 [b]	-- [c]	-- [c]
	Wabash River	0 [d]	4.00 [b]	-- [c]	-- [c]
Mercury (ng/L)	Polk	0 or 0.5	1.075	1.632	1.194
Selenium (µg/L)	Polk	0 or 5	288.434	3.083	1.545
	Wabash River	0	4.534	1.360	1.116
		5	5.125	-- [c]	-- [c]
TDS (mg/L)	Polk	0 or 10	16.512	2.149	1.327
	Wabash River	0 or 10	13.906	2.818	1.450

a – Where EPA identifies the baseline as zero, this means that the limitations are not based on the baseline substitution approach. Where the resulting value is the same with and without baseline substitution, this means that EPA obtained the same result in both cases.

b – Long-term average is the arithmetic mean since there are too few detected observations.

c – Nearly all observations were non-detected, so EPA could not calculate variability factors.

d – After baseline adjustment, EPA excluded the Wabash River arsenic data because it did not pass the LTA test

13.8.2 <u>Summary of the Option-Level Long-Term Averages, Variability Factors, and Limitations for Each Treatment Technology Option for FGD, Gasification, and Combustion Residual Leachate Wastewaters</u>

This section presents the option-level long-term average and variability factors for each pollutant in each of the treatment technology options for FGD, gasification, and combustion residual leachate wastewaters. In addition, this section presents what the limitations would be for each of the technology options, as calculated with and without baseline substitution. EPA obtained these results by combining the plant-specific results for each technology option presented in Section 13.8.1 (except for combustion residual leachate wastewater because the limitations for that wastestream were transferred from the chemical precipitation technology option for FGD wastewater). As described in Section 13.6, the option-level long-term average for each pollutant is the median of the plant-specific long-term averages. The option-level variability factor for each pollutant is the mean of the plant-specific variability factors. The daily limitation for each pollutant is the product of the option long-term average and option daily variability factor. The monthly average limitation for each pollutant is the product of the option long-term average and option monthly variability factor.

The limitations for FGD wastewater based on chemical precipitation followed by vapor-compression evaporation and the arsenic limitations for gasification wastewater based on vapor-compression are each based on data from one plant. As such, the option-level long-term averages and variability factors for these options are the same as the plant-specific long-term averages and variability factors. Also, in cases where there are too few detected results, the statistical models are not appropriate for calculating limitations since reliable estimates could not be obtained from the models. In such instances, EPA has established the daily maximum limitations based on the detection limit (i.e., "minimum level").[151] Also, EPA is not establishing monthly average limitations when the daily maximum limitation is based on the detection limit since no appropriate model could be used.

Table 13-7 provides the option-level long-term average, variability factors, and limitations for each of the FGD, gasification, and combustion residual leachate technology options, as calculated both with and without baseline adjustment.

Table 13-7. Option-Level Long-Term Averages, Variability Factors, and Limitations for Each of the FGD, Gasification, and Combustion Residual Leachate Technology Options with or without baseline Adjustment

Treatment Technology Option	Pollutant	Baseline	Option Long-Term Average	Option Daily Variability Factor	Option Monthly Variability Factor	Daily Maximum Limitation [a]	Monthly Average Limitation [a]
Chemical Precipitation for FGD Wastewater	Arsenic (µg/L)	0	5.976	1.760	1.336	11	8
		2	5.976	1.756	1.324	11	8
	Mercury (ng/L)	0 or 0.5	159.345	4.940	2.233	788	356
Chemical Precipitation and Biological Treatment for FGD Wastewater	Arsenic (µg/L) [b]	0	5.976	1.760	1.336	11	8
		2	5.976	1.756	1.324	11	8
	Mercury (ng/L) [b]	0 or 0.5	159.345	4.940	2.233	788	356
	Nitrate-nitrite as N (mg/L)	0	1.292	13.118	3.366	17.0	4.4
		0.05	1.297	9.590	2.650	12.5	3.5
		0	7.528	3.031	1.535	23	12

[151] As used in this section of this document, "detection limit" refers to the quantitation limit (QL) and not the method detection limit (MDL). Thus, effluent limitations in those instances would be established as a daily maximum limit at the quantitation limit.

Table 13-7. Option-Level Long-Term Averages, Variability Factors, and Limitations for Each of the FGD, Gasification, and Combustion Residual Leachate Technology Options with or without baseline Adjustment

Treatment Technology Option	Pollutant	Baseline	Option Long-Term Average	Option Daily Variability Factor	Option Monthly Variability Factor	Daily Maximum Limitation [a]	Monthly Average Limitation [a]
	Selenium (µg/L)	5	7.702	2.746	1.467	22	12
Chemical Precipitation and Evaporation for FGD Wastewater	Arsenic (µg/L)	0 or 2	4.0 [c]	-- [d]	-- [d]	4 [e]	-- [f]
	Mercury (ng/L)	0 or 0.5	17.788	2.192	1.338	39	24
	Selenium (µg/L)	0	4.0 [c]	-- [d]	-- [d]	4 [e]	-- [f]
		5	5.0 [c]	-- [d]	-- [d]	5 [e]	-- [f]
	TDS (mg/L)	0 or 10	14.884	3.341	1.572	50	24
Vapor-Compression Evaporation for Gasification Wastewater	Arsenic (µg/L)	0 or 2	4.0 [c]	-- [d]	-- [d]	4 [e]	-- [f]
	Mercury (ng/L)	0 or 0.5	1.075	1.632	1.194	1.8	1.3
	Selenium (µg/L)	0	146.484	2.222	1.331	326	195
		5	146.780	3.083	1.545	453	227
	TDS (mg/L)	0 or 10	15.209	2.483	1.389	38	22
Chemical Precipitation for Combustion Residual Leachate Wastewater	Arsenic (µg/L) [b]	0	5.976	1.760	1.336	11	8
		2	5.976	1.756	1.324	11	8
	Mercury (ng/L) [b]	0 or 0.5	159.345	4.940	2.233	788	356

a – Limitations greater than 1.0 have been rounded upward to the next highest integer, except for limitations for mercury based on the vapor-compression evaporation treatment technology option for gasification wastewater and limitations for nitrate-nitrite as N for FGD wastewater, which have been rounded up to the next highest tenth decimal place.

b – EPA transferred option long-term averages, variability factors, and limitations from the chemical precipitation technology option for FGD wastewater.

c – Long-term average is the arithmetic mean since all observations were non-detected.

d – All observations were non-detected, so EPA could not calculate variability factors.

e – Limitation is set equal to the detection limit.

f – EPA is not establishing monthly average limitations when the daily maximum limitation is based on the detection limit.

13.8.3 Long-Term Averages and Effluent Limitations for FGD Wastewater, Gasification Wastewater, and Combustion Residual Leachate

Table 13-8 and Table 13-9 present the effluent limitations and standards for discharges of FGD wastewater, gasification wastewater, and combustion residual leachate from existing and new sources in the final rule. As described in Section 13.2, EPA evaluated what the limitations would be using baseline substitution, as well as what the limitations would be without adjusting for baseline substitution. The limitations established for the rule use the higher result.

Table 13-8 and Table 13-9 also present the long-term average treatment performance calculated for the selected treatment technology option. Due to routine variability in treated effluent, a power plant that targets its treatment to achieve pollutant concentrations at a level near the values of the daily maximum limitation or the monthly average limitation may experience frequent values exceeding the limitations. For this reason, EPA recommends that plants design and operate the treatment system to achieve the long-term average for the model technology. In doing so, a system that is designed to represent the BAT/NSPS level of control would be expected to meet the limitations.

Table 13-8. Long-Term Averages and Effluent Limitations and Standards for FGD Wastewater and Gasification Wastewater for Existing Sources

Wastestream	Pollutant	Long-Term Average	Daily Maximum Limitation	Monthly Average Limitation
FGD Wastewater (BAT & PSES)	Arsenic (µg/L)	5.98	11	8
	Mercury (ng/L)	159	788	356
	Nitrate/nitrite as N (mg/L)	1.3	17.0	4.4
	Selenium (µg/L)	7.5	23	12
Voluntary Incentives Program for FGD Wastewater (BAT only)	Arsenic (µg/L)	4.0 [a]	4 [b]	--- [c]
	Mercury (ng/L)	17.8	39	24
	Selenium (µg/L)	5.0 [a]	5 [b]	--- [c]
	TDS (mg/L)	14.9	50	24
Gasification Wastewater (BAT & PSES)	Arsenic (µg/L)	4.0 [a]	4 [b]	--- [c]
	Mercury (ng/L)	1.08	1.8	1.3
	Selenium (µg/L)	147	453	227
	TDS (mg/L)	15.2	38	22

a – Long-term average is the arithmetic mean of the quantitation limitations since all observations were not detected.

b – Limitation is set equal to the quantitation limit.

c – EPA is not establishing monthly average limitation when the daily maximum limitation is based on the quantitation limit.

Table 13-9. Long-Term Averages and Standards for FGD Wastewater, Gasification Wastewater, and Combustion Residual Leachate for New Sources

Wastestream	Pollutant	Long-Term Average	Daily Maximum Limitation	Monthly Average Limitation
FGD Wastewater (NSPS & PSNS)	Arsenic (µg/L)	4.0 [a]	4 [b]	--- [c]
	Mercury (ng/L)	17.8	39	24

Table 13-9. Long-Term Averages and Standards for FGD Wastewater, Gasification Wastewater, and Combustion Residual Leachate for New Sources

Wastestream	Pollutant	Long-Term Average	Daily Maximum Limitation	Monthly Average Limitation
	Selenium (µg/L)	5.0 [a]	5 [b]	--- [c]
	TDS (mg/L)	14.9	50	24
Gasification Wastewater (NSPS & PSNS)	Arsenic (µg/L)	4.0 [a]	4 [b]	--- [c]
	Mercury (ng/L)	1.08	1.8	1.3
	Selenium (µg/L)	147	453	227
	TDS (mg/L)	15.2	38	22
Combustion Residual Leachate (NSPS & PSNS)	Arsenic (µg/L) [d]	5.98	11	8
	Mercury (ng/L) [d]	159	788	356

a – Long-term average is the arithmetic mean of the quantitation limitations since all observations were not detected.

b – Limitation is set equal to the quantitation limit.

c – EPA is not establishing monthly average limitation when the daily maximum limitation is based on the quantitation limit.

d – EPA transferred long-term averages and standards from performance of chemical precipitation in treating FGD wastewater.

13.9 ENGINEERING REVIEW OF THE LIMITATIONS

Plants that install treatment technologies to comply with the newly promulgated limitations will need to design and operate the systems to meet the limitations at all times. In summary, this means:

1. A treatment system that includes the necessary process equipment and chemical additives that is sized to accommodate the wastewater flows and is designed to target removing the regulated pollutants to meet the long-term average.
2. Proper attention and operation that targets chemical addition rates and other operational conditions to the long-term average for the regulated pollutants, considers fluctuations in influent wastewater flows and pollutant concentrations, and proactively monitors for and responds to fluctuations in effluent pollutant concentrations due to abnormal conditions or treatment system upsets.

A properly designed and operated treatment system that represents best available technology or best available demonstrated control technology includes characteristics such as proper chemical usage, regular inspection and repair of equipment, use of backup systems, operator training and performance evaluations, management control, careful communications and coordination among production and wastewater treatment personnel, consistent monitoring and close attention to treatment system operating parameters and effluent quality, systems and processes that recognize and correct periods of degraded or abnormal operation, and equalization tanks to make wastewater flow and quality more uniform.

Proper design does not include improperly designed or inadequate treatment facilities (including systems targeted to meet the limitations rather than the long-term averages), such as treatment systems that lack sufficient equalization tank capacity to dampen fluctuations in wastewater flow rates or pollutant concentrations, nor does it include treatment systems that do not include key process equipment or chemical additives, such as the organosulfides used to enhance precipitation of dissolved mercury.

As part of its review of the final limitations, EPA often looks at the data from the model plants to see if the data demonstrate that they can comply with the final limitations. It is not unusual for EPA to find that one or all of the model plants may need to make treatment technology upgrades or improvements to their operation to comply with the final limitations. Typically, although most observations in the datasets used to calculate the effluent limitations are below the limitations, there are some observations above the limitations. It is reasonable for this situation to arise in datasets used to calculate limitations and there are specific steps that plants can take that would enable them to improve treatment system performance so that effluent concentrations would be in compliance with the limitations at all times. Although EPA selects model plants as representing the best available technology or best available demonstrated control technology, and they provide the best available data for establishing limitations that reflect BAT/NSPS level of treatment, it does not necessarily mean that the plants have their systems fully optimized. For example, the NPDES permit for a model plant may not include limitations for the regulated pollutant or the NPDES permit limitations may be well above the final limitations and what other systems are achieving. Thus, these plants would be expected to have data above the limitations (and that do not reflect BAT/NSPS level of control), not because the systems are incapable of achieving the limitations, but rather because the existing permit limitations do not drive the plants to optimize their pollutant removals. If EPA's review demonstrates that a model plant is not consistently achieving the final limitations, EPA looks at the treatment system design and operation for the model plant to determine if it currently meets EPA's expectations for proper design and operation.[152] In this way, EPA confirms that the final limitations are reasonable and will be achieved by properly designed and operated systems.

For this final rule, EPA performed an engineering review to verify that the effluent limitations are reasonable based upon the design and expected operation of the control technologies. As part of this review, EPA performed two types of comparisons. First, EPA compared the effluent limitations for each pollutant against the effluent data from the model plants used to develop the limitations. This type of comparison helps to evaluate how reasonable the limitations are from an engineering perspective. Second, EPA compared the limitations for each pollutant against the influent data at the model plants. This second comparison helps evaluate whether the influent concentrations were generally well controlled by the treatment system.

Section 13.9.1 presents the results of the comparisons between the limitations and all effluent data that were used to calculate the limitations for each technology option. Section 13.9.2 presents the results of the comparisons between the effluent limitations and the influent data values for each technology option. For the detailed results of these comparisons, see the memorandum entitled "Effluent Limitations for FGD Wastewater, Gasification Wastewater, and Combustion Residual Leachate for the Final Effluent Limitations Guidelines and Standards for the Steam Electric Rulemaking" [U.S. EPA, 2015a].

[152] If they do not, EPA includes costs for the model plants to do so.

13.9.1 Comparison of Limitations to Effluent Data Used As Basis for the Limitations

EPA first compared the daily effluent values to the daily limitations to identify any values above the daily limit. The plots that EPA prepared for this first comparison also provide insight into how other values (i.e., daily values below the daily limit) compare to the limit. EPA then compared the effluent daily values to the monthly average limitations, for those periods where there are sufficient data to represent weekly monitoring,[153] and identified those months where the average of all daily values for the month is above the monthly limit. As with the comparison to the daily limitations, the plots that EPA prepared also provide insight into how monthly averages below the monthly limitation compare to the limitation.

After thoroughly evaluating the results of the comparison between the limitations and the effluent values used to calculate the limitations (see details below), EPA determined that the statistical distributional assumptions used to develop the limitations are appropriate for the data (that is, they provide a reasonable "fit" to the actual effluent data) and the limitations for each wastestream are reasonable and achievable. (This conclusion is also true for the combustion residual leachate limitations based on the chemical precipitation technology since the combustion residual leachate limitations were transferred from the limitations derived for the chemical precipitation technology option for FGD wastewater.) If a plant properly designs and operates its wastewater treatment system to achieve the long-term average for the model technology (rather than targeting performance at the effluent limitations themselves), it will be able to comply with the limitations.

Although the comparison of the limitations to the effluent data identifies some values greater than the limitations in the data used to calculate the limitations, for the reasons described below, EPA concludes that all plants properly operating and maintaining the appropriate technology will be able to comply with the limitations.

In comparing the effluent data to the limitations, EPA noted there are instances where one or more daily values in a month are higher than the monthly limit, but the average of all results in a month are equal to or less than the monthly average limit. Instances such as these are normal and consistent with the way effluent limitations are calculated and implemented in NPDES permits. This is illustrated by Hatfield's Ferry's arsenic data for February 2010, as described below. EPA also identified some cases where only one sample was taken during a month and the resulting concentration value for that one sample is above the monthly limit. In

[153] This approach is consistent with the manner in which EPA calculated the limitations and anticipates plants will monitor for compliance with NPDES permits. It is also consistent with the monitoring frequency EPA has generally observed in NPDES permits, for those pollutants for which the permit includes effluent limitations. Additionally, it is consistent with EPA's methodology for estimating compliance costs for the final rule, which includes estimated operation and maintenance (O&M) costs for weekly compliance monitoring. Furthermore, it is a reasonable approach for conducting the engineering review because an assessment that uses data from less frequent monitoring may more closely reflect the daily variability than the monthly variability and therefore would not accurately reflect whether the monthly limit would have been met. For example, the four weekly samples collected from Hatfield's Ferry in February 2010 are all equal to or below the daily limit of 11 µg/L. One of these observations (11 µg/L) is higher than the monthly limit of 8 µg/L. However, the average of all daily values for the month is 7.5 µg/L, which is below the monthly limit.

such cases, additional monitoring of the effluent (e.g., at weekly intervals) would likely result in a monthly average that would fall below the monthly average limit.

Based on the results described in the sections below for the comparisons of effluent and influent data to the limitations, and information described elsewhere that was evaluated for the ELGs, EPA determined that the statistical distributional assumptions are appropriate for the effluent data and that the daily maximum and monthly average limitations for the rule are reasonable and achievable.

Arsenic and Mercury Limitations for FGD Wastewater, Based on Performance of Chemical Precipitation Technology

EPA calculated effluent limitations for arsenic and mercury in FGD wastewater based on the performance of chemical precipitation treatment technology. These limitations were transferred to the biological treatment technology option and thus form the bases for the arsenic and mercury limitations applicable to FGD wastewater in the final rule. The Agency calculated the limitations using data from four plants: Hatfield's Ferry, Keystone, Miami Fort, and Pleasant Prairie.

- *Arsenic – Comparison of effluent data to the daily maximum limit of 11 ug/L:*
  - All observations for two plants were equal to or below the daily maximum limit (24 observations at Keystone; nine observations at Miami Fort). At Pleasant Prairie, all but one of the 20 observations were equal to or below the daily limit. At Hatfield's Ferry, 102 observations were equal to or below the daily limit; 28 of the 130 total observations at Hatfield's Ferry were above the daily limit.
- *Arsenic – Comparison of effluent data to the monthly average limit of 8 ug/L:*
  - Only Keystone and Hatfield's Ferry collected effluent samples with sufficient frequency within a month to represent weekly sampling. For the time periods where there were sufficient data, EPA calculated the average of the daily values collected within a month and compared that average value to the monthly average limit. For Keystone, all such monthly average values were below the limit. In fact, every daily observation at Keystone was below the monthly limit. For Hatfield's Ferry, there were 12 months when the average value was equal to or below the limit; there were 15 months when the average value was above the monthly limit (most of those were 1-2 ug/L above the monthly limit). Although Miami Fort did not collect samples with sufficient frequency to calculate monthly averages, all of the daily observations for the plant were equal to or below the monthly limit and, therefore, EPA did not identify any periods of time when the effluent concentrations were higher than the limit.
- *Mercury – Comparison of effluent data to the daily maximum limit of 788 ng/L:*
  - All observations at Keystone and Miami Fort were below the daily maximum limit (eight observations at Keystone; 68 observations at Miami Fort). Of the 219 total observations at Hatfield's Ferry, 217 were below the daily limit and two were above the daily limit. Of the 375 total observations at Pleasant Prairie, 370

observations were below the daily limit and five were above the daily maximum limit.

- *Mercury – Comparison of effluent data to the monthly average limit of 356 ng/L:*
  - Only Hatfield's Ferry and Pleasant Prairie collected effluent samples with sufficient frequency within a month to represent weekly sampling. For the time periods where there were sufficient data, EPA calculated the average of the daily values collected within a month, and compared that average value to the monthly average limit. At Hatfield's Ferry, all but one of the monthly average values were below the limit (39 of the 40 monthly values). For Pleasant Prairie, there were 27 months when the average value was below the limit; there were 3 months when the average value was above the monthly limit. Although Keystone did not collect samples frequently enough to calculate monthly averages, all of the daily observations for the plant were equal to or below the monthly limit and, therefore, EPA did not identify any periods of time when the effluent concentrations were higher than the limit. Miami Fort also did not collect samples frequently enough to calculate monthly averages; however, it is worth noting that 61 of the 68 daily observations for the plant were below the monthly limit.

EPA determined that all power plants discharging FGD wastewater, including the plants discussed here, are capable of meeting the effluent limitations for arsenic and mercury. While there were certain instances where the model plants' effluent data concentrations are higher the final limitations, based on its engineering judgment developed over years of evaluating wastewater treatment processes for power plants and other industrial sectors, EPA determined that the combination of additional monitoring, closer operator attention, and optimizing treatment system performance to target the effluent concentrations at the technology option long-term averages will result in lower effluent concentrations that would comply with the effluent limitations.

Although most observations in the datasets used to calculate the effluent limitations were below the limitations, there were some observations above the limitations. As explained above, it is reasonable for this situation to arise in datasets used to calculate limitations for the rule, and there are specific steps that the plants can take to improve treatment system performance so that effluent concentrations would comply with the limitations at all times. Although EPA selected these plants as representing the best available technology and they provide the best available data for establishing arsenic and mercury effluent limitations that reflect BAT level of treatment for FGD wastewater, it does not necessarily mean that the plants' systems are fully optimized, especially since the NPDES permits for these plants either do not include limitations for arsenic or mercury in their discharges of FGD wastewater or because their NPDES permit limitations are well above what the system is capable of achieving.[154,155,156,157] This is supported by Duke Energy's comments on the proposed effluent guidelines, which state that the "performance of the chemical precipitation treatment systems from which EPA's data relies were optimized to meet current facility NPDES permit requirements and may not reflect the system's maximum performance."[158]

[154] Pleasant Prairie's NPDES permit (WI-0043583-06-1) FGD wastewater monitoring requirements include both in-plant requirements (Outfall 102, effluent from the FGD blowdown wastewater treatment system) and final outfall requirements (Outfall 001, combined discharge to Lake Michigan for five internal outfalls, including cooling tower blowdown and FGD wastewater). Outfall 102 includes no effluent limitations for arsenic (requiring only that the plant monitor for the pollutant monthly); mercury has a daily limit of 1,500 ng/L (monitored twice weekly), but no monthly limit. Outfall 001 includes a daily maximum limit for mercury (and a monitoring requirement but no effluent limit for arsenic), but the NPDES permits specifically states that "the FGD effluent may only discharge when sufficient flow from other wastewater streams (cooling tower blowdown, low volume wastewater, coal pile runoff, or metal cleaning waste basin) is available if necessary to comply with the water quality based effluent limitations at Outfall 001."

[155] Miami Fort's NPDES permit (OH0009873) FGD wastewater monitoring requirements include both in-plant requirements (Outfall 608, FGD wastewater treatment system discharge prior to the ash pond) and final outfall requirements (Outfall 002, ash pond discharge, including FGD wastewater, prior to the Ohio River). Outfall 608 includes no effluent limitations for arsenic or mercury, requiring only that the plant monitor the concentrations of these pollutants monthly. Outfall 002 similarly includes no effluent limitations for arsenic or mercury, requiring only that the plant monitor the concentrations of these pollutants quarterly.

[156] Hatfield's Ferry Power Station's NPDES permit (PA0002941) FGD wastewater monitoring requirements include both in-plant requirements (Outfall IMP 306, effluent from the FGD scrubber blowdown wastewater treatment plant) and final outfall requirements (Outfall 006, which includes ash transport water, coal pile runoff, low volume waste and FGD wastewater treatment system effluent). Outfall IMP 306 includes no effluent limit for arsenic, requiring only that the plant monitor for the pollutant weekly; the permit includes a mercury daily limit of 10,000 ng/L and a monthly average limit of 5,000 ng/L (monitored weekly). Outfall 006 includes no effluent limit or monitoring requirement for arsenic; the permit includes a mercury daily limit of 4,000 ng/L and a monthly average limit of 2,000 ng/L (monitored weekly).

[157] Keystone's NPDES permit (PA0002062) FGD wastewater monitoring requirements include both in-plant requirements (IMP 101, discharge from the FGD scrubber blowdown wastewater treatment plant) and final outfall requirements (Outfall 001, which includes discharges from the pipeline pigging wastewater treatment facility and FGD scrubber blowdown wastewater treatment plant). IMP 101 includes no effluent limit for arsenic, requiring only that the plant monitor for the pollutant weekly; the permit includes a mercury daily limit of 8,000 ng/L and a monthly average limit of 4,000 ng/L (monitored weekly). Outfall 001 includes similar effluent monitoring/limitations, with monitoring required only when pigging wastewater is discharged.

[158] Duke Energy's comments state that "[t]he operation and performance of chemical precipitation systems for FGD water treatment is continuing to evolve and improve. The industry's current chemical precipitation system performance data does not accurately reflect optimized performance…". "The performance of the chemical precipitation treatment systems from which EPA's data relies were optimized to meet current facility NPDES permit requirements and may not reflect the system's maximum performance. For example, operating these systems at higher pH levels can increase the percentage of metal removal. Improved treatment chemicals, improved clarification and filtration can further increase removal percentages. If necessary, modifications to chemical precipitation systems towards optimizing removal of specific constituents, not currently permitted, can result in more effective treatment of FGD wastewater." Duke Energy goes on to state that "Miami Fort has implemented several improvements to their chemical precipitation process to improve mercury removal. Increasing pH from initial startup settings, adding coagulants, and organosulfide metal precipitants have led in favorable results. Polymer delivery systems have been modified and the baffling inside the clarifier has also been changed to improve solids settling and reduce the Total Suspended Solids (TSS)." Comments of Duke Energy to the United States Environmental Protection Agency, p. 13. September 19, 2013.

The two plants that have observations above the limitations for arsenic do not have specific limitations in their NPDES permits for discharges of arsenic in FGD wastewater. Also, only three of the plants have NPDES permit limitations for mercury, and for two of these plants the permit limitations are more than 10 times higher than the BAT effluent limitations established by the final rule. For this reason, these plants currently do not need to closely monitor the concentrations of arsenic and mercury in the treatment system effluent or take steps to optimize the removal of these pollutants. This is illustrated by the plants' operational practices for their FGD wastewater treatment systems. Other than Pleasant Prairie targeting an effluent concentration that would allow discharges containing mercury at double the concentration established for the final rule, none of the plants reported having operational target parameters for the allowable level of mercury and arsenic in their effluent.[159,160,161]

As noted above, the NPDES permit for Hatfield's Ferry includes no arsenic limitations for the effluent from the FGD wastewater treatment system. The NPDES permit daily maximum limit for mercury is 10,000 ng/L (5,000 ng/L monthly limit). Additionally, the plant does not operate its treatment system to achieve any specific operational targets for arsenic or any other metal. Instead, the plant operates the treatment system to maintain pH within an operational range, ensure the clarifier indicates good settling of the precipitated floc, and provide adequate removal of TSS in the effluent from the sand filters. Because of this, it is reasonable to expect that the chemical addition rates for sodium hydroxide, organosulfide, and other additives are not optimized for arsenic removal. Pleasant Prairie's NPDES permit includes a daily maximum limit for mercury at 1,500 ng/L in the treatment system effluent, but no monthly limit. The plant's operational target of 1,000 ng/L mercury for the treatment system effluent is very near this permit limit. Given the high permit limit and operational target, it is not surprising that a small number of observations are above the limitations established by the rule.

Both plants could take steps to ensure compliance with the final limitations by making adjustments to the treatment system operation to target the long-term average performance that the effluent limitations are based upon (i.e., 5.98 ug/L for arsenic and 159 ng/L for mercury). Operator attention to effluent quality and process control indicators (e.g., wastewater flow rates, conductivity, clarifier bed levels, TSS) facilitate steady-state operation of the treatment system, as well as alerting operators of system abnormalities or fluctuations in influent quality or flow rate. EPA's review of chemical precipitation systems for this industry noted that plants could benefit from using an in-house mercury analyzer to monitor the performance of the system on a

[159] When asked about the operational target parameters for the treatment system, Pleasant Prairie personnel reported that they target achieving an effluent concentration below 1,000 ng/L in the effluent from the secondary clarifier. If the measured concentration is below 1,000 ng/L, discharge is continuous. If clarifier effluent concentration is in the range 1,000-1,500 ng/L, continuous discharge ceases and, depending on samples collected from the effluent tank, the wastewater is either discharged (if <1,500 ng/L) or recirculated for further processing (if >1,500 ng/L). If the clarifier effluent is above 1,500 ng/L, the wastewater is recirculated to the absorber or treatment system equalization tank for further processing. DCN SE04328

[160] When asked about the operational target parameters for the treatment system, Miami Fort personnel reported that they make day-to-day adjustments based on pH, turbidity, and TSS to make sure there is good settling and clarification. Depending on settling performance, they may adjust the organosulfide addition. Miami Fort personnel reported that they do not target specific metals concentrations for the treatment system effluent. DCN SE04331

[161] FirstEnergy personnel stated that the plant did not have any specific operational targets for metals. The FGD wastewater treatment system was operated based on maintaining the pH, floc in the clarifier, and TSS in the effluent from the sand filter. DCN SE04316

daily basis (this was included as part of the cost basis for the technology option). Pleasant Prairie has effectively used mercury analyzers to alert operators when mercury concentrations begin trending upward so that they may take steps (such as altering the dosage rates for chemical additives) to adjust treatment system performance to meet their current permit limitations.

Optimizing the treatment system to target effluent concentrations at the long-term average is important, and is relevant to the evaluation of the effluent data for Hatfield's Ferry and Pleasant Prairie. EPA evaluated the results of testing a chemical precipitation system at a power plant that, although the treatment system had been in operation for more than a year and was operating at a steady-state condition, the plant was able to significantly improve the pollutant removal performance merely by altering the dosage rates of the wastewater treatment chemical additives.[162] The results of this study, as well as other information evaluated for the ELGs, supports EPA's determination that these plants can improve treatment system performance and meet the ELG limitations at all times. EPA notes that its compliance cost estimates for the final rule include costs for mercury analyzers, organosulfide addition, proper dosing of treatment system chemical additives, and increased staffing to operate the treatment system.

It is important to note that, although the BAT limitations and PSES for arsenic and mercury in the final ELGs are based on chemical precipitation technology,[163] the selected BAT/PSES technology option for FGD wastewater actually comprises the combination of chemical precipitation followed by biological treatment, which is more effective than chemical precipitation treatment alone. The data evaluated for the ELGs for the final rule demonstrate that the biological treatment stage reduces levels of arsenic and mercury (and other pollutants of concern with similar removal mechanisms) in addition to the pollutant removals that occur in the chemical precipitation stage of the biological treatment technology option (e.g., see the data plots and tables in DCN SE05733, showing an average of 31 percent removal of arsenic and 99 percent removal of mercury across the biological treatment stage at Allen and Belews Creek).

These additional pollutant removals are corroborated by the results of pilot testing conducted at Indianapolis Power and Light's Petersburg power plant, which showed that the

[162] AEP's Mountaineer plant operated a chemical precipitation system to treat FGD wastewater, with operation targeted to meet only the BPT-based limitations for TSS, pH, and oil and grease. In 2008, one year after the start-up of the FGD scrubbers and the FGD wastewater treatment system, the plant went through a permit renewal process whereby the permitting authority proposed to add a water quality-based effluent limit for mercury. Based on the mercury limitations in the draft permit, AEP conducted a pilot study evaluating three different technologies that could be installed to further treat the effluent from the chemical precipitation system. AEP conducted the pilot study from July through December 2008. During the first three months of the study, the mercury concentrations of the chemical precipitation system effluent feeding the pilot tests averaged 1,300 ng/L. Since none of the three technologies were achieving the targeted effluent concentrations for the pilot testing, AEP took steps to optimize the precipitation of dissolved metals and the removal of precipitants and other suspended solids in the chemical precipitation system, including adding additional polymers and organosulfide. Using these optimization steps, AEP noted that "[t]he combination of supplemental coagulation and organosulfide addition consistently yielded approximately 80 percent of additional mercury reduction…" within the chemical precipitation system. American Electric Power Mercury Removal Effectiveness Report. DCN SE02008.

[163] See Section 13.7.2 for a discussion of the transfer of effluent limitations for arsenic and mercury from chemical precipitation technology to the selected BAT technology option (chemical precipitation followed by biological treatment).

biological treatment stage effectively removed both arsenic and mercury.[164] Data for a full-scale FGD wastewater treatment system at AEP's Mountaineer plant similarly show effective removal of both arsenic and mercury by the biological treatment stage.[165] Thus, plants using and optimally operating all components of the biological treatment technology option (including adding organosulfide to achieve sulfide precipitation) should achieve pollutant removals for arsenic and mercury (and other pollutants with similar removal mechanisms) that are even greater than the removals based on chemical precipitation technology alone.

Selenium and Nitrate-nitrite as N Limitations for FGD Wastewater, Based on Chemical Precipitation Followed by Biological Treatment Technology Option for FGD Wastewater

The final rule establishes BAT limitations/PSES for arsenic, mercury, nitrate-nitrite as N, and selenium in FGD wastewater based on the biological treatment technology option. As mentioned above, the limitations for arsenic and mercury were transferred from the chemical precipitation technology option. See the discussion above for the comparison of effluent data to the limitations for these two pollutants. EPA calculated the effluent limitations for selenium and nitrate-nitrite as N using data from two model plants: Allen and Belews Creek.

- *Nitrate-nitrite as N – Comparison of effluent data to the daily maximum limit of 17 mg/L:*
  - For both Allen and Belews Creek, all observations were below the daily limit (30 observations at Allen; 40 observations at Belews Creek).
- *Nitrate-nitrite as N – Comparison of effluent data to the monthly average limit of 4.4 mg/L:*
  - Only Belews Creek collected effluent samples frequently enough within a month to represent weekly sampling. For the time periods where there were sufficient data, EPA calculated the average of the daily values collected within a month, and compared that average value to the monthly average limit. All of the monthly average values for Belews Creek were below the limit. Although Allen did not collect samples with sufficient frequency to calculate monthly averages, all but two of the daily observations for the plant were below the monthly limit. The two daily observations that were above the monthly limit are associated with a spike in effluent concentration that occurred in December 2011.
- *Selenium – Comparison of effluent data to the daily maximum limit of 23 ug/L:*

[164] Higgins, T., et al. "Recent Applications of Meeting Compliance Challenges through Flue Gas Desulfurization (FGD) Wastewater," Presented at the Power Plant Pollutant Control "MEGA" Symposium. August 19-21, 2014. Also see June 6, 2015 email from Tom Higgins (CH2M Hill), presenting data showing the biological treatment stage removed 87 percent of the mercury and 84 percent of the arsenic entering that stage.

[165] The FGD wastewater treatment system at AEP's Mountaineer plant includes chemical precipitation (both hydroxide and sulfide precipitation, as well as iron coprecipitation) followed by anoxic/anaerobic biological treatment designed to remove selenium. DCN SE05664/SE05645

  - Of the 182 total observations at Allen, 178 were below the daily limit and four were above the daily limit. Of the 216 total observations at Belews Creek, 214 were below the daily limit and two were above the daily maximum limit.

- *Selenium – Comparison of effluent data to the monthly average limit of 12 ug/L:*
  - All monthly averages for Allen were below the monthly average. At Belews Creek, there were 10 months when the monthly average was equal to or below the monthly limit and 2 months when the average was above the limit. Both of these months occurred shortly after the end of the initial commissioning period for the treatment system on 6/11/2008; the two monthly averages above the monthly limit were in August and September 2008.

EPA determined that all power plants discharging FGD wastewater, including the plants discussed here, are capable of meeting the effluent limitations for selenium and nitrate-nitrite as N. While there were certain instances where the model plants' effluent data concentrations are higher the final limitations, based on its engineering judgment developed over years of evaluating wastewater treatment processes for power plants and other industrial sectors, including both physical/chemical and biological treatment technologies, EPA determined that the combination of additional monitoring, closer operator attention, and optimizing treatment system performance to target the effluent concentrations at the technology option long-term averages will result in lower effluent concentrations that would comply with the effluent limitations.

Although most observations in the datasets used to calculate the effluent limitations were below the limitations, there were some observations above the limitations. It is reasonable for this situation to arise in datasets used to calculate limitations for ELGs, particularly when the data are from plants that do not have NPDES limitations for the pollutants, and there are specific steps that the plants can take to improve treatment system performance so that effluent concentrations would comply with the limitations at all times. Although EPA selected these plants as representing the best available technology, neither plant's system is fully optimized for removing selenium or nitrate-nitrite because they are not targeting specific effluent levels for these pollutants or operationally controlling the treatment system (e.g., adjusting dosages for chemical additives or altering bioreactor bed contact time) to maintain effluent concentrations below specified concentrations. Neither plant's NPDES permit includes effluent limitations or monitoring requirements for nitrate-nitrite. The NPDES permits for these plants also do not include effluent limitations for selenium, although the permits do require them to periodically monitor effluent concentrations of selenium.[166,167]

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[166] Allen's NPDES permit (NC0004979) FGD wastewater monitoring requirements include both in-plant requirements (Internal Outfall 005, effluent from the FGD wet scrubber wastewater treatment system) and final outfall requirements (Outfall 002, ash pond effluent including FGD wastewater and other wastestreams). Internal Outfall 005 includes no effluent limitations or monitoring requirement for nitrate-nitrite as N; selenium also has no effluent limit and is required to be monitored monthly. Outfall 002 also includes no effluent limitations or monitoring requirement for nitrate-nitrite as N; selenium has no effluent limit and is required to be monitored monthly.

[167] Belews Creek's NPDES permit (NC0024406) FGD wastewater monitoring requirements include both in-plant requirements (Internal Outfall 002, treated FGD wet scrubber wastewater to ash settling basin) and final outfall requirements (Outfall 003, discharge to the Dan River from the ash settling pond, which contains treated FGD

For selenium at Allen and Belews Creek, EPA identified a small number of observations that are above the daily limitation, or where the monthly average is above the monthly limitation. As explained above, there are steps plants can take to achieve better treatment system performance to ensure compliance with the effluent limitations. EPA evaluated all selenium data for the biological treatment technology option (more than 5 years of data for Belews Creek and more than 4 years for Allen, excluding the initial commissioning periods for the treatment systems). EPA concluded that the observations above the daily limitation reflect periods of less than optimum performance of the treatment system and were due either to operators inexperienced with this type of treatment system, operators not targeting their treatment systems to obtain a specific effluent concentration, or operators failing to either closely monitor treatment system performance or to respond in a timely manner to restore the system to steady-state condition, or a combination thereof.[168] For example, the monthly averages at Belews Creek that are above the limitations occurred only 2-3 months following the end of the initial commissioning period and are associated with significantly higher daily observations relative to other observations in the months immediately following that time, as well as nearly every other daily observation for Belews Creek. Likewise, the observations at Allen that are above the daily limitation are associated with two periods when the effluent selenium concentrations spike upward significantly and the effluent concentration of nitrate-nitrite spiked upward suddenly during one of those periods. These effluent spikes indicate that the nutrient feed may have been insufficient or the bed contact time may not have been long enough to allow the microorganisms in the bioreactor to complete the biochemical reduction processes for nitrate-nitrite and selenium.

Both plants could take steps to ensure compliance with the final limitations by adjusting the treatment system operation to target the long-term average performance that the effluent limitations are based upon (i.e., 1.3 mg/L for nitrate-nitrite as N and 7.5 ug/L for selenium). Operator attention to influent and effluent quality and process control indicators (e.g., wastewater flow rates, oxidation reduction potential (ORP), TSS, turbidity, gas production rates) facilitate steady-state operation of the treatment system, as well as alerting operators of system abnormalities or fluctuations in wastewater flow rate or quality (influent or effluent). Significant changes in wastewater flow rate, if not managed properly, can affect effluent quality because they will affect the bed contact time, as well as potentially affecting the appropriate nutrient dosage. The influent ORP provides insight to the amount of nutrient that should be added to maintain the appropriate carbon to nitrogen (C:N) ratio to support the microbial activity needed to reduce nitrate-nitrite and selenium. The plant should monitor the ORP within the bioreactor to

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wastewater and other wastes). Internal Outfall 002 includes no effluent limitations or monitoring requirement for nitrate-nitrite as N; selenium also has no effluent limit but must be monitored quarterly. Outfall 003 also includes no effluent limitations or monitoring requirement for nitrate-nitrite as N; selenium has no effluent limit but must be monitored monthly.

[168] Note that although the Belews Creek selenium data (and other pollutants as well) from mid-2008 may be influenced by the initial commissioning period for the treatment system, EPA used these data when calculating the final effluent limitations for the biological treatment technology option for FGD wastewater. EPA used these data because although EPA believes that, as a general rule, the initial commissioning period will be 3-4 months, and certainly no more than 6 months except in unique circumstances; EPA has not confirmed that the initial commissioning for Belews Creek was of such exceptional duration. Comments on the proposed ELGs stated that the treatment system operators at Belews Creek reported 6/11/2008 as the end of the initial commissioning period. Without additional information to confirm whether the initial commissioning period was still in progress after that date, EPA concluded that the sampling data should be used when calculating effluent limitations.

ensure that the wastewater has sufficient bed contact time with the biomass at low (-300 to -400 megavolts (mV)) ORP for sufficient time for selenium reduction. Properly operating the system includes being attentive to changes in pressure drop across the system to ensure the routine flush/backwash cycles are occurring often enough.

EPA notes that the compliance cost estimates for the final rule include costs for ORP monitoring of the wastewater influent and within the bioreactor, proper dosing of the nutrient additives, chemical feed system to remove free oxidants prior to the bioreactor, and increased staffing to operate the treatment system. Some plants may find it desirable to implement additional process controls, such as frequent monitoring of nitrates or selenium (e.g., daily or once per shift) with available test kits or analyzers, although they are not necessary to operate the treatment system properly. Although some of these test kits may not be approved in 40 CFR Part 136 for NPDES purposes, plants can correlate their analytical results to approved methods (such as ICP-MS analysis for selenium) and can use them as another real-time indicator of treatment system influent or effluent characteristics for enhanced process control.[169] Additionally, inexpensive test kits for measuring for oxidants in the treatment system influent are available and can be used as another source of information about wastewater characteristics.

Based on the results of this comparison for the biological treatment technology option, EPA determined that the statistical distributional assumptions are appropriate for the effluent data and that the limitations are reasonable.

Limitations for FGD Wastewater Based on Chemical Precipitation Followed By Vapor-Compression Evaporation (Arsenic, Mercury, Selenium and TDS)

The final rules establishes NSPS/PSNS for arsenic, mercury, selenium, and TDS in FGD wastewater based on the performance of chemical precipitation followed by vapor-compression evaporation treatment using data from the Brindisi plant.[170] All daily concentration values are equal to or below the daily limitations for all parameters. (The data for this plant were not collected at sufficient frequency to represent weekly sampling; thus, EPA could not calculate monthly averages for comparison to the monthly limit.) After thoroughly reviewing the data, EPA determined that the statistical distributional assumptions are appropriate for the effluent data and that the limitations are reasonable and achievable.

Limitations for Gasification Wastewater Based on Vapor-Compression Evaporation (Arsenic, Mercury, Selenium and TDS)

The final rule establishes BAT limitations/PSES and NSPS/PSNS for arsenic, mercury, selenium and TDS in gasification wastewater based on vapor-compression evaporation treatment. The Agency calculated the limitations for selenium and TDS using data from two

[169] Similar to the mercury analyzer included as part of the technology basis for the effluent limitations, these additional process control options can provide treatment system operators with additional information, such as the influent nitrate-nitrite concentrations (for use in addition to ORP to confirm the appropriate nutrient dosage), between stage or effluent nitrate-nitrite concentrations (further confirmation of the nutrient dosage to support microbial activity for pollutant reduction), or effluent selenium concentrations.

[170] The final rule also establishes BAT limitations for FGD wastewater that are the same as the NSPS for FGD wastewater for plants who opt into the voluntary incentives program.

plants: Polk and Wabash River plants. The limitations for arsenic and mercury were based only on data from Polk, because the arsenic and mercury data from Wabash River failed the LTA test (see Section 3.4 for a discussion of the LTA test).

For arsenic and mercury, the daily concentration values used to calculate the limitations (i.e., from Polk) are below the daily limitations.[171] For TDS, all observations for both Polk and Wabash River are below the daily limit.

For selenium, all observations for Wabash River were below the daily limit. At Polk, there is one observation above the daily limit. As discussed in Section 3.9, the data for the Polk treatment system indicates that the evaporator (or at a minimum the forced circulation evaporation stage) was operating abnormally and allowing carryover of pollutants to the condensate effluent stream.[172] Based upon its review of the data, EPA concluded if the plant designs and operates its treatment system to achieve the option long-term average for the model technology, then the plant will be able to comply with the limitations. Furthermore, EPA notes that Polk reuses all treated gasification wastewater (i.e., condensate) in the gasification process and does not discharge any gasification wastewater. As such, the plant's treatment objective is to ensure the wastewater is of sufficient quality for reuse in the process rather than to comply with a NPDES permit limit.

The data for these plants were not collected frequently enough to represent weekly sampling; thus, EPA could not calculate monthly averages for comparison to the monthly limitations.

After thoroughly reviewing the data, EPA concluded that the statistical distributional assumption is appropriate for the effluent data and that the limitations are reasonable.

13.9.2 Comparison of Final Limitations to Influent Data

In addition to comparing the limitations to the effluent data used to develop the limitations, EPA also compared the pollutant concentrations for the treatment system influent to the daily limitations. For all treatment technology options for both FGD and gasification wastewater, the minimum, average, and maximum influent concentration values were much higher than the long-term average and final limitations. EPA found that influent concentrations were generally well-controlled by the treatment plant for all plants with model technology. In general, the treatment systems adequately treated even the extreme influent values, and the high effluent values did not appear to be the result of high influent discharges.

[171] Although it did not use the arsenic and mercury data for the vapor-compression evaporator condensate at Wabash River to calculate the limitations, due to failing the LTA test, EPA nevertheless compared these data to the limitations and found that all observations were equal to or below both the daily and monthly limitations.

[172] EPA did not use Polk's data for the forced circulation evaporator condensate to calculate the limitations due to that portion of the treatment system being in an upset condition; therefore, the Agency did not compare these data to the effluent limitations.

13.10 REFERENCES

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SECTION 14
REGULATORY IMPLEMENTATION

This section provides guidance to permit writers, control authorities and steam electric power plants in implementing the revisions to the steam electric ELGs.

14.1 IMPLEMENTATION OF THE LIMITATIONS AND STANDARDS

The requirements in the rule apply to discharges from steam electric power plants through incorporation into NPDES permits issued by the EPA or authorized states under Section 402 of the Act and through local pretreatment programs under Section 307 of the Act. Permits or control mechanisms issued after the final rule's effective date must incorporate the ELGs, as applicable. Also, under Section 510 of the CWA, states can require effluent limitations under state law as long as they are no less stringent than the requirements of this rule. Finally, in addition to requiring application of the technology-based ELGs in the final rule, Section 301(b)(1)(C) of CWA requires the permitting authority to impose more stringent effluent limitations, as necessary, to meet applicable water quality standards.

14.1.1 Requirements

This rule establishes new BAT, NSPS, PSES, and PSNS requirements for the following wastestreams: FGD wastewater, fly ash transport water, bottom ash transport water, FGMC wastewater, gasification wastewater, and combustion residual leachate. In some cases, the new BAT limitations are equal to previously established BPT limitations. The exact requirements may vary depending on the size of the steam electric generating unit, the fuel used in the steam electric generating unit, whether the discharge is from an existing or new source, the date on which the wastewater is generated, and the discharge type (directly to a surface water or indirectly to a POTW).

The following tables summarize both the requirements from this rule and the previously established requirements for FGD wastewater, fly ash transport water, bottom ash transport water, FGMC wastewater, gasification wastewater, and combustion residual leachate for different scenarios. For the purpose of the requirements for direct dischargers in Table 14-1 and the rest of the information in Section 14, legacy wastewater is FGD wastewater, fly ash transport water, bottom ash transport water, FGMC wastewater, or gasification wastewater generated prior to the date established by the permitting authority that is as soon as possible beginning November 1, 2018, but no later than December 31, 2023.[173]

[173] For plants voluntarily opting into the voluntary incentives program, legacy wastewater includes all these wastewaters, except for FGD wastewater. For plants in the voluntary incentives program, legacy FGD wastewater is FGD wastewater generated prior to December 31, 2023.

Table 14-1. BPT/BAT Limitations for Existing Units > 50 MW and Not Oil-Fired Units; Not Also Subject to 1982 NSPS

Wastestream	Pollutant	Applicable Requirements[a]	Date by Which Limits Must Be Achieved
FGD wastewater–legacy wastewater[b]	TSS, Oil and Grease	BPT—423.12(b)(11) BAT—423.13(g)(1)(ii) BAT voluntary incentives program— 423.13(g)(3)(ii)	BPT limits must already be met. BAT limits must be met when they are incorporated into an NPDES permit, on or after the effective date of the final rule.
FGD wastewater – generated on or after the as soon as possible date determined by the permitting authority	Arsenic, Mercury, Selenium, Nitrate/Nitrite as N	BAT—423.13(g)(1)(i)	As soon as possible beginning November 1, 2018, but no later than December 31, 2023; determined by permitting authority (must be incorporated into an NPDES permit).
	TSS, Oil and Grease	BPT—423.12(b)(11)	
FGD wastewater – generated after Dec. 2023 by plants in the voluntary incentives program	Arsenic, Mercury, Selenium, TDS	BAT—423.13(g)(3)(i)	Dec. 31, 2023 (must be incorporated into an NPDES permit).
	TSS, Oil and Grease	BPT—423.12(b)(11)	
Fly ash transport water – legacy wastewater	TSS, Oil and Grease	BPT—423.12(b)(4) BAT—423.13 (h)(1)(ii)	BPT limits must already be met. BAT limits must be met when they are incorporated into an NPDES permit, on or after the effective date of the final rule.
Fly ash transport water – generated on or after the as soon as possible date determined by the permitting authority	All	BAT—423.13(h)(1)(i) BPT—423.12(b)(4)	As soon as possible beginning November 1, 2018, but no later than December 31, 2023; determined by permitting authority (must be incorporated into an NPDES permit).
Flue Gas Mercury Control wastewater – legacy wastewater	TSS, Oil and Grease	BPT—423.12(b)(11) BAT—423.13(i)(1)(ii)	BPT limits must already be met. BAT limits must be met when they are incorporated into an NPDES permit, on or after the effective date of the final rule.
Flue Gas Mercury Control wastewater – generated on or after the as soon as possible date determined by the permitting authority	All	BAT—423.13(i)(1)(i) BPT—423.12(b)(11)	As soon as possible beginning November 1, 2018, but no later than December 31, 2023; determined by permitting authority (must be incorporated into an NPDES permit).
Bottom ash transport water - legacy wastewater	TSS, Oil and Grease	BPT—423.12(b)(4) BAT—423.13(k)(1)(ii)	BPT limits must already be met. BAT limits must be met when they are incorporated into an NPDES permit, on or after the effective date of the final rule.

Table 14-1. BPT/BAT Limitations for Existing Units > 50 MW and Not Oil-Fired Units; Not Also Subject to 1982 NSPS

Wastestream	Pollutant	Applicable Requirements[a]	Date by Which Limits Must Be Achieved
Bottom ash – generated on or after the as soon as possible date determined by the permitting authority	All	BAT—423.13(k)(1)(i) BPT—423.12(b)(4)	As soon as possible beginning November 1, 2018, but no later than December 31, 2023; determined by permitting authority (must be incorporated into an NPDES permit).
Combustion residual leachate – generated at any time	TSS, Oil and Grease	BPT—423.12(b)(11) BAT—423.13(l)	BPT limits must already be met. BAT limits must be met when they are incorporated into an NPDES permit, on or after the effective date of the final rule.
Gasification wastewater – legacy wastewater	TSS, Oil and Grease	BPT—423.12(b)(11) BAT—423.13(j)(1)(ii)	BPT limits must already be met. BAT limits must be met when they are incorporated into an NPDES permit, on or after the effective date of the final rule.
Gasification wastewater – generated on or after the as soon as possible date determined by the permitting authority	Arsenic, Mercury, Selenium, TDS	BAT—423.13(j)(1)(i)	As soon as possible beginning November 1, 2018, but no later than December 31, 2023; determined by permitting authority (must be incorporated into an NPDES permit).
	TSS, Oil and Grease	BPT—423.12(b)(11)	

a – All the applicable regulations are listed in this column, even if one regulation is expansive enough to include the requirements of another (*e.g.*, BPT limits for TSS and Oil and Grease, BAT limits for just TSS; or BAT limits for all pollutants, BPT limits for just TSS and Oil and Grease).

b – As used in these tables, "legacy wastewater" is wastewater generated prior to the date determined by the permitting authority that is as soon as possible beginning November 1, 2018, but no later than December 31, 2023, except for FGD wastewater generated by plants in the voluntary incentives program. For plants in the voluntary incentives program, legacy FGD wastewater is FGD wastewater generated prior to December 31, 2023.

Table 14-2. BAT/NSPS Limitations for Existing Units > 50 MW and Not Oil-Fired Units; Also Subject to 1982 NSPS[a]

Wastestream	Pollutant	Applicable Requirements	Date by Which Standards Must Be Achieved
FGD wastewater– generated at any time	TSS, Oil and Grease	1982 NSPS—423.15(a)(3)	1982 NSPS must already be met.
FGD wastewater – generated on or after the as soon as possible date determined by the permitting authority	Arsenic, Mercury, Selenium, Nitrate/Nitrite as N	BAT—423.13(g)(1)(i)	As soon as possible beginning November 1, 2018, but no later than December 31, 2023; determined by permitting authority (must be incorporated into an NPDES permit).
Fly ash transport water – generated at any time	All	1982 NSPS—423.15(a)(7)	1982 NSPS must already be met.

Table 14-2. BAT/NSPS Limitations for Existing Units > 50 MW and Not Oil-Fired Units; Also Subject to 1982 NSPS[a]

Wastestream	Pollutant	Applicable Requirements	Date by Which Standards Must Be Achieved
Fly ash transport water – generated on or after the as soon as possible date determined by the permitting authority	All	BAT—423.13(h)(1)(i)	As soon as possible beginning November 1, 2018, but no later than December 31, 2023; determined by permitting authority (must be incorporated into an NPDES permit).
Flue Gas Mercury Control wastewater-generated at any time	TSS, Oil and Grease	1982 NSPS—423.15(a)(3)	1982 NSPS must already be met.
Flue Gas Mercury Control wastewater – generated on or after the as soon as possible date determined by the permitting authority	All	BAT—423.13(i)(1)(i)	As soon as possible beginning November 1, 2018, but no later than December 31, 2023; determined by permitting authority (must be incorporated into an NPDES permit).
Bottom ash water – generated at any time	TSS, Oil and Grease	1982 NSPS—423.15(a)(6)	1982 NSPS must already be met.
Bottom ash – generated on or after the as soon as possible date determined by the permitting authority	All	BAT—423.13(k)(1)(i)	As soon as possible beginning November 1, 2018, but no later than December 31, 2023; determined by permitting authority (must be incorporated into an NPDES permit).
Combustion residual leachate – generated at any time	TSS, Oil and Grease	1982 NSPS—423.15(a)(3)	1982 NSPS must already be met.
Combustion residual leachate – generated on or after the as soon as possible date determined by the permitting authority	TSS	BAT—423.13(l)	BAT limits must be met when they are incorporated into an NPDES permit, on or after the effective date of the final rule.
Gasification wastewater – generated at any time	TSS, Oil and Grease	1982 NSPS—423.15(a)(3)	1982 NSPS must already be met.
Gasification wastewater - generated on and after the as soon as possible date determined by the permitting authority	Arsenic, Mercury, Selenium, TDS	BAT—423.13(j)(1)(i)	As soon as possible beginning November 1, 2018, but no later than December 31, 2023; determined by permitting authority (must be incorporated into an NPDES permit).

a – The plants subject to the 1982 NSPS area also subject to the 2015 BAT.

Table 14-3. BPT/BAT Limitations for Existing Units (< or Equal To 50 MW or Oil-Fired Units); Not Also Subject to 1982 NSPS

Wastestream	Pollutant	Applicable Requirements[a]	Date by Which Limits Must Be Achieved
FGD wastewater	TSS, Oil and Grease	BPT—423.12(b)(11) BAT—423.13(g)(2)	BPT limits must already be met. BAT limits must be met when they are incorporated into an NPDES permit, on or after the effective date of the final rule.
Fly ash transport water	TSS, Oil and Grease	BPT—423.12(b)(4) BAT—423.13(h)(2)	BPT limits must already be met. BAT limits must be met when they are incorporated into an NPDES permit, on or after the effective date of the final rule.
Flue Gas Mercury Control wastewater	TSS, Oil and Grease	BPT—423.12(b)(11) BAT— 423.13(i)(2)	BPT limits must already be met. BAT limits must be met when they are incorporated into an NPDES permit, on or after the effective date of the final rule.
Bottom ash transport water	TSS, Oil and Grease	BPT—423.12(b)(4) BAT—423.13(k)(2)	BPT limits must already be met. BAT limits must be met on the effective date of the final rule.
Combustion residual leachate	TSS, Oil and Grease	BPT—423.12(b)(11) BAT—423.13(l)	BPT limits must already be met. BAT limits must be met when they are incorporated into an NPDES permit, on or after the effective date of the final rule.
Gasification wastewater	TSS, Oil and Grease	BPT—423.12(b)(11) BAT—423.13(j)(2)	BPT limits must already be met. BAT limits must be met when they are incorporated into an NPDES permit, on or after the effective date of the final rule.

a – All the applicable regulations are listed in this column, even if one regulation is expansive enough to include the requirements of another (*e.g.*, BPT limits for TSS and Oil and Grease, BAT limits for just TSS).

Table 14-4. BAT/NSPS Limitations for Existing Units (< or Equal To 50 MW or Oil-Fired Units); Also Subject to 1982 NSPS[a]

Wastestream	Pollutant	Applicable Requirements	Date by Which Standards Must Be Achieved
FGD wastewater– generated at any time	TSS, Oil and Grease	1982 NSPS—423.15(a)(3)	1982 NSPS must already be met.
FGD wastewater – generated on or after the as soon as possible date determined by the permitting authority	TSS	BAT—423.13(g)(2)	BAT limits must be met when they are incorporated into an NPDES permit, on or after the effective date of the final rule.
Fly ash transport water – generated at any time	All	1982 NSPS—423.15(a)(7)	1982 NSPS must already be met.
Fly ash transport water – generated on or after the as soon as possible date determined by the permitting authority	TSS	BAT—423.13(h)(2)	BAT limits must be met when they are incorporated into an NPDES permit, on or after the effective date of the final rule.
Flue Gas Mercury Control wastewater- generated at any time	TSS, Oil and Grease	1982 NSPS—423.15(a)(3)	1982 NSPS must already be met.
Flue Gas Mercury Control wastewater – generated on or after the as soon as possible date determined by the permitting authority	TSS	BAT—423.13(i)(2)	BAT limits must be met when they are incorporated into an NPDES permit, on or after the effective date of the final rule.
Bottom ash water – generated at any time	TSS, Oil and Grease	1982 NSPS—423.15(a)(6)	1982 NSPS must already be met.
Bottom ash – generated on or after the as soon as possible date determined by the permitting authority	TSS	BAT—423.13(k)(2)	BAT limits must be met when they are incorporated into an NPDES permit, on or after the effective date of the final rule.
Combustion residual leachate – generated at any time	TSS, Oil and Grease	1982 NSPS—423.15(a)(3)	1982 NSPS must already be met.
Combustion residual leachate – generated on or after the as soon as possible date determined by the permitting authority	TSS	BAT—423.13(l)	BAT limits must be met when they are incorporated into an NPDES permit, on or after the effective date of the final rule.
Gasification wastewater – generated at any time	TSS, Oil and Grease	1982 NSPS—423.15(a)(3)	1982 NSPS must already be met.

Table 14-4. BAT/NSPS Limitations for Existing Units (< or Equal To 50 MW or Oil-Fired Units); Also Subject to 1982 NSPS[a]

Wastestream	Pollutant	Applicable Requirements	Date by Which Standards Must Be Achieved
Gasification wastewater - generated on and after the as soon as possible date determined by the permitting authority	TSS	BAT—423.13(j)(2)	BAT limits must be met when they are incorporated into an NPDES permit, on or after the effective date of the final rule.

Table 14-5. 2015 NSPS Limitations for New Sources

Wastestream	Pollutant	Requirement	Date by Which Limits Must Be Achieved
FGD wastewater	Arsenic, Mercury, Selenium, TDS	2015 NSPS—423.15(b)(13)	When they are incorporated into an NPDES permit for a new source, on or after the effective date of the final rule.
Fly ash transport water	All	2015 NSPS—423.15(b)(7)	When they are incorporated into an NPDES permit for a new source, on or after the effective date of the final rule.
Flue Gas Mercury Control wastewater	All	2015 NSPS—423.15(b)(14)	When they are incorporated into an NPDES permit for a new source, on or after the effective date of the final rule.
Bottom ash transport water	All	2015 NSPS—423.15(b)(6)	When they are incorporated into an NPDES permit for a new source, on or after the effective date of the final rule.
Combustion residual leachate	Arsenic and Mercury	2015 NSPS—423.15(b)(16)	When they are incorporated into an NPDES permit for a new source, on or after the effective date of the final rule.
	TSS, Oil and Grease	2015 NSPS—423.15(b)(3)	
Gasification wastewater	Arsenic, Mercury, Selenium, TDS	2015 NSPS—423.15(b)(15)	When they are incorporated into an NPDES permit for a new source, on or after the effective date of the final rule.

Table 14-6. PSES for Existing Units > 50 MW and Not Oil-Fired Units; Not Also Subject to 1982 PSNS

Wastestream[a]	Pollutant	Requirement	Date by Which Limits Must Be Achieved
FGD wastewater – generated on or after November 1, 2018	Arsenic, Mercury, Selenium, Nitrate/Nitrite as N	PSES—423.16(e)	As of November 1, 2018
Fly ash transport water- generated on or after November 1, 2018	All	PSES—423.16(f)	As of November 1, 2018
Flue Gas Mercury Control wastewater- generated on or after November 1, 2018	All	PSES—423.16(h)	As of November 1, 2018
Bottom ash transport water- generated on or after November 1, 2018	All	PSES—423.16(g)	As of November 1, 2018
Gasification wastewater- generated on or after November 1, 2018	Arsenic, Mercury, Selenium, TDS	PSES—423.16(i)	As of November 1, 2018

a – There are no requirements for discharges of combustion residual leachate or any of these wastestreams if the wastewater is generated prior to November 1, 2018. There are also no requirements for discharges from units less than or equal to 50 MW or oil-fired generating units.

Table 14-7. PSES for Existing Units >50 MW and Not Oil-Fired Units; Also Subject to 1982 PSNS

Wastestream[a]	Pollutant	Requirement	Date by Which Limits Must Be Achieved
FGD wastewater- generated on or after November 1, 2018	Arsenic, Mercury, Selenium, Nitrate/Nitrite as N	PSES—423.16(e)	As of November 1, 2018
Fly ash transport water	All	1982 PSNS—423.17(a)(5)	1982 PSNS must already be met
Flue Gas Mercury Control wastewater – generated on or after November 1, 2018	All	PSES—423.16(h)	As of November 1, 2018
Bottom ash transport water – generated on or after November 1, 2018	All	PSES—423.16(g)	As of November 1, 2018
Gasification wastewater – generated on or after November 1, 2018	Arsenic, Mercury, Selenium, TDS	PSES—423.16(i)	As of November 1, 2018

a – There are no requirements for combustion residual leachate or any of these wastestreams for wastewater, other than fly ash transport water, if generated prior to November 1, 2018. There are also no requirements for units less than or equal to 50 MW or oil-fired units.

Table 14-8. 2015 PSNS for New Sources

Wastestream	Pollutant	Requirement	Date by Which Limits Must Be Achieved
FGD wastewater	Arsenic, Mercury, Selenium, TDS	2015 PSNS—423.17(b)(6)	Effective date of the final rule
Fly ash transport water	All	2015 PSNS—423.17(b)(5)	Effective date of the final rule
Flue Gas Mercury Control wastewater	All	2015 PSNS—423.17(b)(7)	Effective date of the final rule
Bottom ash transport water	All	2015 PSNS—423.17(b)(8)	Effective date of the final rule
Gasification wastewater	Arsenic, Mercury, Selenium and Total Dissolved Solids	2015 PSNS—423.17(b)(9)	Effective date of the final rule
Leachate	Arsenic and Mercury	2015 PSNS—423.17(b)(10)	Effective date of the final rule

14.1.2 Timing

As shown in Table 14-1 through Table 14-8, the timing of the final rule's requirements for a particular discharge varies depending on the size of the steam electric generating unit, the fuel used in the steam electric generating unit, whether the discharge is from an existing or new source, the date on which the wastewater is generated, and the discharge type (directly to a surface water or indirectly to a POTW).

The direct discharge effluent limitations in this rule apply only when implemented in an NPDES permit issued to a discharger after the effective date of this rule. Under the CWA, the permitting authority must incorporate these ELGs into NPDES permits as a floor or a minimum level of control. While the rule is effective on its effective date, the rule allows permitting authorities to determine the date when the new effluent limitations for FGD wastewater, fly ash transport water, bottom ash transport water, FGMC wastewater, and gasification wastewater apply to a given discharger. The permitting authority must make these new effluent limitations applicable on November 1, 2018 or determine a specified date for a specific discharger. For any new effluent limitation that is specified to become applicable after November 1, 2018, the specified date must be as soon as possible, but in no case later than December 31, 2023. For dischargers in the voluntary incentives program choosing to meet effluent limitations for FGD wastewater based on the use of evaporation technology, the date for meeting those limitations is December 31, 2023.

For combustion residual leachate, and for certain wastestreams (FGD wastewater, fly ash transport water, bottom ash transport water, FGMC wastewater, and gasification wastewater) at oil-fired generating units and small generating units (50 MW or less), the final BAT limitations apply on the date that a permit is issued to a discharger, following the effective date of this rule. The rule does not build in an implementation period for meeting these limitations, as the BAT limitation on TSS is equal to the previously promulgated BPT limitation on TSS in low volume waste sources and in ash transport water.

Pretreatment standards are self-implementing, meaning they apply directly, without the need for a permit. In this rule, the pretreatment standards for existing sources must be met by November 1, 2018.

The requirements for new source direct and indirect discharges (NSPS and PSNS) provide no extended implementation period. NSPS apply when any NPDES permit is issued to a new source direct discharger, following the effective date of this rule; PSNS apply to any new source discharging to a POTW, as of the effective date of the final rule.

Regardless of when a plant's NPDES permit will expire and a new permit application will be submitted, the plant should immediately begin evaluating how it intends to comply with the requirements of the final ELGs. In cases where significant changes in operation are necessary for compliance with the new effluent limitations, the plant should discuss such changes with the permitting authority and evaluate appropriate steps and a timeline for the changes prior to the permit renewal process.

In cases where a plant's final NPDES permit will be issued after the effective date of the final ELGs, but before November 1, 2018, the permitting authority should apply limitations based on the previously promulgated BPT limitations or the plant's other applicable permit limitations until at least November 1, 2018. The permitting authority should also determine what date represents the soonest date, beginning November 1, 2018, that the plant can meet the final BAT limitations in this rule. The permit should require compliance with the final BAT limitations by that date, making clear that in no case shall the limitations begin to apply later than December 31, 2023. Once the requirements are incorporated into a permit, this requirement assures that the effluent limitations required by the final rule will be met no later than December 31, 2023 in every issued permit and that the effluent limitations will be enforceable even if the permit is administratively continued. For permits that come up for renewal on or after November 1, 2018, the permitting authority should determine the earliest possible date that the plant can meet the limitations in this rule (but in no case later than December 31, 2023), and apply the final limitations as of that date (BPT limitations or the plant's other applicable permit limitations would apply until such date).

As specified by the rule, the "as soon as possible" date determined by the permitting authority is November 1, 2018, unless the permitting authority determines another date after receiving information submitted by the discharger.[174] Assuming that the permitting authority receives relevant information from the discharger, in order to determine what date is "as soon as possible" within the implementation period, the permitting authority must then consider the following factors:

- Time to expeditiously plan (including time to raise capital), design, procure, and install equipment to comply with the requirements of the final rule.
- Changes being made or planned at the plant in response to new or existing requirements at fossil fuel-fired power plants under the Clean Air Act, as well as

[174] Even after the permitting authority receives information from the discharger, it still may be appropriate to determine that November 1, 2018, is "as soon as possible" for that discharger.

regulations for the disposal of coal combustion residuals under subtitle D of the Resource Conservation and Recovery Act.

- For FGD wastewater requirements only, an initial commissioning period to optimize the installed equipment.
- Other factors as appropriate.

With respect to the first factor, the permitting authority should evaluate what operational changes are expected at the plant to meet the new BAT limitations for each wastestream, including the types of new treatment technologies that the plant plans to install, process changes anticipated, and the timeframe estimated to plan, design, procure, and install any relevant technologies. As specified in the second factor, the permitting authority must also consider scheduling for installation of equipment, which includes a consideration of plant changes planned or being made to comply with certain other key rules that affect the steam electric power generating industry. As specified in the third factor, for the FGD wastewater requirements only, the permitting authority must consider whether it is appropriate to allow more time for implementation, in addition to the three years before implementation of the rule begins on November 1, 2018, in order to ensure that the plant has appropriate time to optimize any relevant technologies. EPA's record demonstrates that plants installing the FGD technology basis spent several months optimizing its operation (initial commissioning period). Without allowing additional time for optimization, the plant would likely not be able to meet the limitations because they are based on the operation of optimized systems. See Section 14.1.5 for additional discussion and examples regarding implementation of the final ELGs into NPDES permits.

The "as soon as possible" date determined by the permitting authority may or may not be different for each wastestream. EPA recommends that the permitting authority provide a well-documented justification for how it determined the "as soon as possible" date in the fact sheet or administrative record for the permit. If the permitting authority determines a date later than November 1, 2018, the justification should explain why allowing additional time to meet the limitations is appropriate, and why the discharger cannot meet the final effluent limitations as of November 1, 2018. EPA recommends that the permitting authority consider and discuss factors such as the types of new treatment technologies that the plant plans to install, process changes anticipated, and the timeframe estimated to install and optimize any relevant technologies. In cases where the plant is already operating the BAT technology basis for a specific wastestream (e.g., dry fly ash handling system), operating the majority of the BAT technology basis (e.g., FGD chemical precipitation and biological treatment, without sulfide addition), or expecting that relevant treatment and process changes will be in place prior to November 1, 2018, it would not generally be appropriate to allow additional time beyond that date. Regardless, in all cases, the permitting authority must make clear in the permit what date the plant must meet the limitations, and that date may be no later than December 31, 2023.

Where a discharger chooses to participate in the voluntary incentives program and be subject to effluent limitations for FGD wastewater based on evaporation, the permitting authority must allow the plant up to December 31, 2023, to meet those limitations; again, the permit must make clear that the plant must meet the final limitations by December 31, 2023.

14.1.3 Applicability of 1982 NSPS/PSNS

In 1982, EPA promulgated NSPS/PSNS for certain discharges from new generating units. Regardless of the outcome of the current rulemaking, those generating units that are currently subject to the 1982 NSPS/PSNS will continue to be subject to such standards. In addition, EPA is clarifying in the text of the regulation that generating units to which the 1982 NSPS/PSNS apply will also be subject to the newly promulgated BAT/PSES requirements because they will be existing sources with respect to such new requirements. See Table 14-2 and Table 14-6.

14.1.4 Legacy Wastewater

For purposes of this rule, "legacy wastewater" is FGD wastewater, fly ash transport water, bottom ash transport water, FGMC wastewater, or gasification wastewater that is discharged to waters of the U.S. and generated prior to the date determined by the permitting authority that is as soon as possible beginning November 1, 2018, but no later than December 31, 2023 (see preamble Section VIII.C.7).[175] Under this rule, legacy wastewater must comply with specific BAT limitations, which EPA is setting equal to the previously promulgated BPT limitations on TSS in fly ash and bottom ash transport water and low volume waste sources.

14.1.5 Combined Wastestreams

Most steam electric power plants combine various wastewaters (*e.g.*, FGD wastewater, fly ash and bottom ash transport water) and cooling water either before or after treatment. In such cases, to derive effluent limitations or standards at the point of discharge, the permitting authority typically combines the allowable pollutant concentrations loadings for each set of requirements to arrive at a specific limitation or standard, per pollutant, for the combined wastestream, using the building block approach or combined waste stream formula (CWF). See NPDES Permit Writer's Manual and 40 CFR part 403.6. For concentration-based limitations, rather than mass-based limitations, the effluent limitation or standard for the mixed wastestream is a flow-weighted combination of the appropriate concentration–based limitations or standards for each applicable wastestream. Such a calculation is relatively straightforward if the individual wastestreams are subject to limitations or standards for the same pollutants and the flows of the wastestreams are relatively consistent. This, however, is not the case for all wastestreams at steam electric power plants.

Because EPA anticipates that permitting authorities will apply concentration-based limitations or standards, rather than mass-based limitations or standards, in NPDES permits for steam electric power plants, proper application of the building block approach or CWF is necessary to ensure that the reduced pollutant concentrations observed in a combined discharge reflect proper treatment and control strategies rather than dilution. Where a regulated wastestream is combined with a well-known dilution flow, such as cooling water, non-contaminated stormwater, or cooling tower blowdown, the concentration-based limitation for the regulated wastestream is reduced by multiplying it by a factor.[176] This factor is the total flow for

[175] For plants in the voluntary incentives program, legacy FGD wastewater is FGD wastewater generated prior to December 31, 2023.

[176] As is the case with a single regulated wastestream, if the combined wastestream is not discharged, then the limitations and standards are not applicable.

the combined wastestream minus the dilution flow divided by the total flow for the combined wastestream. In some cases, a wastestream (*e.g.*, FGD wastewater) containing a regulated pollutant (*e.g.*, selenium or mercury) combines with other wastestreams that contain the same pollutant, but that are not regulated for that pollutant (*e.g.*, legacy wastewater contained in a surface impoundment). In these cases, based on the information in its record, EPA strongly recommends that in applying the building block approach or CWF to the regulated pollutant (selenium or mercury, in the example above), permitting authorities either treat the wastestream that does not have a limitation or standard for the pollutant (legacy wastewater contained in a surface impoundment, in the example above) as a dilution flow or determine a concentration for that pollutant based on representative samples of that wastestream.[177]

In all cases where the permitting authority is applying the building block approach or CWF, the permitting authority must also determine the flow rate for use in the building block approach or CWF. EPA strongly recommends that the permitting authority calculate the flow rate based on representative flow rates for each wastestream.

EPA recommends that, where a steam electric power plant chooses to combine two or more wastestreams that would call for the use of the building block approach or CWF to determine the appropriate limitations or standards for the combined wastestream, the plant should be responsible for providing sufficient data that reflect representative samples of each of the individual wastestreams that make up the combined wastestream. EPA strongly recommends that the representative samples reflect a study of each of the applicable wastestreams that covers the full range of variability in concentration and flow for each wastestream.

EPA anticipates that proper application of the building block approach or CWF will result in combined wastestream limitations and standards that will enable steam electric power plants to combine certain wastestreams, while also ensuring that the plant is actually treating its wastewater as intended by the Act and this rule, rather than simply diluting it. EPA's record demonstrates, however, that combined wastestream limitations and standards at the point of discharge, derived using the building block approach or CWF, will be impractical or infeasible for some combined wastestreams because the resulting limitation or standard for <u>any</u> of the regulated pollutants in the combined wastestream would fall below analytical detection levels. In such cases, the permitting authority should establish internal limitations on the regulated wastestream, prior to mixing of the wastestream with others, per 40 CFR § 122.45(h) and 40 CFR § 403.6.[178] See Section 14.1.6 for more examples and details about this guidance.

[177] EPA does not recommend that the permitting authority assume that the pollutant is present at a significant level in the wastestream that does not have a relevant limitation or standard and just apply the same limitation or standard for the pollutant to the mixed wastestream. This will not ensure that treatment and control strategies are being employed to achieve the limitations or standards, rather than simply dilution.

[178] As described earlier for wastestreams with zero discharge limitations or standards, just because a wastestream with a numeric limitation or standard is moved, prior to discharge, for use in another plant process, that does not mean that the wastestream ceases to be subject to the applicable numeric limitation or standard, assuming that the wastestream is eventually discharged.

14.1.6 Implementation Examples

This section presents examples of proper implementation of the BPT and BAT effluent limitations in various scenarios. Throughout these examples, EPA discusses both legacy wastewater (see Section 8.10), as well as wastewater generated on or after the "applicable date" determined by the permitting authority (referred to throughout this section as "newly generated wastewater").

Example 14-1: Plant that Currently Discharges FGD Wastewater

Figure 14-1 presents an example treatment scenario for a plant operating an impoundment receiving only FGD wastewater prior to the implementation of the final ELGs. Under the final rule, the plant will need to meet the new BAT effluent limitations for the newly generated FGD wastewater, in which case, EPA envisions that the plant will have installed a tank-based treatment system to meet the limits. However, the plant has several options for the configuration of the treatment system in association with the existing impoundment, three of which are included in the post rule scenarios in Figure 14-1. Under post rule *Scenario 1*, the plant transfers the newly generated FGD wastewater to the tank-based system and discharges directly from the tank-based system to the receiving water. In this case, the plant would be required to demonstrate compliance (at Monitoring Point Z) with the new BAT and the previously promulgated BPT effluent limitations for the newly generated FGD wastewater at the effluent from the tank-based treatment system (see 40 CFR § 423.12(b)(11) and 40 CFR § 423.13(g)(1)(i)). Additionally, any legacy FGD wastewater that remains in the existing impoundment could still be discharged (e.g., after a rainfall event, when dewatering the impoundment for closure) and would be subject to the legacy FGD wastewater BAT limitations and the previously promulgated BPT effluent limitations (see 40 CFR § 423.12(b)(11) and 40 CFR § 423.13(g)(1)(ii)) at Monitoring Point Y.[179]

Under post rule *Scenario 2*, the plant transfers the newly generated FGD wastewater to the tank-based system and then transfers the effluent from the system to the existing impoundment, containing legacy FGD wastewater, for additional polishing prior to discharge. Under *Scenario 2a*, the permit may specify monitoring for compliance for the combined wastestream at the point of discharge (Monitoring Point Y) using the building block approach as described in Section 14.1.4, if the resulting limitation for each regulated pollutant in the combined wastestream is above the analytical detection level (see 40 CFR § 423.12(b)(11) and 40 CFR § 423.13(g)(1)(ii) for legacy FGD wastewater and 40 CFR § 423.12(b)(11) and 40 CFR § 423.13(g)(1)(i) for newly generated FGD wastewater). If the limitations are not above the analytical detection level for each regulated pollutant, then as under *Scenario 2b*, monitoring at the point of discharge after commingling newly generated FGD wastewater with legacy wastewater contained in the impoundment (Monitoring Point Y) would be unable to demonstrate compliance with the limitation for newly generated FGD wastewater (40 CFR § 423.13(g)(1)(i)). In this case, EPA recommends measuring for compliance prior to commingling (Monitoring Point Z). See 40 CFR 122.46(h). The permit could specify that the plant monitor for compliance with the BPT TSS and oil and grease effluent limitations (see 40 CFR § 423.12(b)(11)) for the

[179] All examples presented in this section focus on the implementation of the ELGs. All NPDES discharge outfalls may also be required to comply with additional water quality-based effluent limitations.

combined wastestream at the point of discharge (Monitoring Point Y) because the legacy FGD wastewater and the newly generated wastewater are subject to the same limitations..

Under post rule *Scenario 3*, the plant transfers the newly generated FGD wastewater to the existing FGD wastewater impoundment that contains legacy FGD wastewater. The effluent from this impoundment is then transferred to the tank-based treatment system. This approach can be used if the resulting limitation using the building block approach for the combined wastestream for each regulated pollutant in the combined wastestream is above the analytical detection level. If this is the case, the plant would demonstrate compliance with the resulting limitations at the effluent from the tank-based treatment system (Monitoring Point Y).

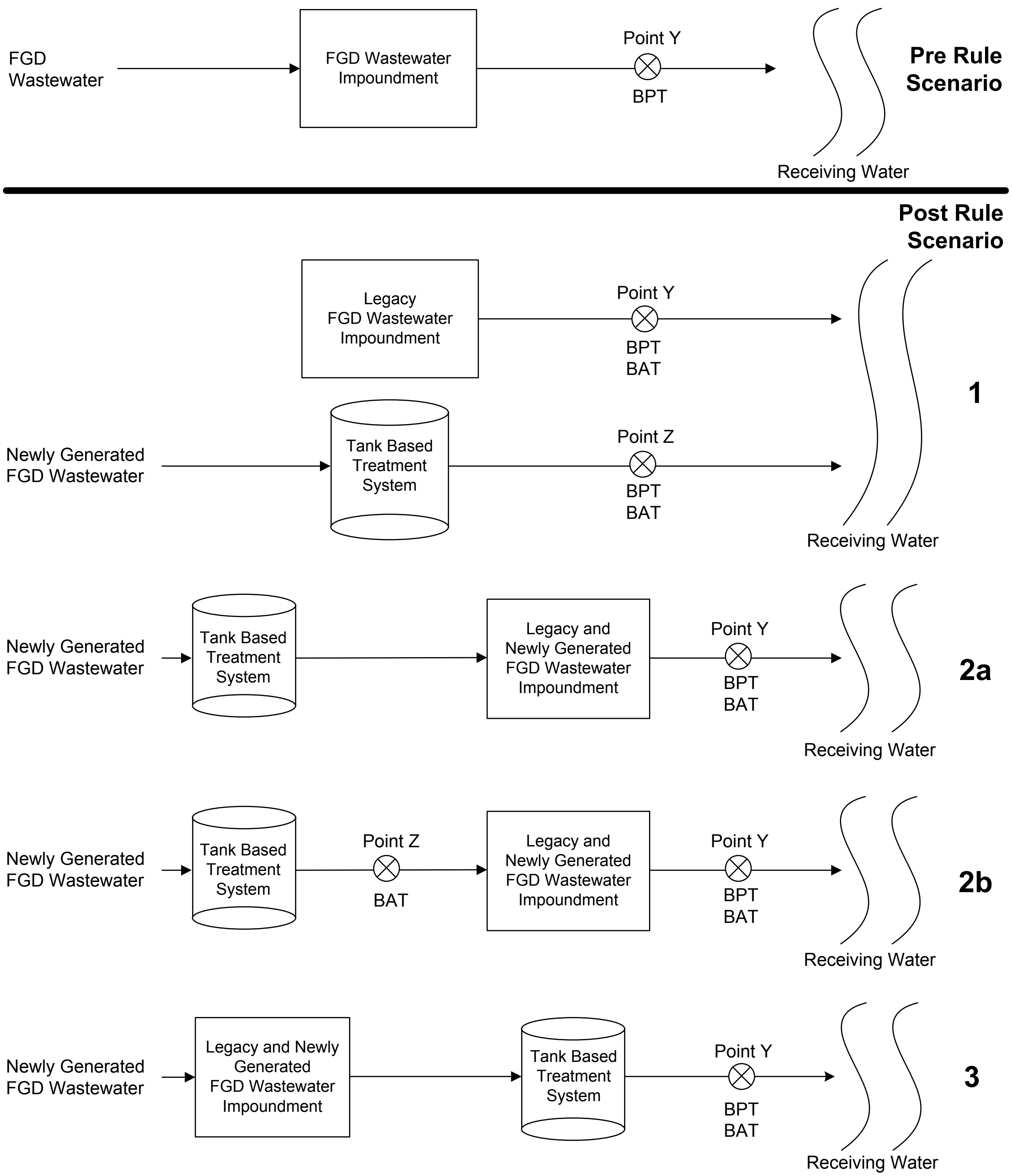

Figure 14-1. Legacy FGD Wastewater Treatment Scenario

Example 14-2: Plant that Currently Discharges Fly Ash Transport Water and FGMC Wastewater

Figure 14-2 presents an example treatment scenario for an impoundment receiving fly ash transport water and FGMC wastewater prior to the implementation of the ELGs. Under the final rule, the plant will need to meet the zero discharge BAT standard for fly ash transport water and FGMC wastewater generated on or after the as soon as possible date determined by the permitting authority. In this example, EPA envisions that the plant will have installed a dry fly ash handling system to meet the new BAT limitation. However, legacy fly ash transport water and FGMC wastewater could still be discharged from the impoundment (e.g., after a rainfall event, when dewatering the impoundment for closure) and would be subject to the legacy fly ash transport water and FGMC wastewater BAT limitations (see 40 CFR § 423.13(h)(1)(ii) and 40 CFR § 423.13(i)(1)(ii)) and previously established BPT limitations (see 40 CFR § 423.12(b)(4)) at Monitoring Point Y.

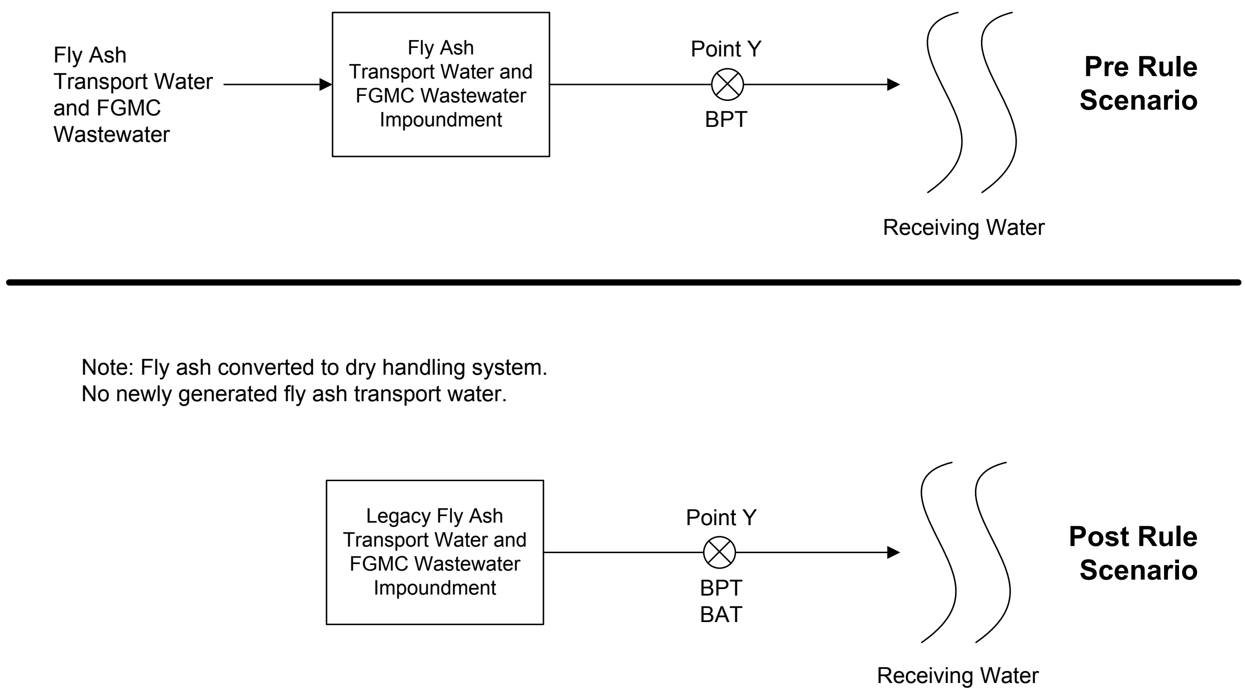

Figure 14-2. Legacy Fly Ash Transport Water and FGMC Wastewater Treatment Scenario

Example 14-3: Plant that Does not Currently Discharge Fly Ash Transport Water

Figure 14-3 presents an example of the treatment scenario for a plant that operates a complete recycle fly ash sluicing system in which the plant does not discharge any fly ash transport water. Because the plant does not discharge fly ash transport water prior to the implementation of the rule, the plant can continue to operate using the same system (i.e., no system modifications required) and still be in compliance with the new zero discharge BAT limitation.

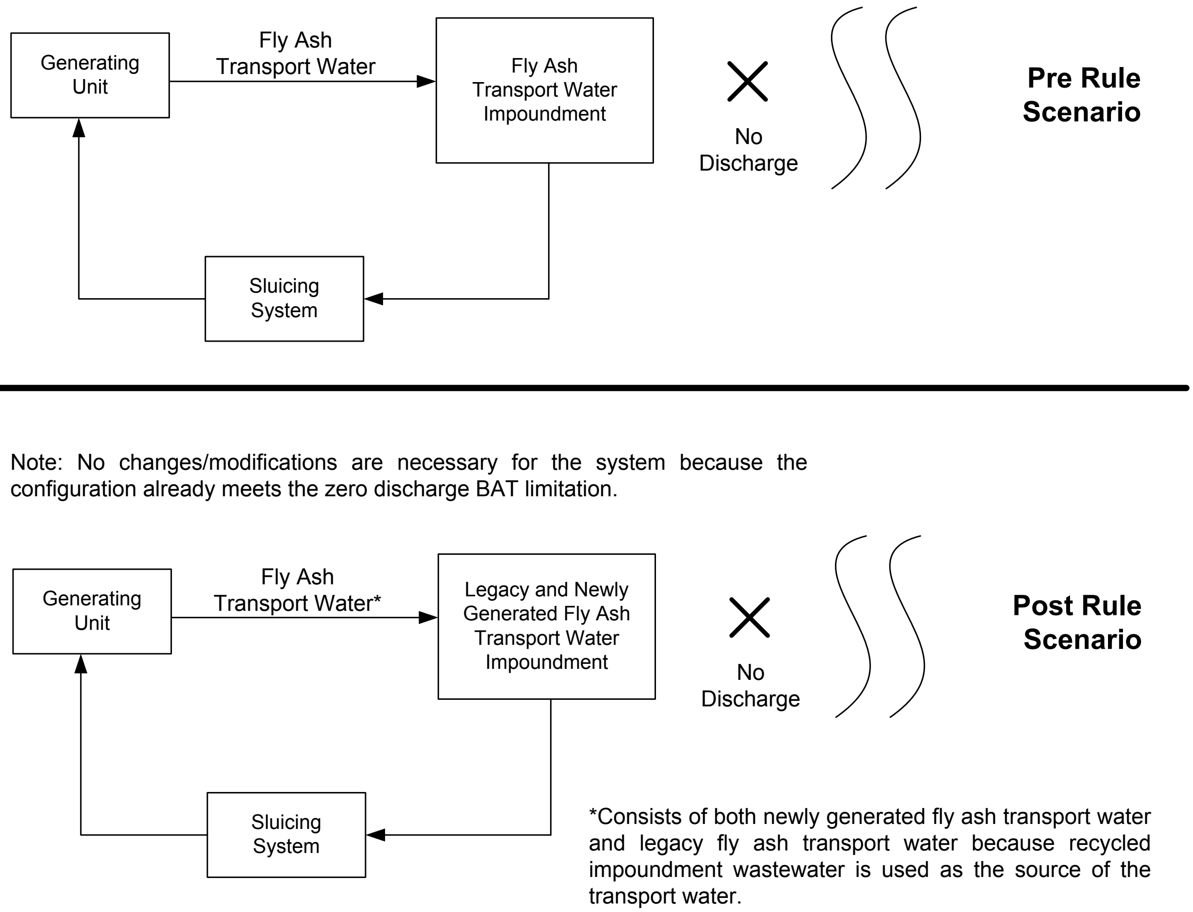

Figure 14-3. Complete Recycle Fly Ash Transport Water Treatment Scenario

Example 14-4: Plant that Currently Discharges Bottom Ash Transport Water

Figure 14-4 presents an example treatment scenario for a plant that operates a partial recycle bottom ash sluicing system in which the plant recycles a majority of the bottom ash transport water for reuse in the sluicing system, but some of the bottom ash transport water is discharged to a receiving water. Under the final rule, the plant will need to meet the new zero discharge BAT limitation for newly generated bottom ash transport water. In this case, EPA envisions that the plant has at least two options for complying with the new limitation, which are included in the post rule scenarios in Figure 14-4. Under post rule *Scenario 1*, the plant would convert to a dry bottom ash handling system, and would not transfer any newly generated bottom ash transport water to the existing impoundment. However, legacy bottom ash transport water could still be discharged from the impoundment (e.g., after a rainfall event, when dewatering the impoundment for closure) and would be subject to the legacy bottom ash transport water BAT limitations (see 40 CFR § 423.13(k)(1)(ii)) and the previously promulgated BPT effluent limitations (see 40 CFR § 423.12(b)(4)) at Monitoring Point Y.

Under post rule *Scenario 2*, the plant would evaluate the water balance for the bottom ash system and determine whether the system could operate without discharging to a receiving water.

If the plant determines that the system can achieve complete recycle, then the plant can continue to operate the existing bottom ash handling system, and ensure that it meets zero discharge (see 40 CFR § 423.13(k)(1)(i)).

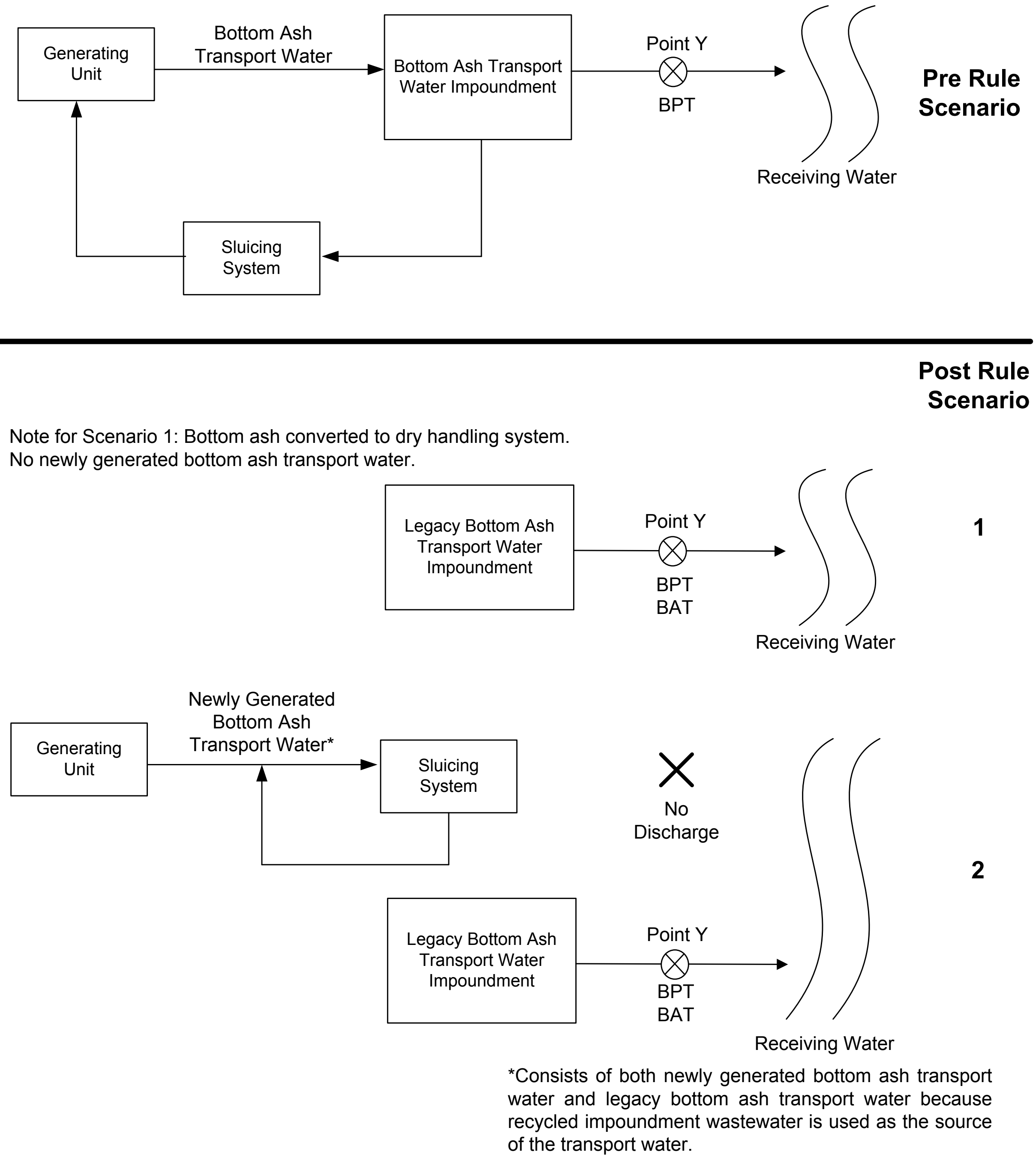

Figure 14-4. Partial Recycle Bottom Ash Transport Water Treatment Scenario

Example 14-5: Plant that Generates Gasification Wastewater

Figure 14-5 presents an example treatment scenario, under the final rule, for an IGCC plant treating and discharging gasification wastewater prior to the implementation of the ELGs (see 40 CFR § 423.12(b)(3)). Under the final rule, the plant will need to meet the new BAT limitations for newly generated gasification wastewater, in which case, EPA envisions that the plant has at least three options for complying with the BAT limitations. These options are included in the post rule scenarios in Figure 14-5. Under post rule *Scenario 1*, the plant would continue to treat and discharge the gasification wastewater, while ensuring it is now meeting the newly promulgated BAT and BPT limitations for gasification wastewater (40 CFR § 423.13(j)(1)(i) and 40 CFR § 423.12(b)(11)).

Under post rule *Scenario 2*, the plant would evaluate the water balance for the gasification process and potentially conclude that the gasification wastewater could be reused completely back into the gasification process without treatment and it would no longer require discharging to a receiving water.

Under post rule *Scenario 3*, the plant would evaluate the water balance for the gasification process and potentially conclude that some of the gasification wastewater could be reused (with or without treatment) back into the gasification process; however, the plant would still require discharging gasification water to a receiving water. In this case, the plant would continue to treat and discharge the gasification wastewater, while ensuring it was now meeting the newly promulgated limitations (see 40 CFR § 423.13(j)(1)(i) and 40 CFR § 423.12(b)(11)).

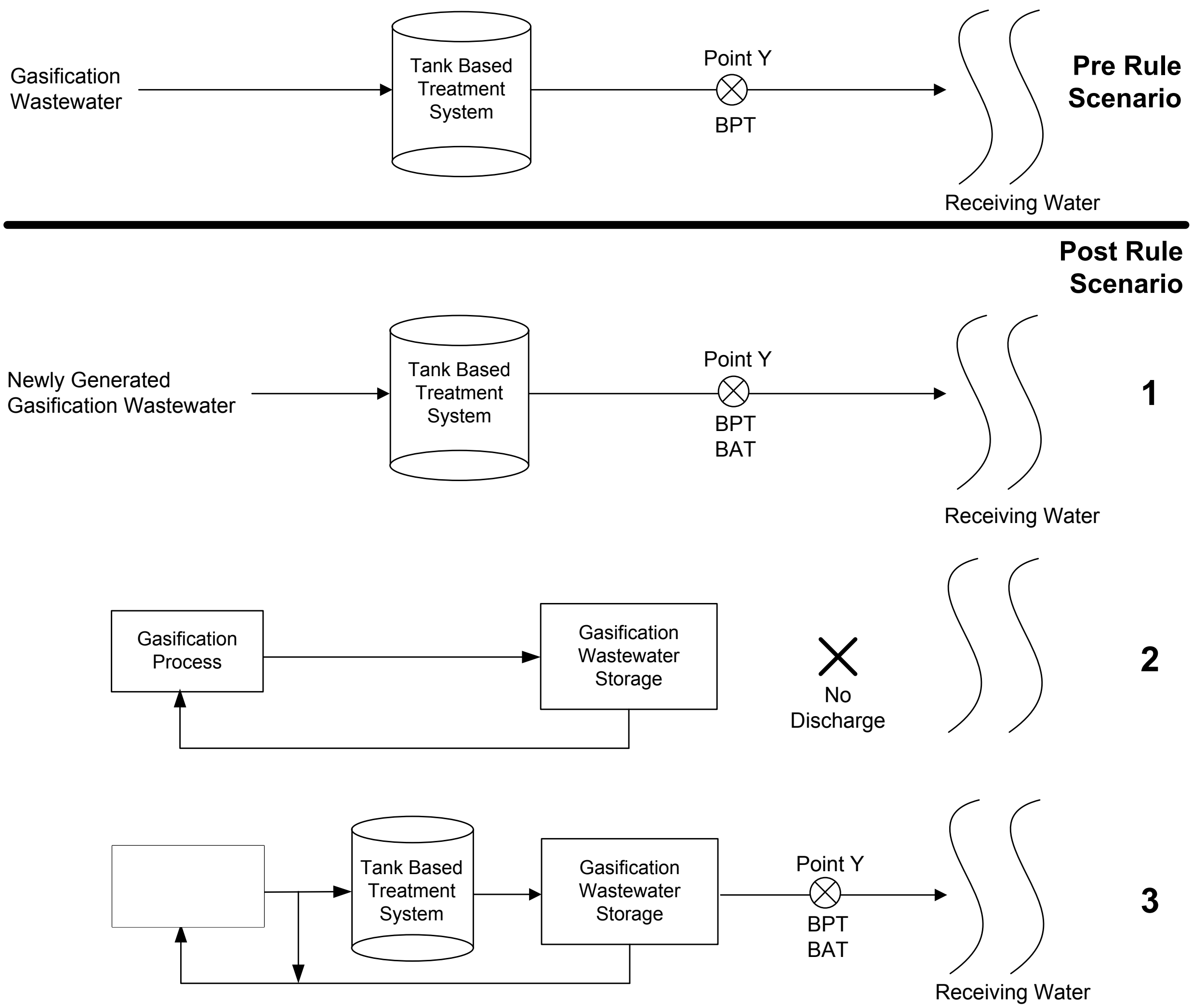

Figure 14-5. Gasification Wastewater Treatment Scenario

Example 14-6: Plant that Generates Combustion Residual Leachate and FGD Wastewater

Figure 14-6 presents an example treatment scenario, under the final rule, for an impoundment that receives combustion residual leachate and FGD wastewater prior to the implementation of the ELGs (see 40 CFR § 423.12(b)(3)). Under the final rule, the plant will need to meet the new BAT effluent limitations for the newly generated FGD wastewater. EPA envisions that the plant has at least two options, which are included in the post rule scenarios in Figure 14-6. Under post rule *Scenario 1*, the plant transfers the newly generated FGD wastewater to a tank-based system and discharges directly from the tank-based system to the receiving water. In this case, the plant would be required to demonstrate compliance with the new BAT and BPT effluent limitations for the newly generated FGD wastewater at the effluent from the tank-based treatment system at Monitoring Point Z (see 40 CFR § 423.12(b)(11) and 40 CFR § 423.13(g)(1)(i)). Additionally, the plant would continue to treat and discharge wastewater from the surface impoundment which would consist of combustion residual leachate and legacy

FGD wastewater, while ensuring it was meeting the newly promulgated BPT and BAT limitations for combustion residual leachate and legacy FGD wastewater(see 40 CFR § 423.13(l) and 40 CFR § 423.12(b)(11)) at Monitoring Point Y. Because the legacy FGD wastewater and the combustion residual leachate are subject to the same limitations, the permit could specify that the plant monitor for compliance with the BPT TSS and oil and grease effluent limitations for the combined wastestream at the point of discharge (Monitoring Point Y).

Under post rule *Scenario 2*, the plant would continue to discharge legacy wastewater and legacy combustion residual leachate from the surface impoundment and comply in the same manner as in *Scenario 1*. Additionally, the plant would combine newly generated combustion residual leachate with newly generated FGD wastewater in the tank-based system. As described in Section 14.1.4 and similar to *Scenario 2a* in Example 14-1, in this case, the permit may specify monitoring for compliance for the combined wastestream at the point of discharge (Monitoring Point Z) using the building block approach, as applicable. For the legacy FGD wastewater and legacy combustion residual leachate contained in the impoundment, the permit could specify that the plant monitor for compliance with the BPT TSS and oil and grease effluent limitations for the combined wastestream in the impoundment effluent (Monitoring Point Y) because the legacy FGD wastewater and the legacy combustion residual leachate are subject to the same limitations.

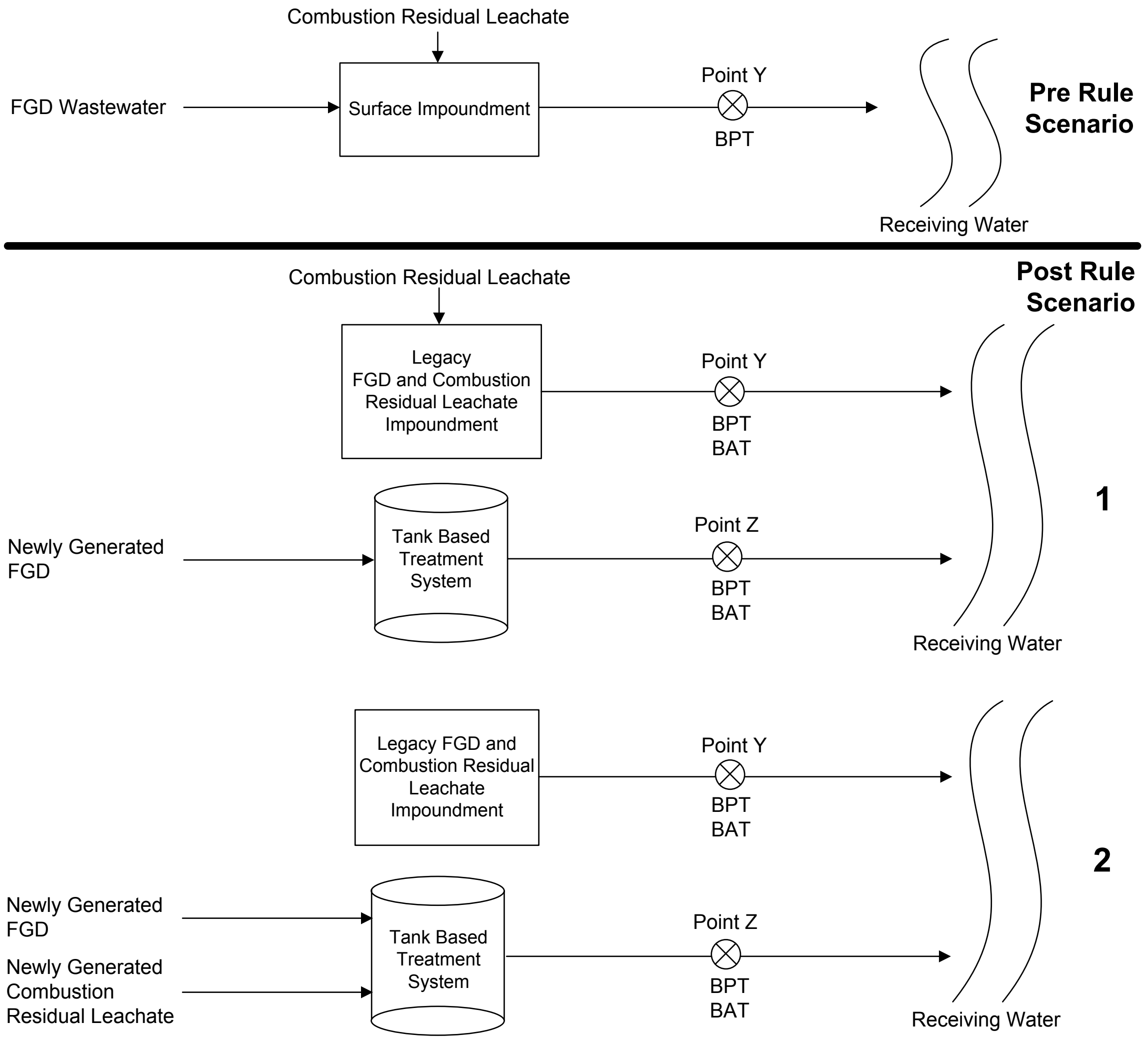

Figure 14-6. Legacy Combustion Residual Leachate Scenario

Example 14-7: Implementation of Size Threshold

Under the final rule, EPA is setting different requirements for discharges of FGD wastewater, fly ash transport water, FGMC wastewater, bottom ash transport water, and gasification wastewater from certain generating units. Under BAT, all oil-fired generating units and generating units with a nameplate capacity of 50 MW or less are subject to new BAT limitations that are equal to the previously promulgated BPT effluent limitations (see 40 CFR § 423.12(b)(4)).

For the final rule, there is the potential that some generating units at a plant would need to comply with a "zero discharge" requirement, while other generating units at the plant would only need to comply with the current BPT standards. Figure 14-7 presents an example scenario for a plant that has a generating unit with a nameplate capacity of 50 MW or less and another generating unit with a nameplate capacity of greater than 50 MW that both discharge fly ash transport water. Under the final rule, if the plant continues to wet sluice the fly ash from the generating unit with a nameplate capacity greater than 50 MW, the fly ash transport water for that generating unit must be completely reused in a process that does not ultimately discharge to receiving waters[180], including indirect discharges to POTWs, to be in compliance with the "zero discharge" requirement. Therefore, EPA envisions that the plant will have at least two potential options to comply with the "zero discharge" requirement for the generating unit with a nameplate capacity of greater than 50 MW.

Under post rule *Scenario 1*, EPA envisions that the plant will have installed a dry fly ash handling system on units >50 MW to meet the new zero discharge BAT limitation. However, legacy fly ash transport water as well as newly generated fly ash transport water from units less than or equal to 50 MW could still be discharged from the impoundment and would be subject to the legacy fly ash transport water BAT limitations (see 40 CFR § 423.13(h)(1)(ii)), the fly ash transport water BAT limitations for oil-fired and small generating units (see 40 CFR § 423.13(h)(2)), and the previously established BPT limitations (see 40 CFR § 423.12(b)(4)).

Under post rule *Scenario 2*, the plant would segregate the fly ash transport water for the generating units with a nameplate capacity >50 MW and completely recycle that transport water with the specific unit's wet sluicing system. In this case, they can still discharge the fly ash transport water from the generating units less than or equal to 50 MW nameplate capacity while meeting the fly ash transport water BAT limitations for oil-fired and small generating units (see 40 CFR § 423.13(h)(2)), and the previously established BPT limitations (see 40 CFR § 423.12(b)(4)).

[180] Or be used in the FGD scrubber. See Section VIII.G of the final preamble.

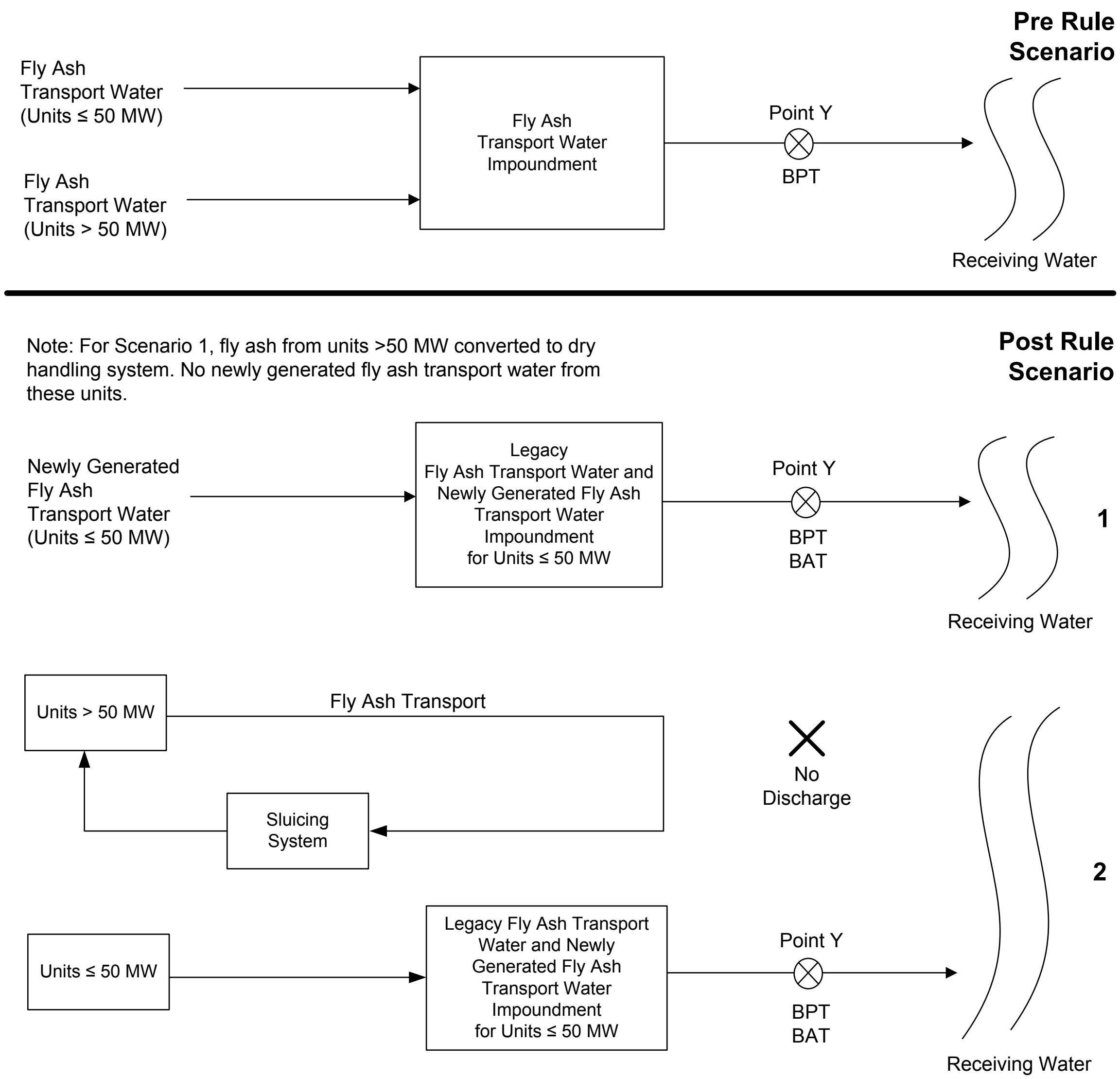

Figure 14-7. Implementation of Size Threshold

Example 14-8: Application of the Building Block Approach; FGD Wastewater with Cooling Water

This example evaluates a plant that currently uses an impoundment to treat its FGD wastewater. Additionally, the plant operates a recirculating cooling water system and the cooling tower blowdown is transferred to an impoundment that receives only cooling tower blowdown. The plant currently combines the discharge from both impoundments and measures for compliance with the previously established BPT limitations at the combined point of discharge. The average FGD wastewater discharge flow rate is 1.2 MGD. The average overflow from the cooling tower blowdown impoundment is 113 MGD. The plant currently combines the overflow from the two impoundments and measures for compliance with the previously established limitations at the discharge point. The plant wants to continue to commingle the two wastestreams prior to monitoring for compliance. In applying the building block approach, EPA expects that because the cooling tower blowdown has the potential to have a dilution effect this flow will likely be treated as a dilution flow. The following shows the calculation of the combined Monthly BAT Limit for arsenic using the building block approach:

$$Combined\ Monthly\ Arsenic\ BAT\ Limitation = \frac{(1.2\ MG) \times \left(8\frac{ug}{L}\right) + (113\ MG) \times (0\frac{ug}{L})}{(1.2\ MGD) + (113\ MGD)}$$

Table 14-9 shows the application of the building block approach for each pollutant regulated in FGD wastewater discharges on or after the as soon as possible date. If the combined limitation for any pollutant falls below the detection limit for that pollutant, then the plant would not be able to demonstrate compliance with the limit and thus EPA recommends measuring for compliance prior to combining with the cooling water effluent. See 40 CFR 122.46(h). As shown in Table 14-9 below, after applying the building block approach, the combined limitation for all pollutants regulated in FGD wastewater except mercury is below the detection level. Therefore, limitations at the point of discharge would be impracticable, and the permitting authority may impose internal limits to ensure compliance with the BAT FGD limitations.

Table 14-9. Combined Monthly BAT Limitations Using Building Block Approach

Analyte	Cooling Water Allowed Concentration (ug/L)	FGD Wastewater BAT Monthly Limits for Final Rule (ug/L)	Calculated Combined BAT Monthly Limit[a] (ug/L)	Baseline Values for Analytes (ug/L)[b]	Below Detection Limit?
Arsenic	0	8	0.084	2	Yes
Mercury	0	0.356	0.0037	0.0005	No
Nitrate/Nitrite (as N)	0	3,500	36.8	50	Yes
Selenium	0	12	0.126	5	Yes
Total Suspended Solids	0	30,000	315	4,000	Yes
Oil and Grease	0	15,000	158	5,000	Yes

a – EPA estimated the combined effluent concentration assuming that the concentration of each of the pollutants was zero in the cooling tower blowdown.

b – EPA determined the baseline values for mercury and nitrate-nitrite as N using the minimum levels (MLs) established by the analytical methods used to obtain the reported values or a comparable analytical method where an ML was not specified by the method. The baseline values for arsenic and selenium are based on the results of method detection limit (MDL) studies conducted by well-operated commercial laboratories using EPA Method 200.8 to analyze samples of synthetic FGD wastewater. See TDD Section 13.

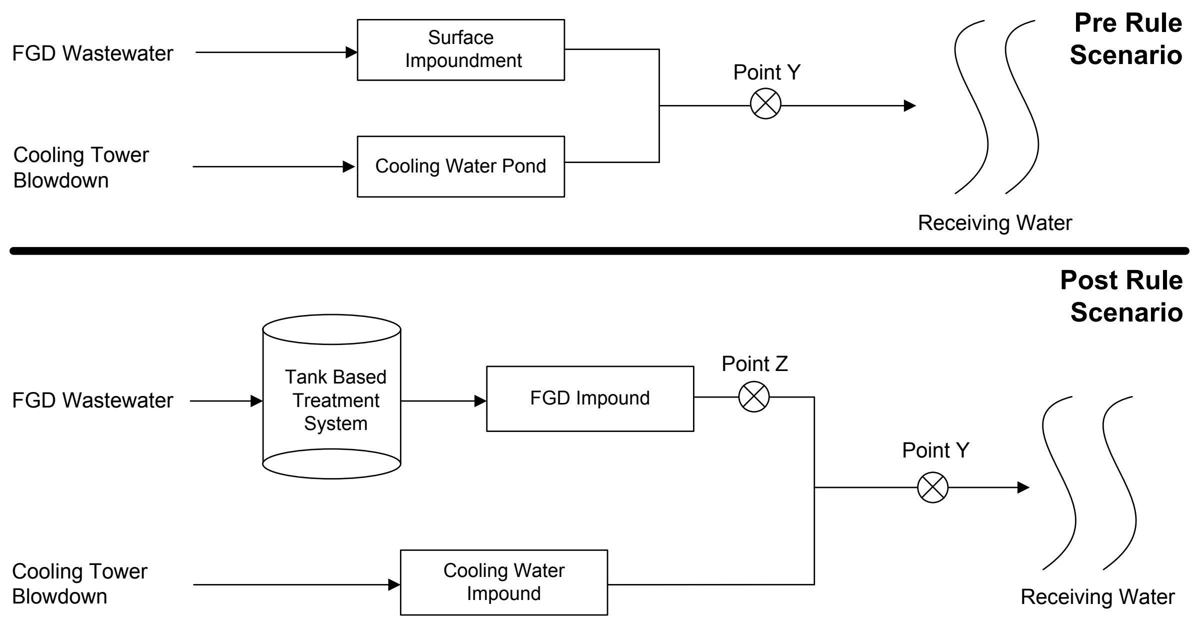

Figure 14-8. Building Block Approach; FGD Wastewater with Cooling Water

Example 14-9: Application of the Building Block Approach; FGD Wastewater with Combustion Residual Leachate

This example evaluates a plant that currently uses an impoundment to treat its FGD wastewater and combustion residual leachate. The average FGD wastewater discharge flow rate is 1.2 MGD. The average combustion residual leachate flow rate is 0.2 MGD. The plant currently measures for compliance with the previously established BPT limitations at the point of discharge from the impoundment (Monitoring Point Y), as shown in Figure 14-9. The plant wants to continue to commingle the two wastestreams prior to monitoring for compliance. The following shows the calculation of the combined Monthly BAT Limit for arsenic using the building block approach:

$$Combined\ Monthly\ Arsenic\ BAT\ Limitation = \frac{(1.2\ MG) \times \left(8\frac{ug}{L}\right) + \ (0.2\ MG) \times (38.4\frac{ug}{L})}{(1.2\ MGD) + \ (0.2\ MGD)}$$

Table 14-10 shows the application of the building block approach for each pollutant regulated in FGD wastewater discharges on or after the as soon as possible date. Because the FGD wastewater contains regulated pollutants that are also present in the combustion residual leachate, but that are not regulated in combustion residual leachate, EPA determined a concentration for each regulated pollutant contributed by the combustion residual leachate. If the combined limitation for any pollutant falls below the detection limit for that pollutant, then the plant would not be able to demonstrate compliance with the limit and thus EPA recommends measuring for compliance prior to combining with the combustion residual leachate (Monitoring Point Z). However, as shown in Table 14-10, after applying the building block approach, the combined limitation for all regulated pollutants is above the detection level. Therefore, limitations at the point of discharge (Monitoring Point Y) would be practicable.

Table 14-10. Combined Monthly BAT Limitations Using Building Block Approach

Analyte	FGD Wastewater BAT Monthly Limits for Final Rule (ug/L)	Combustion Residual Leachate Allowable Concentration[a] (ug/L)	Calculated Combined BAT Monthly Limit[b] (ug/L)	Baseline Values for Analytes (ug/L)[c]	Below Detection Limit?
Arsenic	8	38.4	12.3	2	No
Mercury	0.356	1.06	0.457	0.0005	No
Nitrate/Nitrite (as N)	3,500	NA	3,000	50	No
Selenium	12	111	26.1	5	No
Total Suspended Solids	30,000	30,000[d]	30,000	4,000	No

a – EPA estimated the contribution from combustion residual leachate using data presented in Section 6.

b – EPA estimated the combined effluent concentration for each of the regulated pollutants by using the FGD wastewater BAT limits combined with the contribution in the combustion residual leachate.

c – EPA determined the baseline values for mercury and nitrate-nitrite as N using the minimum levels (MLs) established by the analytical methods used to obtain the reported values or a comparable analytical method where an ML was not specified by the method. The baseline values for arsenic and selenium are based on the results of method detection limit (MDL) studies conducted by well-operated commercial laboratories using EPA Method 200.8 to analyze samples of synthetic FGD wastewater. See TDD Section 13. The baseline value for total suspended solids is from Table 6-1 of the *Development Document for Effluent Limitations Guidelines and Standards for the Centralized Waste Treatment Industry – Final* (EPA 821-R-00-020).

d – Combustion residual leachate BAT Monthly Limits for Final Rule (ug/L).

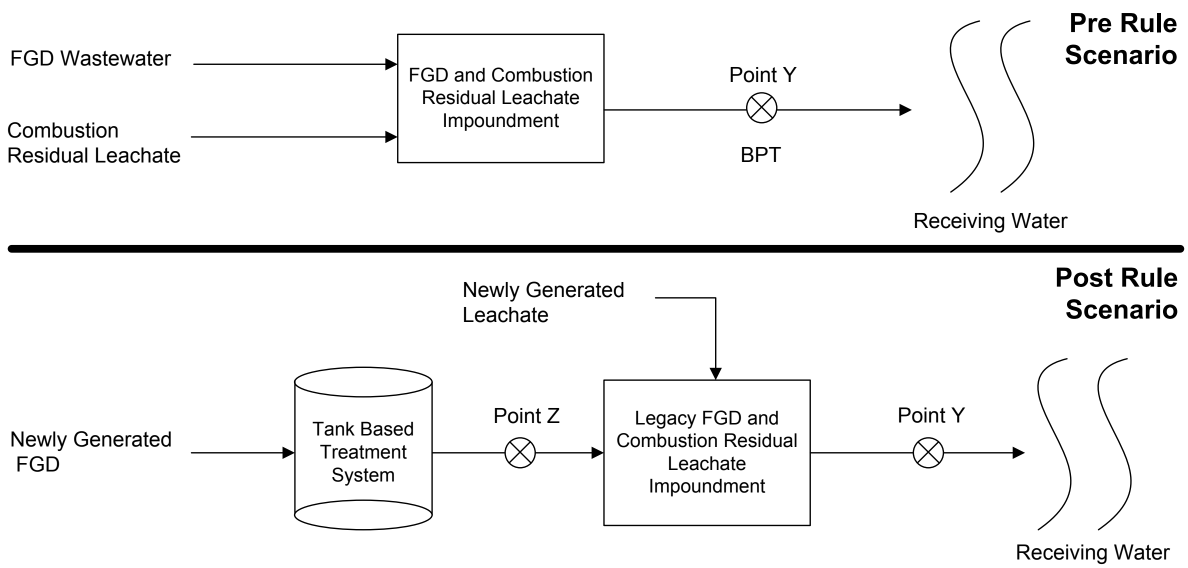

Figure 14-9. Building Block Approach; FGD Wastewater with Combustion Residual Leachate

14.1.7 Monitoring Requirements

The final rule does not establish the location or frequency of the monitoring requirements. NPDES permit regulations at §122.48(b) and pretreatment regulations at §403.12(g) require that permits include monitoring requirements, including frequency, that are sufficient to yield data representative of the regulated activity. Typically, the monitoring frequencies specified in steam electric NPDES permits vary depending upon the size of the plant, potential impacts on receiving waters, compliance history, and other factors, including monitoring policies or regulations required by permit authorities. Also see Chapter 8 of EPA's NPDES Permit Writer's Manual.

14.1.8 Analytical Methods

Section 304(h) of the CWA directs the EPA to promulgate guidelines establishing test procedures (methods) for the analysis of pollutants. These methods are used to determine the presence and concentration of pollutants in wastewater and for compliance monitoring. They are also used for filing applications for the National Pollutant Discharge Elimination System (NPDES) permit program under 40 CFR 122.41(j)(4) and 122.21(g)(7), and under 40 CFR 403.7(d) for the pretreatment program. The EPA has promulgated analytical methods for CWA activities at 40 CFR part 136 for the pollutants for which EPA established new limitations or standards in this final rule.

In some cases, where EPA has promulgated more than one analytical method for a pollutant in 40 CFR part 136, the permittee may use any of these methods. This is not the case for all pollutants regulated in this final rule. In August 2014, EPA published a rule requiring the use of sufficiently sensitive analytical test methods when completing any NPDES permit application. The Director must prescribe that only sufficiently sensitive methods be used for analyses of pollutants or pollutant parameters under an NPDES permit where EPA has promulgated a CWA method for analysis of that pollutant. The rule clarifies that NPDES applicants and permittees must use EPA-approved analytical methods that are capable of detecting and measuring the pollutants at, or below, the applicable water quality criteria or permit limits.

Part 136 recommends that plants use the clean sampling techniques described in EPA's draft method 1669: Sampling Ambient Water for Trace Metals at EPA Water Quality Criteria Levels (EPA-821-R-96-011) for mercury collection for EPA Methods 245.7 and 1631E to prevent contamination at low-level, trace metal determinations. EPA Methods 245.7 and 1631E are the only Part 136-approved methods that have a detection limit low enough to be used for the mercury analysis for the FGD wastewater limit in the final rule. While EPA Methods 245.7, 1631E, and 1669 do not specifically require plants to collect mercury samples as grab samples, EPA recommends that mercury be collected as grab samples because there is less potential for contamination compared to composite sampling. EPA also recommends that mercury samples be collected as four grab samples in a 24-hour monitoring day, and that the results should be averaged to represent a daily sample.

FGD wastewater can contain constituents that may interfere with certain laboratory analyses, due to high concentrations of total dissolved solids (TDS) or the presence of elements known to cause matrix interferences. To address this issue, EPA developed two standard operating procedures (SOPs) that it used in conjunction with EPA Method 200.8 to conduct ICP-MS analyses of FGD wastewater during its sampling activities. The SOPs describe critical technical and quality assurance procedures that EPA implemented to mitigate anticipated interferences and generate reliable data for FGD wastewater. These SOPs represent an approved modification allowed under 40 CFR part 136.6. Others have similarly developed SOPs including EPRI. These SOPs take a proactive approach toward looking for and taking steps to mitigate matrix interferences, including using specialized interference check solutions (i.e., a synthetic FGD wastewater matrix). Consistent with the proposed rule, EPA included its SOPs in the final record for laboratories contemplating ICP-MS analysis of FGD wastewater, either for adoption as currently written or to serve as a framework for developing their own laboratory-specific SOPs.

14.1.9 Non-Chemical Metal Cleaning Wastes

By reserving BAT and NSPS for non-chemical metal cleaning waste in this final rule, the permitting authority must establish such requirements based on BPJ for any steam electric power plant discharging this wastestream. In permitting this wastestream, some permitting authorities have classified it as non-chemical metal cleaning waste (a subset of metal cleaning wastes), while others have classified it as a low volume waste source. These wastestreams have different BPT limitation under the previously established regulation and the specific NPDES permit limitations for this wastestream thus reflect that classification as made by the permitting authority. In making future BPJ BAT determinations, EPA recommends that the permitting authority examine the historical permitting record for the particular plant to determine how discharges of non-chemical metal cleaning wastes have been permitted in the past. Using historical information and its best professional judgment, the permitting authority could determine that the BPJ BAT limitations should be set equal to existing BPT limitations as classified by the permitting authority or it could determine that more stringent BPJ BAT limitations should apply. For example, a permit that includes BPT limits for a low volume waste classification could include BPJ BAT effluent limitations equivalent to BPT for metal cleaning wastes for the non-chemical metal cleaning wastestream. In making a BPJ determination for new sources, EPA recommends that the permitting authority consider whether it would be appropriate to base standards on BPT limitations for metal cleaning wastes or on a technology that achieves greater pollutant reductions.

14.2 Upset and Bypass Provisions

The CWA, the NPDES permit regulations at §122.41(m) and (n), and the pretreatment regulations at §403.16 and §403.17 allow effluent discharges above permit limits under certain exceptional and limited circumstances. A bypass is an intentional diversion of a wastestream from any portion of a treatment facility to prevent unavoidable loss of life, personal injury, or severe property damage. Economic loss caused by delays in production does not constitute severe property damage for the purposes of this regulation. The key requirements for the bypass provisions of a permit are: (1) the bypass must be intentional; (2) prior notice (10 days, if possible) must be provided; and (3) there must be no feasible alternatives to the bypass. A plant does not meet these requirements if it lacks adequate back-up equipment that it should have installed to prevent a bypass during periods of normal operation or maintenance using reasonable engineering judgment. In other cases, intentional bypasses are allowed if required for essential maintenance to ensure efficient operation, as long as these bypasses do not cause the plant to exceed its effluent limitations.

An upset is an exceptional incident in which a facility unintentionally and temporarily cannot comply with its technology-based permit effluent limitations due to factors beyond its reasonable control. An upset does not include noncompliance due to operational error, improperly designed treatment facilities, inadequate treatment facilities, lack of preventative maintenance, or careless or improper operation. A plant can defend a case in which it exceeds its effluent limitations if the permit holder can demonstrate the following: the cause of the upset can be identified, the permitted facility was being properly operated at the time of the upset, and the permit holder made the required 24-hour notification. In any enforcement proceeding, the burden of proof is on the permit holder, through properly signed operating logs or other relevant evidence, to demonstrate an upset has occurred.

Because Section 510 of the CWA authorizes permit authorities to include more stringent controls than those contained in the federal regulations, any bypass and upset provisions must be included in permits issued by permit authorities to become available to permit holders. Permit authorities should anticipate that permit holders with properly designed and operated wastewater treatment systems would have very few, if any, bypasses or upsets in the course of a five-year NPDES permit that meet the above criteria.

14.3 VARIANCES AND MODIFICATIONS

The CWA requires application of effluent limitations established pursuant to Section 301 or the pretreatment standards of Section 307 to all direct and indirect dischargers. However, the statute provides for the modification of these national requirements in a limited number of circumstances. The Agency has established administrative mechanisms to provide an opportunity for relief from the application of the national effluent limitations guidelines for categories of existing sources for toxic, conventional, and nonconventional pollutants.

As opposed to the bypass and upset provisions that are applicable within the term of a permit, the permit writer develops the variance and alternative limitations at the time of draft permit renewal so that the variance and alternative limitations are subject to public review and comment at the same time the entire permit is put on public notice. The variance and alternative limitations remain in effect for the term of a permit, unless the permit writer modifies it prior to expiration.

A permit applicant must meet specific data requirements before a variance is granted. As the term implies, a variance is an unusual situation, and the permit writer should not expect to routinely receive variance requests. The permit writer should consult 40 CFR §124.62 for procedures on making decisions on the different types of variances, which are discussed below.

14.3.1 Fundamentally Different Factors Variances

As explained above, the CWA requires application of the effluent limitations established pursuant to Section 301 or the pretreatment standards of Section 307 to all direct and indirect dischargers. However, the statute provides for the modification of these national requirements in a limited number of circumstances. Moreover, the Agency has established administrative mechanisms to provide an opportunity for relief from the application of national effluent limitations guidelines and pretreatment standards for categories of existing sources for priority, conventional, and nonconventional pollutants.

EPA may develop, with the concurrence of the state, effluent limitations or standards different from the otherwise applicable requirements for an individual existing discharger if it is fundamentally different with respect to factors considered in establishing the effluent limitations or standards applicable to the individual discharger. Such a modification is known as an FDF variance.

EPA, in its initial implementation of the effluent guidelines program, provided for the FDF modifications in regulations, which were variances from the BPT effluent limitations, BAT limitations for toxic and nonconventional pollutants, and BCT limitations for conventional pollutants for direct dischargers. FDF variances for toxic pollutants were challenged judicially and ultimately sustained by the Supreme Court *Chemical Manufacturers Association v. Natural Resources Defense Council*, 470 U.S. 116, 124 (1985).

Subsequently, in the Water Quality Act of 1987, Congress added new CWA Section 301(n). This provision explicitly authorizes modifications of the otherwise applicable BAT effluent limitations, if a discharger is fundamentally different with respect to the factors specified in CWA Section 304 (other than costs) from those considered by EPA in establishing the effluent limitations. CWA Section 301(n) also defined the conditions under which EPA may establish alternative requirements. Under Section 301(n), an application for approval of a FDF variance must be based solely on (1) information submitted during rulemaking raising the factors that are fundamentally different or (2) information the applicant did not have an opportunity to submit. The alternate limitation must be no less stringent than justified by the difference and must not result in markedly more adverse non-water quality environmental impacts than the national limitation.

EPA regulations at 40 CFR Part 125, subpart D, authorizing the regional administrators to establish alternative limitations, further detail the substantive criteria used to evaluate FDF variance requests for direct dischargers. Thus, 40 CFR 125.31(d) identifies six factors (e.g., volume of process wastewater, age and size of a discharger's facility) that may be considered in determining if a discharger is fundamentally different. The Agency must determine whether, based on one or more of these factors, the discharger in question is fundamentally different from the dischargers and factors considered by EPA in developing the nationally applicable effluent guidelines. The regulation also lists four other factors (e.g., inability to install equipment within the time allowed or a discharger's ability to pay) that may not provide a basis for an FDF variance. In addition, under 40 CFR 125.31(b) (3), a request for limitations less stringent than the national limitation may be approved only if compliance with the national limitations would result in either (a) a removal cost wholly out of proportion to the removal cost considered during development of the national limitations, or (b) a non-water quality environmental impact (including energy requirements) fundamentally more adverse than the impact considered during development of the national limits. The legislative history of Section 301(n) underscores the necessity for the FDF variance applicant to establish eligibility for the variance. EPA's regulations at 40 CFR 125.32(b)(1) impose this burden upon the applicant. The applicant must show that the factors relating to the discharge controlled by the applicant's permit that are claimed to be fundamentally different are, in fact, fundamentally different from those factors considered by EPA in establishing the applicable guidelines. In practice, very few FDF variances have been granted for past ELGs. An FDF variance is not available to a new source subject to NSPS. *DuPont v. Train*, 430 U.S. 112 (1977).

14.3.2 Economic Variances

Section 301(c) of the CWA allows a plant to request a variance for nonconventional pollutants from technology-based BAT effluent limitations due to economic factors, at the request of the plant and on a case-by-case basis. There are no implementing regulations for §301(c); rather, variance requests must be made and reviewed based on the statutory language in CWA §301(c). The economic variance may also apply to nonguideline limits in accordance with 40 CFR §122.21(m)(2)(ii). The applicant normally files the request for a variance during the public notice period for the draft permit. Other filing time periods may apply, as specified in 40 CFR §122.21(m)(2). Specific guidance for this type of variance is provided in *Draft Guidance for Application and Review of Section 301(c) Variance Requests*, dated August 21, 1984, available on EPA's Web site at http://www.epa.gov/npdes/pubs/OWM0469.pdf.

The variance application must show that the modified requirements:

- Represent the maximum use of technology within the economic capability of the owner or operator; and
- Result in further progress toward the goal of discharging no process wastewater.

Facilities in industrial categories other than utilities must conduct three financial tests to determine if they are eligible for a 301(c) variance. Generally, EPA will grant a variance only if all three tests indicate that the required pollution control is not economically achievable and the applicant makes the requisite demonstration regarding “reasonable further progress.”

To meet the second requirement for a 301(c) modification, the applicant must at a minimum demonstrate compliance with all applicable BPT limitations and pertinent water quality standards. In addition, the proposed alternative requirements must reasonably improve the applicant’s discharge.

14.3.3 Water Quality Variances

Section 301(g) of the CWA authorizes a variance from BAT effluent guidelines for certain nonconventional pollutants due to localized environmental factors. These pollutants include ammonia, chlorine, color, iron, and total phenols. As this rule does not establish limitations or standards for any of these pollutants, this variance is not applicable to this particular rule.

14.3.4 Net Credits

In some cases, solely because of the level of pollutants in the intake water, plants find it difficult or impossible to meet technology-based limits with BAT/BCT technology. Under certain circumstances, the NPDES regulations allow credit for pollutants in intake water. 40 CFR §122.45(g) establishes the following requirements for net limitations:

- Credit for generic pollutants, such as BOD or TSS, are authorized only where the constituents resulting in the effluent BOD and TSS are similar between the intake water and the discharge;
- Credit is authorized only up to the extent necessary to meet the applicable limitation or standard, with a maximum value equal to the influent concentration;
- Intake water must be taken from the same body of water into which the discharge is made; and
- Net credits do not apply to the discharge of raw water clarifier sludge generated during intake water treatment.

Permit writers are authorized to grant net credits for the quantity of pollutants in the intake water where the applicable ELGs specify that the guidelines are to be applied on a net basis or where the pollution control technology would, if properly installed and operated, meet applicable ELGs in the absence of the pollutants in the intake waters. The final ELGs are to be applied on a gross basis.

14.3.5 Removal Credits

Section 307(b)(1) of the CWA establishes a discretionary program for POTWs to grant "removal credits" to their indirect dischargers. Removal credits are a regulatory mechanism by which industrial users may discharge a pollutant in quantities that exceed what would otherwise be allowed under an applicable categorical pretreatment standard because it has been determined that the POTW to which the industrial user discharges consistently treats the pollutant. EPA has promulgated removal credit regulations as part of its pretreatment regulations. See 40 CFR 403.7. These regulations provide that a POTW may give removal credits if prescribed requirements are met. The POTW must apply to and receive authorization from the Approval Authority. To obtain authorization, the POTW must demonstrate consistent removal of the pollutant for which approval authority is sought. Further, the POTW must have an approved pretreatment program. Finally, the POTW must demonstrate that granting removal credits will not cause the POTW to violate applicable Federal, State and local sewage sludge requirements. 40 CFR 403.7(a)(3).

The United States Court of Appeals for the Third Circuit interpreted the Clean Water Act as requiring EPA to promulgate the comprehensive sewage sludge regulations required by CWA §405(d)(2)(A)(ii) before any removal credits could be authorized. *See NRDC v. EPA*, 790 F.2d 289, 292 (3d Cir., 1986); cert. denied., 479 U.S. 1084 (1987). Congress made this explicit in the Water Quality Act of 1987, which provided that EPA could not authorize any removal credits until it issued the sewage sludge use and disposal regulations. On February 19, 1993, EPA promulgated Standards for the Use or Disposal of Sewage Sludge, which are codified at 40 CFR Part 503 (58 FR 9248). EPA interprets the Court's decision in *NRDC v. EPA* as only allowing removal credits for a pollutant if EPA has either regulated the pollutant in part 503 or established a concentration of the pollutant in sewage sludge below which public health and the environment are protected when sewage sludge is used or disposed.

The Part 503 sewage sludge regulations allow four options for sewage sludge disposal: (1) land application for beneficial use, (2) placement on a surface disposal unit, (3) firing in a sewage sludge incinerator, and (4) disposal in a landfill which complies with the municipal solid waste landfill criteria in 40 CFR Part 258. Because pollutants in sewage sludge are regulated differently depending upon the use or disposal method selected, under EPA's pretreatment regulations the availability of a removal credit for a particular pollutant is linked to the POTW's method of using or disposing of its sewage sludge. The regulations provide that removal credits may be potentially available for the following situations:

1. If POTW applies its sewage sludge to the land for beneficial uses, disposes of it in a surface disposal unit, or incinerates it in a sewage sludge incinerator, removal credits may be available for the pollutants for which EPA has established limits in 40 CFR Part 503. EPA has set ceiling limitations for nine metals in sludge that is land applied, three metals in sludge that is placed on a surface disposal unit, and seven metals and 57 organic pollutants in sludge that is incinerated in a sewage sludge incinerator. 40 CFR 403.7(a)(3)(iv)(A).
2. Additional removal credits may be available for sewage sludge that is land applied, placed in a surface disposal unit, or incinerated in a sewage sludge incinerator, so long as the concentration of these pollutants in sludge do not exceed concentration levels established in Part 403, Appendix G, Table II. For sewage sludge that is land applied, removal credits may be available for an additional two metals and 14 organic pollutants. For sewage sludge that is placed on a surface disposal unit, removal credits may be available for an additional seven metals and 13 organic pollutants. For sewage sludge that is incinerated in a sewage sludge incinerator, removal credits may be available for three other metals 40 CFR 403.7(a)(3)(iv)(B).
3. When a POTW disposes of its sewage sludge in a municipal solid waste landfill that meets the criteria of 40 CFR Part 258, removal credits may be available for any pollutant in the POTW's sewage sludge. 40 CFR 403.7(a)(3)(iv)(C).

14.4 SITE-SPECIFIC WATER QUALITY-BASED EFFLUENT LIMITATIONS

Depending on site-specific conditions and applicable state water quality standards, it may be appropriate for permitting authorities to establish water quality-based effluent limitations on bromide, especially where steam electric power plants are located upstream from drinking water intakes.

Bromides (a component of TDS) are not directly controlled by the numeric effluent limitations and standards for existing sources under this final rule (although they would be controlled by the NSPS/PSNS for new sources and by the BAT effluent limitations for existing sources who choose to participate in the voluntary program and are subject to the final FGD wastewater limitations based on use of evaporation technology).

Bromide discharges from coal-fired steam electric power plants can occur because bromide is naturally found in coal and is released as particulates when the coal is burned, or by the addition of bromide compounds to the coal prior to burning, or to the flue gas scrubbing process, to reduce the amount of mercury air pollution that is also created when coal is burned.

While bromide itself is not thought to be toxic at levels present in the environment, its reaction with other constituents in water may be a cause for concern now and into the future. The bromide ion in water can form brominated DBPs when drinking water plants treat the incoming source water using certain disinfection processes including chlorination and ozonation. Bromide can react with the ozone, chlorine, or chlorine-based disinfectants to form bromate and brominated and mixed chloro-bromo DBPs, such as trihalomethanes (THMs) or haloacetic acids (HAAs) (see DCN SE01920). Studies indicate that exposure to THMs and other DBPs from chlorinated water is associated with human bladder cancer (see DCN SE01981 and DCN SE01983). EPA has established the following MCLs for DBPs:

- 0.010 mg/L for bromate due to increased cancer risk from long-term exposure;
- 0.060 for HAAs due to increased cancer risk from long-term exposure; and
- 0.080 mg/L for TTHMs due to increased cancer risk and liver, kidney or central nervous system problems from long-term exposure (see DCN SE01909).

The record indicates that steam electric power plant FGD wastewater discharges occur near more than 100 public drinking water intakes on rivers and other waterbodies, and there is evidence that these discharges are already having adverse effects on the quality of drinking water sources. A 2014 study by McTigue et. al. identified four drinking water treatment plants that experienced increased levels of bromide in their source water, and corresponding increases in the formation of brominated DBPs, after the installation of wet FGD scrubbers at upstream steam electric power plants (see DCN SE04503).

Drinking water utilities are concerned as well, noting that the bromide concentrations have made it increasingly difficult for them to meet SDWA requirements for total trihalomethanes (TTHMs) (see DCN SE01949). And, bromide loadings into surface waters from coal-fired steam electric power plants could potentially increase in the future as more plant operators use bromide addition to improve the control of mercury emissions. The American Water Works Association requested that EPA "instruct NPDES permit writers to adequately consider downstream drinking water supplies in establishing permit requirements for power plant discharges" and take other steps to limit adverse consequences for downstream drinking water treatment plants. EPA agrees that permitting authorities should carefully consider whether water quality-based effluent limitations on bromide or TDS would be appropriate for FGD wastewater discharges from steam electric power plants upstream of drinking water intakes.

EPA regulations at 40 CFR § 122.44(d)(1) require that each NPDES permit shall include any requirements, in addition to or more stringent than effluent limitations guidelines or standards promulgated pursuant to Sections 301, 304, 306, 307, 318 and 405 of the CWA, necessary to achieve water quality standards established under Section 303 of the CWA, including state narrative criteria for water quality. Furthermore, those same regulations require that limitations must control all pollutants, or pollutant parameters (either conventional, nonconventional, or toxic pollutants) which the Director determines are or may be discharged at a level which will cause, have the reasonable potential to cause, or contribute to an excursion above any state water quality standard, including state narrative criteria for water quality.

Where the DBP problem described above may be present, water quality-based effluent limitations for steam electric power plant discharges may be required under the regulations at 40

CFR § 122.44(d)(1), where necessary to meet either numeric criteria (e.g., for bromide, TDS or conductivity) or narrative criteria in state water quality standards. All states have narrative water quality criteria that are designed to prevent contamination and other adverse impacts to the states' surface waters. These are often referred to as "free from" standards. For example, a state narrative water quality criterion for protecting drinking water sources may require discharges to protect people from adverse exposure to chemicals via drinking water. These narrative criteria may be used to develop water quality-based effluent limitations on a site-specific basis for the discharge of pollutants that impact drinking water sources, such as bromide.

To translate state narrative water quality criteria and inform the development of a water quality-based limitation for bromide, it may be appropriate for permitting authorities to use EPA's established MCLs for DBPs in drinking water because the presence of bromides in drinking water can result in exceedances of drinking water MCLs as a result of interactions during drinking water treatment and disinfection processes. The limitation would be developed for the purpose of attaining and maintaining the state's applicable narrative water quality criterion or criteria and protecting the state's designated use(s), including the protection of human health. See 40 CFR § 122.44(d)(1)(vi).

For the reasons described above, during development of the NPDES permit for the steam electric power plant, the permitting authority should provide notification to any downstream drinking water treatment plants of the discharge of bromide. EPA recommends that the permitting authority collaborate with drinking water utilities and their regulators to determine what concentration of bromides at the PWS intake is needed to ensure that levels of bromate and DPBs do not exceed applicable MCLs. The maximum level of bromide in source waters at the intake that does not result in an exceedance of the MCL for DBPs is the numeric interpretation o the narrative criterion for protection of human health and may vary depending on the treatment processes employed at the drinking water treatment facility. The permitting authority would then determine the level of bromide that may be discharged from the steam electric power plant, taking into account other sources of bromide that may occur, such that the level of bromide downstream at the intake to the drinking water utility is below a level that would result in an exceedances of the applicable MCLs for DBPs. In addition, applicants for NPDES permits must, as part of their permit application, indicate whether they know or have reason to believe that conventional and/or nonconventional pollutants listed in Table IV of Appendix D to 40 CFR part 122, (which includes bromide), are discharged from each outfall. For every pollutant in Table IV of Appendix D discharged which is not limited in an applicable effluent limitations guideline, the applicant must either report quantitative data or briefly describe the reasons the pollutant is expected to be discharged as set forth in 40 CFR § 122.2l(g)(7)(vi)(A), made applicable to the States at 40 CFR § 123.25(a)(4).

In addition to requiring the permit applicant to provide a complete application, including proper wastewater characterization, when issuing the permit, the permitting authority can incorporate appropriate monitoring and reporting requirements, as authorized under Section 402(a)(2), 33 U.S.C. 1342(a)(2), and implementing regulations at 40 CFR §§ 122.48, 122.44(i), 122.43 and 122.41(1)(4). These requirements apply to all dischargers and include plants that have identified the presence of bromide in effluent in significant quantities and that are in proximity to downstream water treatment plants.

14.5 REFERENCES

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Appendix A

SURVEY DESIGN AND CALCULATION OF NATIONAL ESTIMATES

Appendix A: Survey Design and Calculation of National Estimates

In June 2010, EPA distributed a survey, entitled The Questionnaire for the Steam Electric Power Generating Effluent Guidelines, to 733 steam electric power plants. The survey was designed to collect technical information related to wastewater generation and treatment, and economic information such as costs of wastewater treatment technologies and financial characteristics of affected companies.

Section A.1 of this appendix describes the survey design, and Section A.2 provides a summary of the survey responses. Section A.3 discusses the weighting procedures, while Section A.4 discusses the calculation of national estimates and variance estimation.

A.1 Survey Design

This section describes the development of the sample frame, stratification factors, sample design and selection, and the targeted level of precision.

A.1.1 Sample Frame

The sample frame for the Steam Electric Survey is a list of steam electric power generating plants subject to the steam electric power generating effluent guidelines. In addition to listing population elements in terms of contact information (address, phone number, etc.), other information in a sample frame was also used to design the survey.

For this survey, EPA considered the target population to be all fossil- and nuclear-fueled steam electric power plants in the U.S. that report as operating under North American Industry Classification System (NAICS) code 22. EPA constructed the sampling frame using databases that are maintained by the Energy Information Administration (EIA), a statistical agency of the U.S. Department of Energy (DOE), and supplemented it with additional information compiled by EPA. The primary source of information was the 2007 Electric Generator Report (Form EIA-860). Supplemental information was found in Form EIA-923 and in a survey conducted by EPA's Office of Resource Conservation and Recovery. In addition, EPA identified several facilities that started operations after 2007 and obtained necessary information for them.

Using these sources of information, EPA compiled a sample frame containing information on 1,197 steam electric power plants with a total of 2,571 generating units that were within the scope of the survey.

A.1.2 Plant Fuel Classification: the Main Stratification Variable

For this survey, the plant is the sampling unit. EPA stratified the sample frame based on the plant fuel classification, which was determined by the type of fuel used by each of the generating units in operation at the plant. EPA classified each plant's fuel type in the sample frame using the following hierarchical structure:

First, plants were identified as coal plants if the plant had one or more generating units that used coal as its primary or secondary fuel. Since the integrated gasification combined cycle (IGCC) units used coal as the fuel source, they were classified as coal plants.

Second, plants were identified as petroleum coke plants if the plant had one or more generating units that used petroleum coke as its primary or secondary fuel (and the plant was not already classified as a coal plant);

Third, among the remaining plants, those plants for which all units used the same primary fuel type were classified as follows:

- Gas: all units used gas as the primary fuel type, but did not use combined cycle steam turbines;
- Gas-Combined Cycle (CC): all units used gas as the primary fuel type and each used combined cycle steam turbines;
- Oil: all units used oil as the primary fuel type;
- Nuclear: all units were nuclear-fueled;

Finally, all remaining plants with generating units having different fuel types were classified as combination plants as follows:

- Combination - Gas and Gas-CC;
- Combination - Gas and Oil;
- Combination - Gas-CC and Oil;
- Combination - Gas, Gas-CC, and Oil;
- Combination - Gas-CC, Nuclear, and Oil.

A.1.3 Sample Design

The basic sample design of the survey was a stratified design of the plants. The first stratification variable was the plant fuel classification as defined in subsection A.1.2. The second stratification variable was regulatory status, by which each plant was classified as regulated or unregulated. The questionnaire included questions about generating units, and each selected plant was required to complete the questionnaire for every generating unit at the plant.

Another candidate variable for stratification was North American Electric Reliability Corporation (NERC) region but it was not used as a stratification variable. Instead it was used as a sorting variable in systematic sampling to ensure the sample be spread evenly by NERC region; stratum members were sorted by NERC region and every k^{th} member was selected (where k is the ratio of the stratum population size to the stratum sample size). As a result of this systematic sampling, the percentage representation of each NERC region in the sample was expected to be proportional to the size of the region in the population.

All coal and petroleum coke plants were taken with certainty (*i.e.*, all plants in the stratum were selected), whereas for other strata, the sampling rate was 30 percent with a minimum sample size constraint of 10. Therefore, if a stratum population size was less than 34, 10 plants were selected systematically or all plants if there were not more than 10 plants. Due to this constraint, most combination strata were taken with certainty. Table A-1 presents the distribution of the sample frame (plants and generating units) and sample allocation of the plants by design stratum.

Table A-1. Population Distribution of Plants and Generating Units, and Plant Sample Size by Design Stratum

Plant Fuel Classification	Regulatory Status	Sample Frame		Sample
		Plant	Generating Unit	Plant
Coal	Regulated	344	963	344
	Unregulated	151	340	151
Gas	Regulated	129	310	39
	Unregulated	54	137	16
Gas-Combined Cycle (CC)	Regulated	96	129	29
	Unregulated	276	375	83
Nuclear	Regulated	31	52	10
	Unregulated	32	48	10
Oil	Regulated	23	55	10
	Unregulated	20	38	10
Petroleum Coke	Regulated	0	0	0
	Unregulated	9	9	9
Combination: Gas-CC and Nuclear and Oil	Regulated	1	5	1
	Unregulated	0	0	0
Combination: Gas-CC and Oil	Regulated	2	6	2
	Unregulated	0	0	0
Combination: Gas and Gas-CC	Regulated	20	69	10
	Unregulated	6	23	6
Combination: Gas and Gas-CC and Oil	Regulated	1	4	1
	Unregulated	0	0	0
Combination: Gas and Oil	Regulated	1	4	1
	Unregulated	1	4	1
Total		**1,197**	**2,571**	**733**

The exact number of generating units from these 733 plants to be selected was not known prior to the sample draw because the number of generating units varies by plant and thus would depend on the specific set of plants selected. EPA estimated that about 1,722 generating units would be included in the survey from these 733 plants. This estimated number of generating units was arrived at in the following manner. Generating units within plants that are selected with certainty will automatically be included in the sample. For each non-certainty stratum, EPA estimated the corresponding number of generating units by assuming that the rate of generating units per plant in the sample will be the same as the rate among plants in the sampling frame.

A.1.4 Subsample of Coal and Petroleum Coke Plants for Questionnaire Parts E, F, and G

A subsample of coal and petroleum coke plants was selected to receive additional questions in Parts E, F, and G of the questionnaire. To minimize the burden on small entities, EPA did not collect this additional information from plants that were operated by small entities. Of the 495 coal plants, 55 of these were identified as small entities. The remaining 440 non-small (*i.e.*, not owned by small entities) coal plants were further stratified by whether the plant had a pond or a landfill for waste management as EPA intended to collect information from plants that had ponds and/or landfills containing coal combustion residues (*i.e.*, coal ash or flue gas desulfurization (FGD) wastes). Thus, plants that were classified as “No ponds or landfills” were excluded from subsampling for Parts E, F, and G.

Strata defined by pond-landfill status are as follows:

- *Pond Only – FGD:* Contained all coal plants identified in the sample frame as having a pond with FGD waste as one of its contents, but not a landfill;
- *Pond Only – No FGD:* Contained all coal plants with an ash pond that does not receive FGD waste, but without landfill;
- *Landfill Only – FGD:* Contained all coal plants that had a landfill with FGD waste as one of its contents, but no pond containing coal combustion residues (CCR);
- *Landfill Only – No FGD:* Contained all coal plants that had a landfill containing ash but without FGD wastes, and did not operate a CCR pond;
- *Ponds and Landfills:* Contained all coal plants that had both ponds and landfills containing CCR (either ash or FGD wastes). To minimize the number of strata, no distinction in plants was made by FGD status; and
- *No Ponds or Landfills:* Contained all coal plants that did not store or dispose ash or FGD wastes in a pond or landfill.

Seven plants known to operate leachate collection systems were selected with certainty because EPA wanted to capture this information fully. EPA excluded two coal plants (containing a total of six generating units) from subsampling to avoid the potential burden imposed on these plants. Other plants were subsampled with a sampling rate of 30 percent or 10 plants, whichever was larger for each stratum listed above.

Table A-2 displays the population counts of coal and petroleum coke plants and the corresponding number of generating units, and the sample size for each stratum defined by business size and pond-landfill status. The total sample size for Parts E, F, and G for the coal plants is 94, of which seven were plants with leachate system selected with certainty (shown in parentheses in Table A-2). All three non-small petroleum coke plants were included in the subsample that received Parts E, F, and G. These plants were not classified by pond-landfill status. Therefore, the total sample size for Parts E, F, and G was 97, which consisted of 94 coal plants and 3 petroleum coke plants.

Table A-2. Population Counts of Coal/Pet Coke Plants and Generating Units, and Parts EFG Subsample Size by Substratum

Plant Fuel Classification	Business Size	Pond/Landfill	Population Count of Plants	Population Count of Generating Units	Sample Size (Certainty Selection) [a]
Coal	Small	All	55	121	0

Table A-2. Population Counts of Coal/Pet Coke Plants and Generating Units, and Parts EFG Subsample Size by Substratum

Plant Fuel Classification	Business Size	Pond/Landfill	Population Count of Plants	Population Count of Generating Units	Sample Size (Certainty Selection) [a]
	Non-Small	Pond Only – FGD	39	122	12 (1)
		Pond Only – No FGD	99	315	30 (0)
		Landfill Only – FGD	18	34	10 (1)
		Landfill Only – No FGD	55	142	17 (3)
		Both Pond and Landfill	84	256	25 (2)
		No Pond or Landfill	143	307	0
		Avoid Burden [b]	2	6	0
Pet Coke	Small	--	6	6	0
	Non-Small	--	3	3	3
Total			**504**	**1,312**	**97 (7)**

a – In parentheses, the number of plants with the leachate system selected with certainty is shown. The sample size includes this number.

b – EPA excluded two coal plants from receiving parts E, F, and G to avoid overburdening these plants.

The exact number of generating units at the 94 coal plants to be selected was not known prior to the sample draw because the number of generating units varies by plant and thus would depend on the specific set of coal plants selected. Prior to selecting the sample of coal plants, EPA estimated that about 272 generating units at these 94 coal plants would be included in the survey. In addition, there were three petroleum coke generating units (from three plants) that were selected with certainty. Thus, it was expected that there would be about 275 generating units from these 97 plants that would be included in the subsample.

A.1.5 Sample Selection

The regular sample that received the questionnaire without Parts E, F, and G was selected according to the sample design described in subsection A.1.3, resulting in 733 sample plants. The majority of the strata were sampled with certainty by design or the constraint of minimum sample size of 10 if possible. Because of this minimum sample size constraint, almost all combination fuel type strata were certainty strata.

The coal and petroleum coke plants were selected with certainty in the regular sample by design but only a subsample of 97 was selected by a stratified design to receive Parts E, F, and G of the questionnaire. This subsample is called the Parts EFG subsample. The sample results are summarized in Table A-3. The table also presents the base weights, which are the inverse of the sampling probability.

Table A-3. Summary of Sample Selection of Plants

Stratum/Coal Substratum	Population Size	Regular Sample		Subsample	
		Size	Base Weight	Size	Base Weight [a]
Coal – Small Entity	55	55	1	-	
Coal – Pond Only –FGD	39	39	1	12	3.45
Coal – Pond Only –no FGD	101 [b]	101	1	30	3.37
Coal – Landfill Only – FGD	18	18	1	10	1.89
Coal – Landfill Only – No FGD	55	55	1	17	3.71
Coal – Both Pond and Landfill	84	84	1	25	3.57
Coal – No Pond and Landfill	143	143	1	-	-
Coal Subtotal	**495**	**495**	**-**	**94**	
Gas-Regulated	129	39	3.31	-	-
Gas-Unregulated	54	16	3.38	-	-
Gas-CC-Regulated	96	29	3.31	-	-
Gas-CC-Unregulated	276	83	3.33	-	-
Nuclear-Regulated	31	10	3.1	-	-
Nuclear-Unregulated	32	10	3.2	-	-
Oil-Regulated	23	10	2.3	-	-
Oil-Unregulated	20	10	2	-	-
Petroleum Coke-Unregulated/Small Entity	6	6	1	-	-
Petroleum Coke-Unregulated/Non-small	3	3	1	3	1
Combination: Gas-CC, Nuclear, and Oil-Regulated	1	1	1	-	-
Combination: Gas-CC and Oil-Regulated	2	2	1	-	-
Combination: Gas and Gas-CC-Regulated	20	10	2	-	-
Combination: Gas and Gas-CC-Unregulated	6	6	1	-	-
Combination: Gas, Gas-CC and Oil-Regulated	1	1	1	-	-
Combination: Gas and Oil-Regulated	1	1	1	-	-
Combination: Gas and Oil-Unregulated	1	1	1	-	-
Non-Coal Subtotal	**702**	**238**	**-**	**3**	**-**
Grand Total	**1,197**	**733**	**-**	**97**	**-**

a – The subsample base weights are for non-certainty coal plants or for certainty petroleum coke plants.

b – This count includes two plants that were not subsampled due to burden consideration.

A.1.6 Expected Precision

An expected precision is usually calculated for a population proportion of 50 percent. Assuming a response rate of 90 percent, the final sample size for the regular sample was expected to be 660 (*i.e.*, 90 percent of the 733 sampled plants). To calculate an expected precision, a design effect of one was assumed, and the finite population correction was ignored to be conservative. The stratification would decrease the design effect but weighting adjustment for nonresponse would increase the design effect. So we assumed that these two effects would cancel each other to make the design effect close to one. Under this scenario, the 95 percent confidence interval for a point estimate of a population proportion of 50 percent was expected to be within ± 3.8 percentage points of the point estimate. If we project the precision for a population proportion of 30 percent, the 95 percent confidence interval would be within ± 3.5 percentage points.

For the subsample of the coal plants for the Parts E, F, and G questionnaire, under the same assumption, it was estimated to have an expected sample size of 85 from the subsample of 94 coal plants. The 95 percent confidence interval for a point estimate of a population proportion of 30 percent was expected to be within +/- 9.2 percentage points of the point estimate.

For generating unit level estimates, under the same assumption made above and further ignoring the clustering effect, the final sample size was expected to be 1,550 (*i.e.*, 90 percent of the expected number of generating units of 1,722 in the sample), and the 95 percent confidence interval for a point estimate of a population proportion of 50 percent was expected to be within +/- 2.5 percentage points of the point estimate.

EPA determined that these precisions were sufficient to meet the objectives of the survey, both for overall plant-level and generating unit level estimates. Moreover, the actual precision is expected to be better than the projected precision when the finite population correlation is incorporation. Furthermore, the plant level response rate was 100 percent, which further adds more precision than projected.

A.2 Survey Responses

Of the 733 survey questionnaires sent out, all were returned, so the plant level response rate was 100 percent. However, the survey responses indicate that the frame information on plant eligibility, plant fuel classification, and pond-landfill status for coal and petroleum coke plants was imperfect. The following subsections provide updated information on the eligibility assessment, plant classifications, and pond-landfill classification.

A.2.1 Survey Result of the Eligibility Assessment

Out of 733 respondent plants, a total of 53 plants were found to be ineligible (*i.e.*, out of scope). The reasons for the ineligibility include the following: plant did not have the capability to engage in steam electric power production; plant would be retired by December 31, 2011; or plant did not generate electricity in 2009 using any fossil or nuclear fuels. Of these 53 plants that were deemed ineligible, the distribution over the plants fuel types is as follows: 26 coal plants, 17 gas plants, 6 gas-combined cycle plants, 2 oil plants, 1 petroleum coke plant, and 1 combination plant. To see the distribution of these ineligible plants further classified by regulatory status, see Table A-6 in Section A.3.1, where the number of eligible plants is shown and the number of ineligible plants can be obtained by the balance between the original sample size and the number of eligible plants.

A.2.2 Update of Plant Fuel Type Classification

At the survey design stage, plant fuel type was classified based on the EIA data and other information available to the EPA. After receiving the survey responses, EPA reclassified the sampled plant fuel types using the information from the questionnaire. EPA found that 17 of 680 eligible plants had a fuel type that was different from the original plant fuel type determined at the design stage. The table below provides the final plant fuel classification for all 680 eligible sampled plants based on the survey data.

Table A-4. Final Eligible Sampled Plant Fuel Types

Final Plant Fuel Type (Classified Based on the Survey Data)	Number of Plants
Coal	463
Gas	44
Gas - Combined Cycle	109
Nuclear	20
Oil	13
Petroleum Coke	9
Combination: Gas-CC and Nuclear and Oil	1
Combination: Gas-CC and Oil	3
Combination: Gas and Gas-CC	14
Combination: Gas and Gas-CC and Oil	1
Combination: Gas and Oil	3
Total	**680**

A.2.3 Survey Results for the Coal and Petroleum Coke Plants and the Subsample for Parts E, F, and G

The 504 coal and petroleum coke plants identified at the survey design stage were selected with certainty, but only a subsample of 97 of these plants was selected to receive Parts E, F, and G of the questionnaire using the sample design described in Section A.1.4.

Of the 94 coal plants that were selected to receive Parts E, F, and G, 92 plants remained eligible after receiving the survey responses. Of the 3 petroleum coke plants selected to receive Parts E, F, and G, two plants remained eligible after receiving the survey responses.

Further, the updated pond-landfill status for each plant was obtained from Part A, which was completed by every regular sample plant, including those that were not subject to subsampling. Based on the survey information, EPA found that some of the pond-landfill for coal and petroleum coke plants were incorrectly classified in the frame. The table below provides the final summary of how these coal and petroleum coke plants were classified based on the updated survey data.

Table A-5. Frequency Summary by the Updated Pond-Landfill Status for Eligible Coal Plants and by Petroleum Coke Status in the Population and in the Parts EFG Subsample

Updated Pond/Landfill Stratum (Based on the Survey Data)	Eligible Plants in the Population	Eligible Plants in Subsample
Coal - Both Pond and Landfill	192 [a]	56
Coal - Landfill Only – FGD	12	1
Coal - Landfill Only – No FGD	22	1
Coal - Pond Only – FGD	37	7
Coal - Pond Only – No FGD	112 [a]	27
Coal - No Pond or Landfill	88	0
Petroleum Coke	9	2
Total	**472**	**94**

a – The count includes coal plants, which were excluded from subsampling due to concerns of burden.

A.3 Weighting Of The Survey Data

This section describes the weighting procedure for the regular sample and the subsample at the plant level.

A.3.1 Plant-Level Weighting

Weighting the survey data starts with calculating the base weight, which is the inverse of the sampling probability, and then nonresponse adjustment is usually applied. Nonresponse adjustment entails adjusting the base weight for both non-response and unknown eligibility. However for the Steam Electric Survey, there was neither non-response nor sample plants with unknown eligibility. Thus, there was no need for EPA to apply this type of weighting adjustment. Consequently, the final weight for this survey is defined as the base weight for all sample plants in the regular sample (note that the Parts EFG subsample is also included in the regular sample). The ineligible plants in the sample represent the ineligible population and are given the same base weights as well.

Reclassification of stratification variables does not affect the weighting because the weight is the inverse of the selection probability, which is determined at the time of sample selection. However, a reclassified stratum now consists of plants from other design strata that may have different weights, and this would affect analyses that would be done using the updated classification. Table A-6 shows the original population and sample sizes, the number of sample plants that were eligible among the original regular sample, the final weight, the reclassified number of eligible plants that includes plants from other strata due to reclassification, and the estimated population size based on updated classification, which was calculated as the sum of final weights of the reclassified plants.

Table A-6. Estimated Eligible Population Size for Survey-Based Fuel Type Classification

Fuel Classification	Regulatory Status	Population Size in Frame	Original Sample Size	Number of Eligible Plants	Final Weight	Reclassified No. of Eligible Plants [a]	Estimated Population Size [b]
Coal	Regulated	344	344	328	1.0	323	**323**
	Unregulated	151	151	141	1.0	140	**140**
Gas	Regulated	129	39	29	3.308	31	**98**
	Unregulated	54	16	9	3.375	13	**39**
Gas-CC	Regulated	96	29	28	3.310	30	**92**
	Unregulated	276	83	78	3.325	79	**258**
Nuclear	Regulated	31	10	10	3.1	10	**31**
	Unregulated	32	10	10	3.2	10	**32**
Oil	Regulated	23	10	9	2.3	8	**18**
	Unregulated	20	10	9	2.0	5	**10**
Petroleum Coke [a]	Regulated	0	0	0	-	1	**1**
	Unregulated	9	9	8	1.0	8	**8**
Comb: Gas-CC, Nuclear & Oil	Regulated	1	1	1	1.0	1	**1**
	Unregulated	0	0	0	-	-	**-**
Comb: Gas-CC and Oil	Regulated	2	2	2	1.0	2	**2**
	Unregulated	0	0	0	-	1	**1**
Comb: Gas and Gas-CC	Regulated	20	10	10	2.0	12	**26**
	Unregulated	6	6	5	1.0	2	**2**
Comb: Gas and Gas-CC and Oil	Regulated	1	1	1	1.0	1	**1**
	Unregulated	0	0	0	-	0	**-**
Comb: Gas and Oil	Regulated	1	1	1	1.0	0	**-**
	Unregulated	1	1	1	1.0	3	**5**
Total		**1,197**	**733**	**680**	**-**	**680**	**1,088**

a – The count includes reclassified plants initially belonging to a different design stratum.

b – This column shows the sum of the final weights of reclassified plants that was rounded to the nearest integer.

While the column "Number of Eligible Plants" provides the number of eligible plants based on the original fuel type classification (regardless of their reclassified fuel type), the column named "Reclassified Number of Eligible Plants" gives the number of eligible plants based on the reclassification of their fuel type. For example, there were 29 eligible plants among those plants originally classified as gas – regulated but 31 plants fell in the class after reclassification based on the survey response. Therefore, it should be noted that the estimated population size in the last column is the (rounded) sum of the final weights of the reclassified eligible plants as each plant carries its own final weight wherever it is reclassified. It is not the same in general as the product of the reclassified number of eligible plants (which may have different final weights due to reclassification) and the final weight for the original stratum.[181]

In general, the estimated population size is smaller than the frame population size for due to reclassification and loss of ineligible plants. However, it could be larger if more plants were reclassified into that stratum. The overall estimated population size for this survey is 9.9 percent less than the frame population size due to loss of ineligible plants.

The same weighting principle applies to the subsample of 97 coal or petroleum coke plants that received Parts E, F, and G because this subsample was selected from the census of the coal/petroleum coke population. However, there is an important departure from the weighting method used for the full (regular) sample because the subsample was made also to cover plants, which were not subject to subsampling. Moreover, it was necessary to do more because almost half of the plants in the subsample changed their stratification. So, post-stratification weight adjustment was used to address these issues, which is further explained in Section A.3.2 below.

A.3.2 Plant-Level Weighting for the Parts EFG Subsample

The subsample of 97 plants was selected from the 504 coal or petroleum coke plants identified in the sample frame to receive Parts E, F, and G of the questionnaire. However, 206 plants were not subject to subsampling (including plants operated by small entities (61), plants with no CCR pond or landfill (143), and plants excluded to avoid overburdening (2)). Nevertheless, EPA wanted to use the subsample to represent the whole population. Therefore, non-coverage weighting adjustment was performed for the subsample.

One subsample was selected for Parts E, F, and G but Part E items do not have as much bearing with the Pond-Landfill status as do Parts F and G items. Part E of the questionnaire collected information about metal cleaning wastes, which is relevant to all plants, including plants with or without CCR ponds or landfills. On the other hand, since Parts F and G are applicable only to coal or petroleum coke plants with CCR ponds or landfills, the weighting had to account for the Pond-Landfill status. To address the difference in the characteristics of Part E items and Parts F and G items, two different sets of weights were developed as explained below: one set for Part E and another set for Parts F and G.

A.3.2.1 Development of the Final Weight for Part E

As explained in the previous section, the relevant Part E items do not have much bearing with the stratification by the Pond-Landfill status. Therefore, non-coverage weight adjustment was done so that the sum of the adjusted weights of the subsample of 94 eligible plants is equal to the eligible population size of 472 (504 frame size minus 32 plants that were ineligible or were reclassified as non-coal or non-petroleum coke plants) regardless of their Pond-Landfill status. This amounts to using a single weighting adjustment factor that is given by 472 divided by the total sum of the base weights of 94 eligible subsample plants, which is 290.4, so the factor is

[181] In the Gas – Regulated stratum, there are 31 reclassified eligible plants, which consist of 29 original plants and 2 reclassified from the Coal stratum (see Table A-6). Therefore, the estimated eligible population size for the Gas – Regulated stratum is obtained by 29*3.308+2*1 = 97.932, which is rounded to 98.

472/290.4 = 1.6253. This factor is multiplied by the subsampling base weights to obtain the Part E final weights.

A.3.2.2 Development of the Final Weight for Parts F and G

Since Parts F and G are only applicable to coal or petroleum coke plants with a CCR pond or landfill, the relevant population for Parts F and G consists of all eligible coal plants with either a CCR pond or a CCR landfill or petroleum coke plants. Therefore, the subsample of 94 coal or petroleum coke plants was weighted so that the final weights sum to the eligible population size of 384 coal plants with a pond or landfill and petroleum coke plants (*i.e.*, 384 = 472 eligible coal and petroleum coke plants – 88 plants without pond/landfill).

As shown in Table A-5 above, after the reclassification process, it was found that the numbers of sampled plants in some updated substrata are very small (*i.e.*, in the updated "Coal – Landfill Only – FGD" and "Coal – Landfill Only – No FGD" strata, there was only 1 plant in each received Parts E, F, and G of the questionnaire). Moreover, the ratios between the population sizes and sample sizes vary widely. This indicates that if updated substrata are used as post-strata for weight adjustment, the resulting weights will be very unstable, and it will cause instability of the variance estimate. Therefore, small substrata were collapsed to form the post-strata. With this goal in mind, the updated substrata "Coal – Landfill Only – FGD" and "Coal – Landfill Only – No FGD" were collapsed into the updated substratum "Coal – Both Pond and Landfill" resulting in four post-strata as follows:

- Post-stratum 1: Coal – Both Pond and Landfill, Coal – Landfill Only – FGD, and Coal – Landfill Only – No FGD;
- Post-stratum 2: Coal - Pond Only – FGD;
- Post-stratum 3: Coal - Pond Only – No FGD;
- Post-stratum 4: Petroleum Coke.

Note that all post-strata above were defined using the updated strata.

The weight adjustment factors presented below were used to obtain the final survey weights, which are the product of the adjustment factor and the initial base weight in each post-stratum. The weight adjustment factor is defined as the ratio of the population size to the sum of base weights of eligible subsample plants in the post-stratum.

Table A-7. Weight Adjustment Factors for the Four Post-Strata

Post Stratum Number	Updated Substratum	Population Size	Eligible Sample Size	Weight Adjustment Factor
1	Coal - Both Pond and Landfill Coal - Landfill Only – FGD Coal - Landfill Only - No FGD	226	58	1.27
2	Coal - Pond Only – FGD	37	7	1.86
3	Coal - Pond Only - No FGD	112	27	1.24
4	Pet-Coke - Selected for EFG	9	2	4.5
Total		**384**	**94**	

A.4 Estimation Method

This section presents the general methodology and equations for calculating estimates from the survey.

A.4.1 National Estimates

The survey collected many sub-items below the plant level. For example, some characteristics of generating units were collected. However, sub-units (*e.g.*, generating unit) below the plant were all selected, therefore the weight appropriate for weighted analysis is the same as the plant level weight. Some of the missing data were filled in using data from the 2009 EIA database, which is the same year basis as the data provided in response to the questionnaire. A small amount of missing data remains, primarily among the sub-plant level variables. Nevertheless, in the discussion below, no adjustments are made for missing data. For most variables, the consequence of this is negligible due to the small amount of missing data.

There are three levels of analytical unit (plant, generating unit, sub-generating-unit element) with item characteristics at each of these levels. Let w_{hi} be the sampling weight for plant i within variance stratum h.[182] The variance stratum is defined in the following section, where variance estimation is explained.

Different formulas are used for point estimation depending on the type of estimate. Since estimation of the population total is the most basic, and many estimates can be defined using the total estimates, we first discuss estimation of the population total.

Suppose that the parameter of interest is the population total (Y) of a variable denoted by y. Then the plant-level weighted total of the y-values for plant i in variance stratum h, $\hat{y}_{hi}$, is defined as:

[182] We could use the design stratum to give the estimation formula but to tie point estimation with variance estimation, it is more convenient to use the variance stratum.

$$\hat{y}_{hi} = \begin{cases} w_{hi} y_{hi} & \text{if the } y\text{-variable is at the plant level} \\ w_{hi} \sum_j y_{hij} & \text{if the } y\text{-variable is at the generating-unit level} \\ w_{hi} \sum_j \sum_k y_{hijk} & \text{if the } y\text{-variable is at the sub-generating-unit level} \end{cases} \quad (1)$$

Using this, the total Y is estimated by:

$$\hat{Y} = \sum_{h=1}^{H} \sum_{i=1}^{n_h} \hat{y}_{hi} \quad (2)$$

where H is the total number of variance strata, and n_h is the number of sample plants in variance stratum h for the analysis. Note that the strata involved in analysis depend on the analysis variables (items). If the variable is one of the Part E, F, or G items, then the strata are those for the Parts EFG subsample. The "hat" over the population parameter indicates an estimate of the parameter. When a weighted frequency (*e.g.*, the total number of generating units with a fly wet handling system) is calculated, the same formula is used, but the analysis variable y has a value of one if the case has the attribute (*e.g.*, having a fly wet handling system), and a value of zero otherwise.

To estimate the population mean, we need an estimate of the eligible population size (N), and it is estimated by the sum of the weights as follows:

$$\hat{N} = \sum_{h=1}^{H} \sum_{i=1}^{n_h} \hat{N}_{hi} = \sum_{h=1}^{H} \sum_{i=1}^{n_h} w_{hi} c_{hi} \,. \quad (3)$$

where c_{hi} is the count of the analysis units for plant i in variance stratum h – it is one if the analysis unit is the plant, otherwise the count of sub-plant level units.

An estimate of the population mean ($\overline{Y}$) for y-variable is given by:

$$\hat{\overline{Y}} = \frac{\hat{Y}}{\hat{N}} \,. \quad (4)$$

Population proportions are estimated by (4) if the y-variable is dichotomous. The estimate given by (4) is defined as the ratio of two total estimates, so it is called the ratio estimate. When the population parameter of interest is a ratio (R) of two analysis variables y and x, then it is defined as the ratio of two estimated totals:

$$\hat{R} = \frac{\hat{Y}}{\hat{X}} \quad (5)$$

A.4.2 Variance Estimation

The original regular sample was selected by a stratified equal probability sample of plants, and some strata are very small in size. For variance estimation, small design strata with one or two plants selected in Combination strata were collapsed into one stratum. This redefined stratum and other original design strata were used as strata for variance estimation, and for this reason, they are called variance strata.

For the Parts EFG subsample, a stratified equal probability sampling method was also used except for those coal plants with a leachate collection system, which were selected with certainty. These original substrata were also the variance strata for variance estimation for the variables from Parts E, F, and G.

Any elements below the plant level such as the generating unit were selected with certainty. Therefore, the sample design can be regarded as a single stage cluster sample for items at the sub-plant level, where the plants are the primary sampling unit (PSU) and sub-plant level elements are the secondary sample unit (SSU). Furthermore, the sub-generating-unit element under the generating unit can be considered as the tertiary sampling unit (TSU). The PSUs are usually used as variance units for variance estimation, where the variance of an estimate (*e.g.*, total) is calculated as the variability of PSU estimates, as is the case for the Steam Electric Survey. The variance estimate for the total estimate given in (2) is given by:

$$\hat{V}(\hat{Y}) = \sum_{h=1}^{H} \left(1 - f_h\right) \quad {}_{i=1}^{n_h} \left(\hat{y}_{hi} - \bar{\hat{y}}_h\right)^2 \Big/ \left(n_h - 1\right) \tag{6}$$

where $f_h = n_h / N_h$, which is the variance stratum sampling fraction, n_h is the plant sample size of the variance stratum for the analysis, N_h is the variance stratum population size, and $\bar{\hat{y}}_h = \sum_{i=1}^{n_h} \hat{y}_{hi} / n_h$. The factor $1 - f_h$ in (6) is called the finite population correction (FPC). The variance estimate for a non-linear statistic such as the ratio estimate given by equation (4) or (5) needs a different formula or technique.

There are two main approaches for estimating the variance of a non-linear point estimate: the Taylor linearization method and resampling methods. For the analyses in all parts (except for Parts F and G), the Taylor method was used. Since complex post-stratification weighting was used for Parts F and G items, a resampling method known as the jackknife was chosen for the analysis, for which the jackknife replicate weights were developed for the Parts F and G. For analysis of Parts F and G variables the Taylor method could have been used as well, but the jackknife variance estimates were used since they are less biased. The jackknife and FPC factors for analysis of variables from Parts F and G are provided in the following table.

Table A-8. The Jackknife and Finite Population Correction (FPC) Factors for Parts F and G

Variance Stratum	Description of Variance Stratum	Number of Replicates	Jackknife Factor	FPC Factor
1	Coal – Both Pond and Landfill	23	0.95652	0.77841
2	Coal – Landfill Only – FGD	9	0.88889	0.59805
3	Coal – Landfill Only – No FGD	14	0.92857	0.78810
4	Coal – Pond Only - FGD	11	0.90909	0.78898
5	Coal – Pond Only – No FGD	28	0.96429	0.76230
6	Coal – All other types	7	0.85714	0.24871
7	Petroleum coke – Selected for EFG	2	0.5	0.77778

Appendix B

MODIFIED DELTA-LOG NORMAL DISTRIBUTION

Appendix B: Modified Delta-Lognormal Distribution

Appendix B describes the modified delta-lognormal distribution and the estimation of the plant-specific long-term averages and plant-specific variability factors used to calculate the limitations and standards. This appendix provides the statistical methodology that was used to obtain the results presented in Section 13 of the Technical Development Document. For simplicity, in the remainder of this appendix, references to "limitations" include "standards."

The term "detected" in this document refers to analytical results measured and reported above the sample-specific quantitation limit. Thus, the term "non-detected" refers to values that are below the method detection limit (MDL) and those measured by the laboratory as being between the MDL and the quantitation limit (QL).

Effluent concentrations are often autocorrelated such that concentrations in samples collected close together in time are more similar than concentrations from samples collected farther apart in time. When the data are deemed to be positively autocorrelated, the variance estimate from samples collected on successive days will be less than the variance of the long-term concentration series, and thus the variance estimates from the sampled days should be adjusted for the correlation when estimating the variance for the long-term series. Equations (17) and (34) below include autocorrelation adjustments to the basic equations for calculating the limits using the modified-delta-lognormal distribution.[183] See Section 13 of the Technical Development Document for a discussion of using autocorrelation in calculating the limits.

B.1 <u>Basic Overview of the Modified Delta-Lognormal Distribution</u>

EPA selected the modified delta-lognormal distribution to model pollutant effluent concentrations from the steam electric power generating industry in developing the long-term averages (LTA) and variability factors. A typical effluent data set from EPA sampling, Clean Water Act (CWA) 308 sampling, or from a plant's self-monitoring consists of a mixture of measured (detected) and non-detected values. The modified delta-lognormal distribution is appropriate for such datasets because it models the data as a mixture of detected measurements that follow a lognormal distribution and non-detect measurements that occur with a certain probability. The model also allows for the possibility that non-detected measurements occur at multiple sample-specific detection limits. Because the data appeared to fit the modified delta-lognormal model reasonably well, EPA has determined that this model is appropriate for these data.

The modified delta-lognormal distribution is a modification of the 'delta distribution' originally developed by Aitchison and Brown (1963). While this distribution was originally developed to model economic data, other researchers have shown the application to environmental data [Owen and DeRouen, 1980]. The resulting mixed distributional model, which combines a continuous density portion with a discrete-valued spike at zero, is also known as the delta-lognormal distribution. The delta in the name refers to the proportion of the overall

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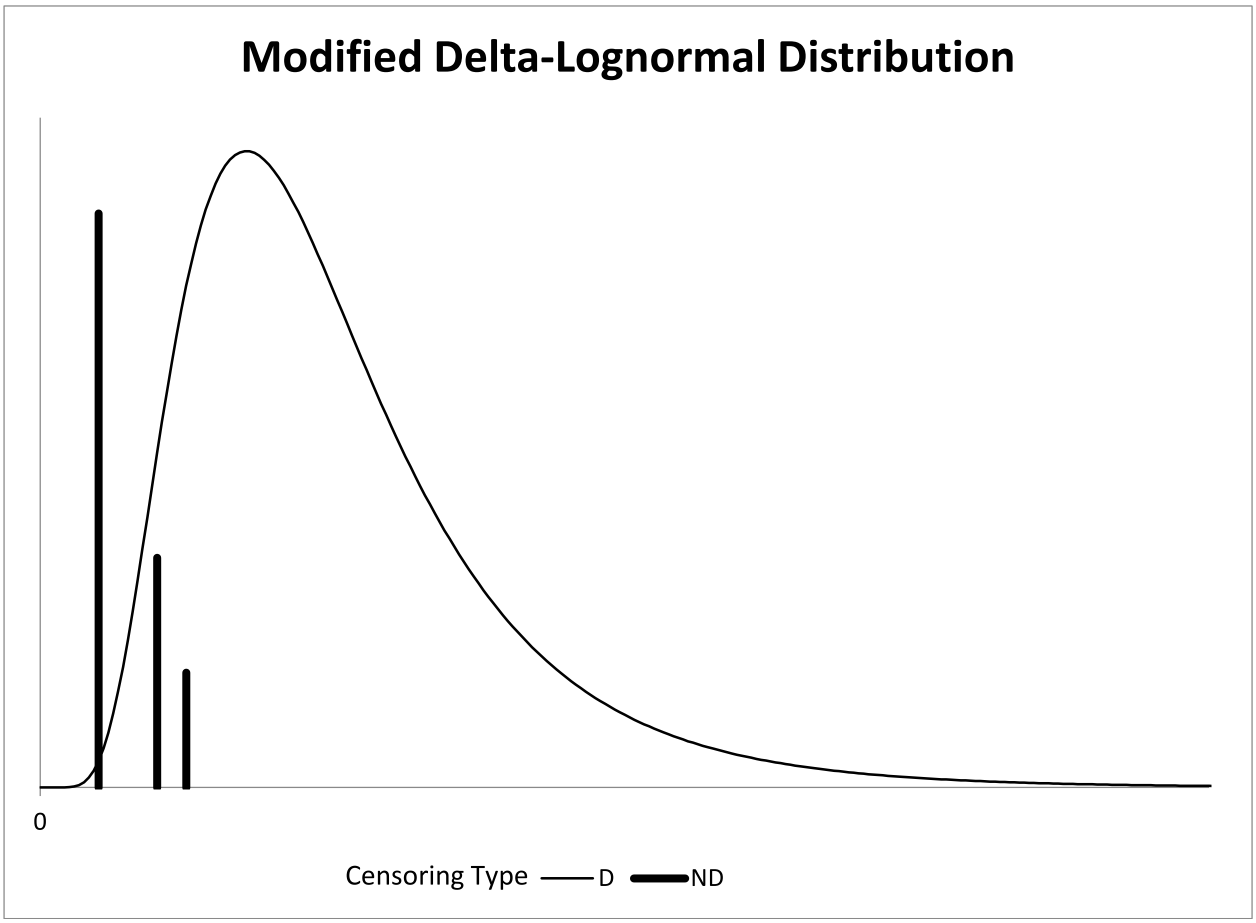
[183] In response to comments on the proposed rule, EPA reviewed the procedures used to adjust for correlation for the proposed rule and used in previous effluent guidelines. The equations for this final rule were previously used for the Iron and Steel effluent guidelines except those guidelines used equation (19) instead of equation (18). Since the samples for this rule were not collected on sequential days, equation (18) is used.

distribution contained in the discrete distributional spike at zero (i.e., the proportion of zero amounts). The remaining non-zero amounts are grouped together and fit to a lognormal distribution.

EPA modified this delta-lognormal distribution to incorporate multiple detection limits. In the modification of the delta portion, the single spike located at zero is replaced by a discrete distribution made up of multiple spikes. Each spike in this modification is associated with a distinct sample-specific detection limit associated with non-detected (ND) measurements in the database. A lognormal density is used to represent the set of detected (D) values. This modification of the delta-lognormal distribution is illustrated in the figure below.



The following two sections describe the delta and lognormal portions of the modified delta-lognormal distribution in further detail.

B.2 Continuous and Discrete Portions of the Modified Delta-Lognormal Distribution

In the discrete portion of the modified delta-lognormal distribution, the non-detected values correspond to the *k* reported sample-specific detection limits. In the model, δ represents the proportion of non-detected values and is the sum of δ_i, i=1,…,k, which represents the proportion of non-detected values associated with the i^{th} distinct detection limit. By letting D_i

equal the value of the i^{th} smallest distinct detection limit in the dataset and letting the random variable X_D represent a randomly chosen non-detected measurement, the cumulative distribution function of the discrete portion of the modified delta-lognormal model can be mathematically expressed as:

$$Pr(X_D \leq c) = \frac{1}{\delta} \sum_{i:D_i \leq c} \delta_i \text{ , } c > 0 \quad (1)$$

The mean and variance of this discrete distribution can be calculated using the following formulas:

$$E(X_D) = \frac{1}{\delta} \sum_{i=1}^{k} \delta_i D_i \quad (2)$$

$$Var(X_D) = \frac{1}{\delta} \sum_{i=1}^{k} \delta_i (D_i - E(X_D))^2 \quad (3)$$

EPA used the continuous, lognormal portion of the modified delta-lognormal distribution to model the detected measurements. The cumulative probability distribution of the continuous portion of the modified delta-lognormal distribution can be mathematically expressed as:

$$Pr(X_C \leq c) = \Phi\left(\frac{ln(c) - \mu}{\sigma}\right) \quad (4)$$

where:

X_C	=	A randomly chosen detected measurement.
$\Phi(\cdot)$	=	The cumulative distribution function of the standard normal distribution.
μ and σ	=	Parameters of the log-normal distribution (the mean and standard deviation of the log-transformed concentrations).

The expected value, $E(X_C)$, and the variance, $Var(X_C)$, of the lognormal distribution can be calculated as:

$$E(X_c) = exp\left(\mu + \frac{\sigma^2}{2}\right) \quad (5)$$

$$Var(X_C) = \left(E(X_C)\right)^2 (exp(\sigma^2) - 1) \quad (6)$$

B.3 Combining the Continuous and Discrete Portions

The continuous portion of the modified delta-lognormal distribution is combined with the discrete portion to model data that contain a mixture of non-detected and detected measurements. It is possible to fit a wide variety of observed effluent data to the modified delta-lognormal distribution. Multiple detection limits for non-detect measurements are incorporated, as are measured ("detected") values. The same basic framework can be used even if there are no non-detected values in the dataset (in this case, it is the same as the lognormal distribution). Thus, the modified delta-lognormal distribution offers a large degree of flexibility in modeling effluent data.

The modified delta-lognormal random variable *U* can be expressed as a combination of three other independent variables as follows:

$$U = I_U X_D + (1 - I_U) X_c \tag{7}$$

where:

X_D	=	A random non-detect from the discrete portion of the distribution.
X_C	=	A random detected measurement from the continuous lognormal portion.
I_U	=	A variable indicating whether any particular random measurement, *U*, is non-detected or detected (i.e., I_U=1 if *u* is non-detected, and I_U=0 if *u* is detected).

Using a weighted sum, the cumulative distribution function from the discrete portion of the distribution (equation 1) can be combined with the function from the continuous portion (equation 4) to obtain the overall cumulative probability distribution of the modified delta-lognormal distribution:

$$Pr(U \leq c) = \left(\sum_{i:D_i \leq c} \delta_i \right) + (1 - \delta)\Phi\left(\frac{ln(c) - \mu}{\sigma} \right) \tag{8}$$

The expected value of the random variable *U* can be derived as a weighted sum of the expected values of the discrete and continuous portions of the distribution (equations 2 and 5, respectively) as follows:

$$E(U) = \delta E(X_D) + (1 - \delta) E(X_C) \tag{9}$$

In a similar manner, the expected value of U^2 can be written as a weighted sum of the expected values of the squares of the discrete and continuous portions of the distribution:

$$E(U^2) = \delta E(X_D^2) + (1 - \delta) E(X_C^2) \tag{10}$$

Although written in terms of U, the following relationship holds for all random variables:

$$E(U^2) = Var(U) + \left(E(U)\right)^2 \tag{11}$$

Now using equation (11) to solve for Var(U), and applying the relationships in equations (9) and (10), the variance of U is given by:

$$Var(U) = \delta\left(Var(X_D) + \left(E(X_D)\right)^2\right) + (1-\delta)\left(Var(X_C) + \left(E(X_C)\right)^2\right) - \left(E(U)\right)^2 \tag{12}$$

Thus the modified delta-lognormal distribution can be described by the following parameters: the k distinct detection limits, Di, and their corresponding probabilities, $\delta_i, i = 1, \ldots, k$ and the parameters μ and σ of the lognormal distribution for detected values in the continuous portion of the distribution.

B.4 Autocorrelation

The correlation among daily measurements can be described by the sequence of correlations between observations that are 1 day apart, 2 days apart, 3 days apart, etc. There are many time series models that might be considered for modeling this sequence of correlations and the associated wastewater measurements. One such model is an AR(1) model, an autoregressive model with one parameter, ρ, the correlation between observations one day apart. If the data are consistent with an AR(1) model, the correlation between observations d days apart will be ρ^d. The AR(1) model is a reasonable model for many series of wastewater measurements when applied to the log-transformed concentrations. Based on analysis of the effluent data for this rule, EPA has used the AR(1) model for describing the correlations among the steam electric effluent measurements.

Use of the AR(1) model requires estimating ρ. When the data come from sequential daily samples with no values below the detection limit, ρ can be estimated by the correlation between log-transformed measurements separated by one day. When the data are not from sequential samples, standard statistical software for time series analysis can be used to estimate ρ. When the data also have non-detects, as in the data used to develop this rule, estimates based on standard statistical software can be biased. DCN SE06279 describes the procedures used to estimate the 1-day lag correlation for the effluent data adjusting for the effect of any non-detects.

EPA estimated the 1-day lag correlation for each analyte within each plant for which there were enough data to provide a reasonably precise correlation estimate. When there were two or more plants with correlation estimates for a combination of analyte and treatment option, EPA averaged the correlations to obtain the correlation used for calculating the limitations. Unless specified otherwise, for combinations of analyte and technology option with no correlation estimate, EPA assumed the correlation was zero.

In the equations below, EPA used the correlation to calculate the variance of the long-term concentration series from the variance of the observed measurements. The correlation is also used when calculating the variance of the monthly mean from the variance of the long-term series. As implemented in the equations below, the correlation adjustment affects only the variance of the continuous portion of the modified delta lognormal distribution, and the non-detects are assumed to be statistically independent.

B.5 Plant and Pollutant Dataset Requirements

The parameter estimates for the lognormal portion of the modified delta-lognormal distribution can be calculated with as few as two distinct detected values in a dataset. (In order to estimate the variance of the modified delta-lognormal distribution, at least two distinct detected values are required.)

For this rulemaking, EPA used a plant dataset for a pollutant to calculate the plant-specific LTA and variability factor if the dataset contained three or more observations with at least two distinct detected concentration values. If the plant dataset for a pollutant did not meet these requirements, EPA used an arithmetic average to calculate the plant-specific LTA and excluded the dataset from the variability factor calculations (since the variability could not be calculated in this situation).

B.6 Parameter Estimates for Modified Delta-Lognormal Distribution of Daily Concentrations

To use the modified delta-lognormal model, the parameters of the distribution must be estimated from the data. These estimates are then used to calculate the limitations. The following assumes that the parameter estimates are calculated from *n* observed daily values.

The parameters δ_i and δ are estimated from the data using the following formulas:

$$\hat{\delta}_i = \frac{1}{n}\sum_{j=1}^{n_d} I\left(d_j = D_i\right) \tag{13a}$$

$$\hat{\delta} = \frac{n_d}{n} \tag{13b}$$

where n is the number of measurements (both detected and non-detected), $I(\cdot)$ is an indicator function equal to one if the argument is true (and zero otherwise), d_j, $j = 1,\ldots, n_d$, is the detection limit for the j^{th} non-detected measurement, and n_d is the total number of non-detected measurements. The "hat" over the parameters indicates that these values are estimated from the data.

The expected value and the variance of the discrete portion of the modified delta-lognormal distribution can be estimated from the data as:

$$\hat{E}(X_D) = \frac{1}{\hat{\delta}}\sum_{i=1}^{k} \hat{\delta}_i\, D_i \tag{14}$$

$$\hat{V}ar(X_D) = \frac{1}{\hat{\delta}}\sum_{i=1}^{k} \hat{\delta}_i \left(D_i - \hat{E}(X_D)\right)^2 \tag{15}$$

The parameters μ and σ of the continuous portion of the modified delta-lognormal distribution are estimated from the log-transformed data using:

$$\hat{\mu} = \sum_{i=1}^{n_c} \frac{ln(x_i)}{n_c} \tag{16}$$

$$\hat{\sigma}^2 = \frac{1}{g(\rho_c)} \sum_{i=1}^{n_c} \frac{(ln(x_i) - \hat{\mu})^2}{n_c - 1} \tag{17}$$

where:

x_i	=	The i^{th} detected measurement.
n_c	=	The number of detected measurements (note that $n = n_d + n_c$), and $g(\rho_c)$ is the adjustment for autocorrelation based on the 1-day lag correlation of the values in the continuous portion of the modified delta lognormal distribution (ρ_c).The flow rate of the wastestream being discharged, in gallons per day.

For an AR(1) model with a 1-day lag correlation of ρ_c, the correlation (in the log scale) between xi and xj (i ≠ j) is Corr(ln(xi), ln(xj)) =$\rho_c^{|i-j|}$, where i and j are the sample collection dates. Using this, the adjustment for the autocorrelation is:

$$g(\rho_c) = 1 - \frac{1}{n_c(n_c - 1)} \sum_{i \in T} \sum_{j \in T, j \neq i} \rho_c^{|i-j|} \tag{18}$$

where T = {1,...,n} is the set of dates with observed daily values above the detection limit (i.e., in the continuous portion of the distribution). For an AR(1) model with n sequential daily values, this reduces to:

$$g(\rho_c) = 1 - \left(\frac{2}{n_c(n_c - 1)}\right)\left(\frac{\rho_c}{1 - \rho_c}\right)\left((n_c - 1) - \frac{\rho_c\left(1 - {\rho_c}^{n-1}\right)}{1 - \rho_c}\right) \tag{19}$$

Note that if the daily values are independent (i.e., autocorrelation is not present in the data), then $g(\rho_c) = 1$.

The expected value and the variance of the lognormal portion of the modified delta-lognormal distribution can be calculated from the parameter estimates as:

$$\hat{E}(X_C) = exp\left(\hat{\mu} + \frac{\hat{\sigma}^2}{2}\right) \tag{20}$$

$$\hat{V}ar(X_C) = \left(\hat{E}(X_C)\right)^2 (exp(\hat{\sigma}^2) - 1) \tag{21}$$

Finally, the expected value and variance of the modified delta-lognormal distribution can be estimated using the following formulas:

$$\hat{E}(U) = \hat{\delta}\hat{E}(X_D) + \left(1 - \hat{\delta}\right)\hat{E}(X_C) \tag{22}$$

$$\hat{V}ar(U) = \hat{\delta}\left(\hat{V}ar(X_D) + \left(\hat{E}(X_D)\right)^2\right) + \left(1 - \hat{\delta}\right)\left(\hat{V}ar(X_C) + \left(\hat{E}(X_C)\right)^2\right) - \left(\hat{E}(U)\right)^2 \tag{23}$$

Equations (20) through (23) are particularly important in the estimation of the plant LTAs and variability factors as described in the following sections.

B.6.1 Estimation of Plant-Specific LTA

The plant-specific LTA is calculated as follows:

$$LTA = \hat{E}(U) = \hat{\delta}\hat{E}(X_D) + \left(1 - \hat{\delta}\right)\hat{E}(X_C) \tag{24}$$

Section B.6 contains all the formulas used for each of the expressions above. In the case where there are less than two distinct detected values, the variance in equation (17) cannot be calculated. In this case, the LTA is calculated as the arithmetic mean of the available data (consisting of detected values and detection limits).

B.6.2 Estimation of the Plant-Specific Daily Variability Factor (VF1)

The plant-specific daily variability factor is the ratio of the 99th percentile of the daily concentrations to the LTA and is calculated as follows:

$$VF1 = \frac{\hat{P}_{99}}{\hat{E}(U)} = \frac{\hat{P}_{99}}{LTA} \tag{25}$$

The following describes how the 99th percentile of the modified delta-lognormal distribution is estimated, including how multiple detection limits are accounted for when estimating the 99th percentile.

The cumulative distribution function, p, for a given value c is:

$$Pr(U \leq c) = \left(\sum_{i:D_i \leq c} \hat{\delta}_i\right) + \left(1 - \hat{\delta}\right)\Phi\left(\frac{ln(c) - \hat{\mu}}{\hat{\sigma}}\right) \tag{26}$$

Under the modified delta-lognormal distribution, if $D_1 < D_2 < \ldots < D_k$ are the k observed detection limits expressed in increasing order, then the cumulative distribution at each detection limit is:

$$\hat{q}_m = \left(\sum_{i=1}^{m} \hat{\delta}_i\right) + (1 - \hat{\delta})\Phi\left(\frac{ln(D_m) - \hat{\mu}}{\hat{\sigma}}\right), \qquad m = 1 \ldots k \tag{27}$$

If all k of the $\hat{q}_m$ values are below 0.99, then

$$\hat{P}_{99} = exp\left(\hat{\mu} + \hat{\sigma} \cdot \Phi^{-1}\left(\frac{0.99 - \hat{\delta}}{1 - \hat{\delta}}\right)\right) \tag{28}$$

where $\Phi^{-1}(p)$ is the p^{th} percentile of the standard normal distribution. Otherwise, find j such that D_j is the smallest detection limit for which $\hat{q}_j \geq 0.99$, and let $\hat{q}^* = \hat{q}_j - \hat{\delta}_j$. Then the 99^{th} percentile is:

$$\hat{P}_{99} = \begin{cases} D_j & if\ \hat{q}^* < 0.99 \\ exp\left(\hat{\mu} + \hat{\sigma} \cdot \Phi^{-1}\left(\frac{0.99 - \sum_{i=1}^{j-1} \hat{\delta}_i}{1 - \hat{\delta}}\right)\right) & if\ \hat{q}^* \geq 0.99 \end{cases} \tag{29}$$

B.7 Parameter Estimates for Modified Delta-Lognormal Distribution of Monthly Averages

To calculate the 4-day variability factor (VF4), EPA assumed that the approximating distribution of $\overline{U}_4$, the sample mean for a random sample of four independent concentrations, was also derived from the modified delta-lognormal distribution in which the discrete portion corresponds to averages of four non-detects (assumed to be independent) and the continuous portion approximates the distribution of averages involving detected values (which may be correlated). The probability that the average involves four non-detects is:

$$\hat{\delta}_4 = \hat{\delta}^4 \tag{30}$$

To obtain the expected value of the mean of the four daily values, equation (22) is modified to indicate that it applies to the average:

$$\hat{E}(\overline{U}_4) = \hat{\delta}_4\left(\hat{E}(\overline{X}_4)_D\right) + (1 - \hat{\delta}_4)\hat{E}(\overline{X}_4)_C \tag{31}$$

where:

$(\overline{X}_4)_D$	=	The mean of the discrete portion of the distribution of the average of four independent concentrations (i.e., when all observations are non-detected).

$(\bar{X}_4)_C$ = The mean of the continuous lognormal portion (i.e., for averages involving one or more detected observations). The flow rate of the wastestream being discharged, in gallons per day.

First, EPA assumed that the detection of each measurement is independent. Therefore, the probability of the detection of the measurements can be written as $\hat{\delta}_4 = \hat{\delta}^4$. Because the measurements are assumed to be independent, the following relationships hold:

$$\hat{E}((\bar{X}_4)_D) = \hat{E}(X_D) \qquad (32)$$
$$\hat{V}ar((\bar{X}_4)_D) = \frac{\hat{V}ar(X_D)}{4}$$

Since the expected value of the daily concentrations and the monthly means are equal:

$$\hat{E}(\bar{U}_4) = \hat{E}(U) \qquad (33)$$

The variance of the monthly average (represented by $\hat{V}ar(\bar{U}_4)$) with the correlation adjustment is:

$$\hat{V}ar(\bar{U}_4) = \frac{\hat{V}ar(U)}{4}\left(1 + f_4(\rho_c)\right) \qquad (34)$$

where the factor $f_4(\rho_c)$ is used to adjust for the correlation among the four values in the average. This adjustment factor is shown below. Note that the correlation adjustment $\left(1 + f_4(\rho_c)\right)$ is equal to 1.0 if the correlation is zero. Although the calculation of the adjustment factor assumes all four weekly concentrations are detected (by using the correlation among detected values), in practice the observations used to calculate the monthly average may include non-detects.

In general, for a monthly average of m samples:

$$f_m(\rho_c) = \frac{1}{m}\sum_{i \in S}\sum_{j \in S, i \neq j} \frac{exp\left(\rho_c^{|i-j|}\hat{\sigma}^2\right) - 1}{exp(\hat{\sigma}^2) - 1} \qquad (35)$$

Where S represents the set of sampling dates within the month.

When four samples are collected 7 days apart, the correlation between detected values 7 days apart is ρ_c^7 and equation (35) is equal to:

$$f_4(\rho_c) = \frac{2}{4}\sum_{k=1}^{3}(4-k)\left(\frac{exp(\rho_c^{7k}\hat{\sigma}_A^2) - 1}{exp(\hat{\sigma}_A^2) - 1}\right) \qquad (36)$$

Substituting into equation (31) and solving for the expected value of the continuous portion of the distribution gives:

$$\hat{E}(\bar{X}_4)_C = \frac{\hat{E}(U) - \hat{\delta}_4 \hat{E}(X_D)}{1 - \hat{\delta}_4} \tag{37}$$

Using the relationship in equation (23) for the averages of four daily values, substituting terms from equations (32) to (34) and solving for the variance of the continuous portion of $\bar{U}_4$ gives:

$$\hat{V}ar((\bar{X}_4)_C) = \frac{\hat{V}ar(\bar{U}_4) + \left(\hat{E}(U)\right)^2 - \hat{\delta}_4\left(\hat{V}ar((\bar{X}_4)_D) + \left(\hat{E}(X_D)\right)^2\right)}{1 - \hat{\delta}_4} - \left(\hat{E}((\bar{X}_4)_C)\right)^2 \tag{38}$$

Using equations (20) and (21) and solving for the parameters of the lognormal distribution describing the distribution of $\left(\bar{X}_4\right)_C$ gives:

$$\begin{aligned} \hat{\sigma}_4^2 &= ln\left(\frac{\hat{V}ar((\bar{X}_4)_C)}{\left(\hat{E}((\bar{X}_4)_C)\right)^2} + 1\right) \\ \hat{\mu}_4 &= ln\left(\hat{E}((\bar{X}_4)_C)\right) - \frac{\hat{\sigma}_4^2}{2} \end{aligned} \tag{39}$$

The average of four non-detects can generate an average that is not necessarily equal to any of the $D_1, D_2,\ldots,D_k$. Consequently, more than k discrete points exist in the discrete portion of the distribution of the 4-day averages. For example, the average of four non-detects when there are k=2 distinct detection limits are at the following discrete k^* points with the associated probabilities denoted by δ_i^*, i=1,…, k^*:

i	**Value of $\bar{U}_4$ (D_i^*)**	**Probability of occurrence (δ_i^*)**
1	D_1	δ_1^4
2	$(3D_1 + D_2)/4$	$4\delta_1^3\delta_2$
3	$(2D_1 + 2D_2)/4$	$6\delta_1^2\delta_2^2$
4	$(D_1 + 3D_2)/4$	$4\delta_1\delta_2^3$
5 (=k^*)	D_2	δ_2^4

When all four observations are non-detected values, and when k distinct non-detected values exist, the multinomial distribution can be used to determine associated probabilities, as shown below:

$$Pr\left(\bar{U}_4 = \frac{\sum_{i=1}^{k} u_i D_i}{4}\right) = \frac{4!}{u_1!\,u_2!\cdots u_k!}\prod_{i=1}^{k}\delta_i^{u_i} \tag{40}$$

where u_i is the number of non-detected measurements at the detection limit D_i. The number k^* of possible discrete averages for k=1,…,5, are as follows:

K	*k**
1	1
2	5
3	15
4	35
5	70

B.7.1 Estimation of Plant-Specific Monthly Variability Factors (VF4)

Plant-specific monthly variability factors were based on 4-day monthly averages because EPA assumed the monitoring frequency to be weekly (approximately four times a month). The plant-specific monthly variability factor for each plant is the ratio of a 95th percentile to the LTA. In this case, the parameter to be estimated is the 95th percentile of the distribution of $\bar{U}_4$, which represents the average of four samples for a given plant. The monthly variability factor is calculated as follows:

$$VF4 = \frac{\hat{P}_{95}}{\hat{E}(U)} = \frac{\hat{P}_{95}}{LTA} \tag{41}$$

Below is a description of how the 95th percentile is estimated under the assumption that $\bar{U}_4$ has a modified delta-lognormal distribution. The following steps also show how EPA accounted for multiple detection limits (for non-detected values) when estimating the 95th percentile of the monthly average.

The approach to estimating P_{95} is similar to the approach used to estimate P_{99} in the calculation of daily variability factors, as described above. For m = 1, …, k*, let

$$\hat{q}_m = \left(\sum_{i=1}^{m}\hat{\delta}_i^*\right) + \left(1-\hat{\delta}^4\right)\Phi\left(\frac{ln(D_m^*) - \hat{\mu}_4}{\hat{\sigma}_4}\right) \tag{42}$$

where $\Phi(\cdot)$ is the cumulative distribution function of the standard normal distribution.

Now, if all *k* values of $\hat{q}_m$ defined above are less than 0.95, then the 95th percentile is defined as:

$$\hat{P}_{95} = exp\left(\hat{\mu}_4 + \hat{\sigma}_4 \cdot \Phi^{-1}\left(\frac{0.95 - \hat{\delta}^4}{1 - \hat{\delta}^4}\right)\right) \tag{43}$$

where $\Phi^{-1}(p)$ is the p^{th} percentile of the standard normal distribution. Otherwise, let D_j^* denote the smallest of the $k*$ values of D_i^* for which $\hat{q}_j \geq 0.95$, and let $\hat{q}* = \hat{q}_j - \hat{\delta}_j^*$. Then, the 95th percentile is defined by the following:

$$\hat{P}_{95} = \begin{cases} D_j^* & if\ \hat{q}^* < 0.95 \\ exp\left(\hat{\mu}_4 + \hat{\sigma}_4 \cdot \Phi^{-1}\left(\frac{0.95 - \sum_{i=1}^{j-1} \hat{\delta}_i^*}{1 - \hat{\delta}^4}\right)\right) & if\ \hat{q}^* \geq 0.95 \end{cases} \tag{44}$$

B.8 Evaluation of Plant-Specific Variability Factors

The parameter estimates for the lognormal portion of the distribution can be calculated with as few as two distinct measured values in a dataset (to calculate the variance); however, these estimates can be imprecise (as can estimates from larger datasets). As stated in Section B.5, EPA developed plant-specific variability factors for datasets that had three or more observations with two or more distinct measured concentration values.

To identify situations producing unexpected results, EPA reviewed all of the variability factors and compared daily to monthly variability factors. EPA used several criteria to determine if the plant-specific daily and monthly variability factors should be included in calculating the option variability factors (the option variability factors refer to the technology option variability factor for a pollutant rather than regulatory option). One criterion that EPA used was that the daily and monthly variability factors should be greater than 1.0. A variability factor less than 1.0 would result in an unexpected result where the estimated 99th percentile would be less than the LTA. This would be an indication that the estimate of σ (the standard deviation in log scale) was particularly large and most likely imprecise. A second criterion was that not all of the sample-specific detection limits could exceed the detected values. A third criterion was that the daily variability factor had to be greater than the monthly variability factor. All plant-specific variability factors used for the limitations and standards met these three criteria.

B.9 References

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