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

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ACE	Affordable Clean Energy
BA	bottom ash
BAT	Best Available Technology Economically Achievable
BMP	best management practices
BOD	biochemical oxygen demand
CAA	Clean Air Act
CBI	confidential business
CH_4	methane
CO_2	carbon dioxide
CPP	Clean Power Plan
CRL	combustion residual leachate
CSAPR	Cross-State Air Pollution Rule
CSC	compact submerged conveyor
CUR	capacity utilization rates
CWA	clean Water Act
CWT	centralized waste treatment
DOE	Department of Energy
EDR	electrodialysis reversal
EGU	electric generating unit
EIA	Energy Information Administration
EJA	environmental justice analysis
ELG	effluent limitations guidelines and standards
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
FBR	fluidized bed reactor
FGD	flue gas desulfurization
FGMC	flue gas mercury control
FO	forward osmosis

GHG	Greenhouse gas
GPM	gallons per minute
HAP	hazardous air pollutant
HRR	high recycle rate
HRT	hydraulic residence times
HRTR	high residence time reduction
HVAC	heating, ventilation, or air conditioning
ICR	information collection request
IPM	Integrated Planning Model
LRTR	low residence time reduction
LUEGU	low utilization electric generating units
MATS	Mercury and Air Toxics Standards
MDS	mechanical drag systems
MGD	million gallons per day
MGY	million gallons per year
MW	megawatts
N_2O	nitrous oxide
NAAQS	national ambient air quality standards
NOPP	notices of planned participation
NO_X	oxides of nitrogen
NPDES	National Pollutant Discharge Elimination System
NSPS	New Source Performance Standards
NWQEI	non-water-quality environmental impacts
OLEM	Office of Land and Emergency Management
PM	particulate matter
POTW	publicly owned treatment works
PSES	Pretreatment Standards for Existing Sources
QA	quality assurance
QC	quality control

RCRA	Resource Conservation and Recovery Act
RO	reverse osmosis
SCR	selective catalytic reduction
SO_2	sulfur dioxide
TCLP	toxicity characteristic leaching procedure
TDD	Technical Development Document
TDS	total dissolved solids
TMT	trimercapto-s-triazine
TPY	tons per year
TSS	total suspended solids
VIP	Voluntary Incentive Program
ZLD	zero liquid discharge
ZVI	Zero valent iron

1. Background

This Technical Development Document describes background information for the Agency's proposed supplemental rulemaking for the steam electric power generating point source category. This proposed rulemaking is based on a review of the effluent limitations guidelines and standards (ELGs) promulgated in 2020 (referred to as the 2020 rule) under Executive Order 13990.

EPA is proposing revisions to the 2020 rule based on a review of publicly available data and additional data collected from the steam electric power generating industry. The proposed revisions cover Best Available Technology Economically Achievable (BAT) and Pretreatment Standards for Existing Sources (PSES) requirements for flue gas desulfurization (FGD) wastewater, bottom ash (BA) transport water, combustion residual leachate (CRL), and legacy wastewater from steam electric power plants. This document presents information for the proposed revisions including details on EPA's data collection, industry profile updates (*e.g.,* retirements and treatment technology updates), methodologies for estimating costs, pollutant removals, and non-water-quality impacts.

In addition to this report, other supporting reports include:

- Supplemental Environmental Assessment for Proposed Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (EA), Document No. EPA-821-R-23-004. This report summarizes the potential environmental and human health impacts that are estimated to result from implementation of the proposed revisions to the 2015 and 2020 rules.
- Benefit and Cost Analysis for Proposed Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (BCA Report), Document No. EPA-821-R-23-003. This report summarizes estimated societal benefits and costs that are estimated to result from implementation of the proposed revisions to the 2015 and 2020 rules.
- Regulatory Impact Analysis for Proposed Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (RIA), Document No. EPA-821-R-23-002. This report presents a profile of the steam electric power generating industry, a summary of estimated costs and impacts associated with the proposed revisions to the 2015 and 2020 rules, and an assessment of the potential impacts on employment and small businesses.
- Environmental Justice Analysis for Proposed Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (EJA), Document No. EPA-821-R-23-001. This report presents a profile of the communities and populations potentially impacted by this proposal, analysis of the distribution of impacts in the baseline and proposed changes, and summary of input from potentially impacted communities that EPA met with prior to the proposal.

The ELGs for the steam electric power generating 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 use environmental data.

1.1 Legal Authority

EPA is revising the ELGs for the steam electric power generating point source category (40 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.

Congress passed the Federal Water Pollution Control Act Amendments of 1972, also known as the Clean Water Act (CWA), to "restore and maintain the chemical, physical, and biological integrity of the Nation's waters," per 33 U.S.C. 1251(a). 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 United States except as authorized under the CWA. Under section 402 of the CWA, discharges may be authorized through a National Pollutant Discharge Elimination System (NPDES) permit. The CWA also authorizes EPA to establish national technology-based ELGs for discharges from categories of point sources. Refer to the CWA for more information on these limitations, which could affect direct dischargers and indirect dischargers. These proposed revisions relate primarily to the standard for BAT and to a minor extent PSES.

1.2 Regulatory History

EPA first issued a steam electric ELG in 1974, with subsequent revisions in 1977 and 1982. These limitations included requirements on once-through cooling water, cooling tower blowdown, fly ash transport water, BA transport water, metal cleaning waste, coal pile runoff, and low-volume waste sources. Requirements do not apply to discharges from generating units that primarily use nonfossil or nonnuclear fuel sources (*e.g.,* wood waste, municipal solid waste).

In 2015, EPA finalized new requirements for multiple wastestreams generated by new and existing steam electric power plants: BA transport water, CRL, FGD wastewater, flue gas mercury control wastewater, fly ash transport water, and gasification wastewater. Seven petitions for review of the 2015 rule were filed in various circuit courts by industry members, environmental groups, and drinking water utilities. In April 2017, in response to petitions from Utility Water Act Group and the Small Business Administration, EPA postponed compliance dates for the 2015 rule.

On August 11, 2017, the EPA Administrator announced a decision to review and revise BAT requirements for FGD wastewater and BA transport water. The Fifth Circuit Court of Appeals granted EPA's request to sever and hold in abeyance aspects of litigation related to those two wastestreams. The Fifth Circuit Court of Appeals continued to review litigation related to legacy wastewater and leachate. In a decision on April 12, 2019, the court vacated limitations on both legacy wastewater and leachate as arbitrary and capricious under the Administrative Procedure Act and unlawful under the CWA.

On August 31, 2020, EPA finalized a revision to the regulations for the steam electric power generating category that established revised effluent limitations for FGD wastewater and BA transport water. This 2020 rule revised the technology basis for FGD wastewater and BA transport water, established a new compliance date, revised the FGD Voluntary Incentive Program (VIP), and established additional subcategories. See the *Supplemental Technical Development Document for Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (EPA-821-R-20-001) for details related to the 2020 rule.

1.3 Other Key Regulatory Actions Affecting Steam Electric Power Generating

Multiple EPA offices are taking actions to reduce emissions, discharges, and other environmental impacts associated with steam electric power plants. EPA made every effort to appropriately account for other rules affecting the industry in its analysis for the proposed rule. This section provides a brief overview of recent changes to the regulatory requirements for steam electric power plants.

- Coal Combustion Residuals Disposal (CCR) rule: On April 17, 2015, EPA promulgated the Disposal of Coal Combustion Residuals from Electric Utilities final rule (2015 CCR rule). This rule finalized national regulations to provide a comprehensive set of requirements for the safe disposal of coal combustion residuals (CCR), commonly referred to as coal ash, from steam electric power plants. The final 2015 CCR rule was the culmination of extensive study on the effects of coal ash on the environment and public health. The rule established 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 established requirements for the management and disposal of coal ash, including requirements designed to prevent leaking of contaminants into groundwater, blowing of contaminants into the air as dust, and the catastrophic failure of coal ash surface impoundments. The 2015 CCR rule also set recordkeeping and reporting requirements, as well as requirements for each plant to establish and post specific information to a publicly accessible website. The rule also established requirements to distinguish between the beneficial use of CCR from disposal.

  As a result of the D.C. Circuit Court decisions in Utility Solid Waste Activities Group v. EPA, 901 F.3d 414 (D.C. Cir. 2018), and Waterkeeper Alliance Inc. et al. v. EPA, No. 18-1289 (D.C. Cir. filed March 13, 2019), the Administrator signed two rules: A Holistic Approach to Closure Part A: Deadline to Initiate Closure and

Enhancing Public Access to Information (CCR Part A rule) on July 29, 2020, and A Holistic Approach to Closure Part B: Alternate Liner Demonstration (CCR Part B rule) on October 15, 2020. EPA finalized five amendments to the 2015 CCR rule which continue to impact the wastewaters covered by this ELG. First, the CCR Part A rule established a new deadline of April 11, 2021, for all unlined surface impoundments, as well as those surface impoundments that failed the location restriction for placement above the uppermost aquifer, to stop receiving waste and begin closure or retrofitting. EPA established this date after evaluating the steps that owners and operators need to take for surface impoundments to stop receiving waste and begin closure, and the timeframes needed for implementation. (This would not affect the ability of plants to install new, composite-lined surface impoundments.) Second, the Part A rule established procedures for plants to obtain approval from EPA for additional time to develop alternative disposal capacity to manage their wastestreams (both coal ash and noncoal ash) before they must stop receiving waste and begin closing their coal ash surface impoundments. Third, the Part A rule changed the classification of compacted-soil-lined and clay-lined surface impoundments from lined to unlined. Fourth, the Part B rule finalized procedures potentially allowing a limited number of facilities to demonstrate to EPA that, based on groundwater data and the design of a particular surface impoundment, the unit ensures there is no reasonable probability of adverse effects to human health and the environment. Should such a submission be approved, these CCR surface impoundments would be allowed to continue to operate.

As explained in the 2015 and 2020 ELG rules, the ELGs and CCR rules may affect the same electric generating unit (EGU) or activity at a plant. Therefore, when EPA finalized the ELG and CCR rules in 2015, and revisions to both rules in 2020, the Agency coordinated the ELG and CCR rules to minimize the complexity of implementing engineering, financial, and permitting activities. EPA considered the interaction of these two rules during the development of this proposal. EPA's analysis builds in the final requirements of these rules in the baseline accounting for the most recent data provided under the CCR rule reporting and recordkeeping requirements. This is further described in Section 3.3. For more information on the CCR Part A and Part B rules, including information about their ongoing implementation, visit www.epa.gov/coalash/coal -ash-rule.

- Air Pollution Rules and Implementation: EPA is taking several actions to regulate a variety of conventional, hazardous, and greenhouse gas (GHG) air pollutants, including actions to regulate the same steam electric plants subject to Part 423. Other actions impact steam electric plants indirectly when implemented by states. In light of these ongoing actions, EPA has worked to consider appropriate flexibilities in this proposed ELG rule to provide certainty to the regulated community while ensuring the statutory objectives of each program are achieved. Furthermore, to the extent that these actions are finalized and already impacting steam electric plant operations, EPA has accounted for these changed operations in its IPM modeling discussed in the preamble.
    - The Revised Cross State Air Pollution Rule Update and the Proposed Good Neighbor Plan for the 2015 Ozone National Ambient Air Quality Standards. EPA recently completed a rulemaking to address "good neighbor" obligations for the 2008 ozone national ambient air quality standards (NAAQS) and proposed a rulemaking in 2022 with respect to the same statutory obligations for the 2015 ozone NAAQS. These actions implement the Clean Air Act's (CAA's) prohibition on emissions that significantly contribute to nonattainment or interfere with maintenance of the NAAQS in other states.

      On April 30, 2021, EPA published the final Revised Cross-State Air Pollution Rule (CSAPR) Update, 86 FR 23054, which resolved 21 states' good neighbor obligations for the 2008 ozone NAAQS, following the remand of the 2016 CSAPR Update (81 FR 74504) in Wisconsin v. EPA, 938 F.3d 308 (D.C. Cir. 2019). Between them, these two rules establish the Group 2 and Group 3 market-based emissions trading programs for 22 states in the eastern United States for emissions of oxides of nitrogen (NO_X) from fossil fuel-fired EGUs during the summer ozone season.

      On February 28, 2022, the Administrator signed a proposed rule, Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standards, 87 FR 20036 (Apr. 6, 2022) (also called the Good Neighbor Plan). This proposed rule includes further ozone-season NO_X pollution reduction requirements for fossil fuel-fired EGUs to address 25 states' good neighbor obligations for the 2015 ozone NAAQS. The proposed rule would establish an enhanced Group 3 market-based emissions trading program with NOX budgets for EGUs in those 25 states, beginning in 2023. Further information about this proposal is available on EPA's website.[1]

- Clean Air Act Section 111 Rule. On October 23, 2015, EPA finalized New Source Performance Standards (NSPSs) for emissions from new, modified, and reconstructed fossil fuel-fired EGUs under CAA section 111(b). Specifically, the 2015 NSPS established separate standards for emissions of CO2 from newly constructed, modified, and reconstructed fossil fuel-fired electric utility steam generating units (i.e., utility EGUs and integrated gasification combined cycle units) and from newly constructed and reconstructed fossil fuel-fired stationary combustion turbines. The standards set in the 2015 NSPS reflected the degree of emission limitation achievable through application of the best system of emission reduction that EPA determined to have been adequately demonstrated for each type of unit and was codified in 40 CFR part 60, subpart TTTT. EPA is currently reviewing the 2015 NSPS—including new technologies to mitigate GHG emissions from new, modified, and reconstructed stationary combustion turbines—and will, if warranted, propose to revise the NSPSs in an upcoming rulemaking.

  On August 3, 2015, under CAA section 111(d), EPA promulgated its first emission guidelines regulating emissions from existing fossil fuel-fired EGUs in the Clean Power Plan (CPP) (40 CFR part 60, subpart UUUU). The CPP was subsequently stayed by the U.S. Supreme Court. On June 19, 2019, EPA promulgated new emission guidelines, known as the Affordable Clean Energy (ACE) Rule (40 CFR part 60, subpart UUUUa), and issued a repeal of the CPP. On January 19, 2021, the U.S. Court of Appeals for the D.C. Circuit vacated the ACE Rule and remanded the rule to EPA for further consideration consistent with its decision. The Supreme Court then overturned portions of the D.C. Circuit Court's decision in West Virginia v. EPA, No. 20-1530, in June 2022. EPA is now considering the implications of the Supreme Court's decision and is undertaking a new rulemaking to establish new emission guidelines under CAA section 111(d) to limit emissions from existing fossil fuel-fired EGUs.

- Mercury and Air Toxics Standards Rule. After considering costs, EPA recently proposed to reaffirm the determination that it is appropriate and necessary to regulate hazardous air pollutants (HAPs), including mercury, from coal- and oil-fired steam generating power plants. These regulations are known as the Mercury and Air Toxics Standards (MATS) for power plants. The proposed MATS action would revoke a 2020 finding that it is not appropriate and necessary to regulate coal- and oil-fired power plants under CAA section 112, but which did not disturb the underlying MATS regulations. The MATS proposal would ensure that coal- and oil-fired power plants continue to control emissions of toxic air pollution, including mercury.

- National Ambient Air Quality Standards Rules for Particulate Matter. EPA is currently reconsidering a December 7, 2020, decision to retain the primary (health-based) and secondary (welfare-based) NAAQS for particulate matter (PM).[2] EPA is reconsidering the December 2020 decision because available scientific evidence and technical information indicate that the current standards may not be adequate to protect public health and welfare, as required by the CAA.

[1] See www.epa.gov/csapr/good-neighbor-plan-2015-ozone-naaqs.

[2] See www.epa.gov/newsreleases/epa-reexamine-health-standards-harmful-soot-previous-administration-left-unchanged.

2. Data Collection Activities

EPA collected and evaluated information from various sources while developing the 2015 and 2020 rules, as described in Section 3 of the 2015 Technical Development Document (2015 TDD) and Section 2 of the 2020 Supplemental TDD, respectively. EPA collected additional supplemental data for the 2023 proposal to update the industry profile; identify the power plants affected by the rule; reevaluate industry subcategorization; update plant-specific operations and wastewater characteristics; determine the technology options; and estimate the compliance costs, pollutant loadings and removals, and non-water-quality environmental impacts of the technology options. This section briefly summarizes past data collection activities for the 2015 and 2020 rules (Section 2.1) and describes new data collection activities for flue gas desulfurization (FGD) wastewater, bottom ash (BA) transport water, legacy wastewater, and combustion residual leachate (CRL) for the 2023 proposal (Sections 2.2 through 2.4).

2.1 Summary of Data Collection for the 2015 and 2020 Rulemakings

For the 2015 and 2020 rules, EPA collected and obtained information on the steam electric power generating industry from multiple sources including a detailed study of the industry, an information collection request (ICR), site visits, field sampling, Clean Water Act (CWA) section 308 industry requests, and voluntary requests as detailed below.

- *Detailed study.* EPA studied the steam electric power generating industry between 2005 and 2009. Data collection included multiple site visits and six wastewater sampling episodes at steam electric power plants, a screener questionnaire sent to 9 companies (operating 30 coal-fired power plants), publicly available data sources, and outreach with EPA program offices, other governmental groups and industry stakeholders. The detailed study focused on wastewater from coal ash handling operations and from FGD air pollution control systems.
- *2009 Steam Electric Survey.* EPA administered a survey to approximately 700 power plants to collect technical information related to wastewater generation and treatment, as well as 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 revising the effluent limitations guidelines and standards (ELGs) for the steam electric category, in addition to costs, loadings, and other rulemaking analyses.
- *Site visits.* EPA conducted 73 site visits at steam electric power plants in 18 states between December 2006 and November 2014 to gather information about each plant's operation, pollution prevention and wastewater treatment options, and whether the plant was appropriate to include in the field sampling program. After promulgating the 2015 rule, between October and December 2017, EPA conducted another seven site visits to power plants in five states to update information on methods for managing FGD wastewater and BA transport water. EPA used data from site visits to update industry profile data; learn more about pollution control and wastewater treatment options evaluated as part of the rulemakings; and inform costs, loadings, and other rulemaking analyses.
- *Field sampling program.* For the 2015 rule, EPA conducted 4-day sampling episodes at seven U.S. plants to obtain wastewater characterization data and wastewater treatment technology performance data. EPA used these data in combination with other industry-supplied data to evaluate wastewater discharges from steam electric power plants and to evaluate technology options for managing these wastewaters. The sampling program primarily focused on wastewaters from wet FGD systems. EPA also conducted a 3-day sampling episode at Enel's Federico II Power Plant (Brindisi), located in Brindisi, Italy, to characterize an FGD wastewater treatment system consisting of chemical precipitation followed by evaporation.
- *CWA 308 monitoring program.* For the 2015 rule, EPA required four plants to collect four consecutive days of samples at two to four sampling locations chosen to characterize coal-gasification wastewaters, carbon capture wastewaters, and the treatment of FGD wastewater and coal-

gasification wastewater by vapor-compression evaporation. These data were used to supplement the sampling data collected during the field sampling program.

- *Voluntary requests.* Following the 2015 rule, EPA invited seven steam electric power plants to participate in a voluntary BA transport water sampling program. EPA requested information from steam electric power plants operating impoundments that predominantly contain BA transport water. Plants were asked to provide sampling data for ash impoundment effluent and untreated BA transport water (*i.e.,* ash impoundment influent). Two plants chose to participate in the voluntary BA sampling program.
- *Other data sources.* EPA used Electric Power Research Institute (EPRI) reports, data from the U.S. Department of Energy's (DOE's) Energy Information Administration (EIA), information from literature and internet searches, and information from environmental groups to supplement the industry profile; learn more about pollution control and wastewater treatment options evaluated as part of the rulemakings; and inform costs, loadings, and other rulemaking analyses.

2.2 Site Visits and Industry-Submitted Data

In support of the latest rule revision, EPA participated in a virtual site visit with representatives from Duke Energy in 2021. The visit focused on Duke Energy's coal-fired generating units and the treatment and management of BA transport water, FGD wastewater, legacy wastewater, and CRL since the 2020 rule. EPA also gathered information on steam electric power generating processes, wastewater treatment technologies, and wastewater characteristics directly from the industry through a CWA 308 request, two voluntary requests, and other industry data provided during the 2023 proposal. EPA used this information to learn more about the performance of FGD, CRL, and legacy wastewater treatment systems and obtain information useful for estimating the cost of installing candidate treatment technologies. EPA also used this information to learn more about BA system performance, characterization and quantification of the overflow and purge from remote mechanical drag systems (MDS) installations, and treatment technologies and pilot testing associated with CRL and legacy wastewater. EPA used this information to supplement the data collected in support of the 2015 and 2020 rules.

2.2.1 CWA 308 Request

In January 2022, EPA requested the following information for coal-fired power plants from three steam electric power companies:

- FGD wastewater installations: thermal technology; membrane filtration technology; paste, solidification, or encapsulation of FGD wastewater brine; electrodialysis; and electrocoagulation.
- Overflow from an MDS, compact submerged conveyor (CSC), or remote MDS installation including purge rate and management from remote MDS, as well as any pollutant concentration data to characterize the overflow or purge.
- CRL treatment from on-site or off-site testing (full-, pilot-, or laboratory-scale).
- On-site or off-site testing (full-, pilot-, or laboratory-scale) and/or implementation of treatment technologies associated with surface impoundment decanting or dewatering treatment.
- Costs associated with these technologies.

After meeting with these three companies, EPA sent four other power companies a request inviting them to provide the same data described above.

2.2.2 Voluntary Industry Sampling Requests

In December 2021, EPA invited eight steam electric power companies to participate in a voluntary request program. The specific voluntary requests are outlined below.

- Existing CRL data consistent with EPA's request.

- Untreated and treated samples of CRL on the sampling schedule laid out in EPA's request.
- Grab samples of landfill solids and leachate samples analyzed using EPA Methods 1313 and 1316 (leaching evaluations).

2.3 Technology Vendor Data

EPA gathered data from technology vendors through presentations, conferences, site visits, meetings, and email and phone contacts regarding the FGD wastewater, BA handling, CRL, and legacy wastewater technologies used in the industry. EPA used the data to inform the development of the technology costs and pollutant removal estimates for FGD wastewater, BA transport water, CRL, and legacy wastewater. For the development of the 2015 and 2020 rules, EPA participated in multiple technical conferences and reviewed the papers presented for information relevant to the proposed rule.

2.3.1 FGD Wastewater, CRL, and Legacy Wastewater Treatment

EPA contacted companies that manufacture, distribute, or install various components of biological wastewater treatment, membrane filtration, or thermal evaporation systems for FGD wastewater, CRL, and legacy wastewater treatment. EPA also contacted consulting firms that design and implement treatment technologies associated with these wastestreams. The vendors and consulting firms provided the following types of information for EPA's analyses:

- Operating details.
- Performance data where available.
- Equipment used in the system.
- Estimated capital and operation and maintenance (O&M) costs.
- System energy requirements.
- Timeline to bid, procure, and install.
- Changes in the industry since 2020 including retirements or fuel conversions, new FGD installations, and planned future installations.

2.3.2 BA Handling

EPA contacted vendors as well as consulting firms that design and implement BA handling systems. The vendors and consulting firms provided the following types of information for EPA's analyses:

- Systems available for reducing or eliminating ash transport water.
- Equipment, modifications, and demolition required to convert wet sluicing systems to dry ash handling or high recycle rate (HRR) systems.
- Equipment that can be reused as part of the conversion from wet to dry handling or in a HRR system.
- Outage time estimated for installing the different types of ash handling systems.
- Maintenance estimated for each type of system.
- Estimated capital and O&M costs.
- Changes in the industry since 2020 including retirements or fuel conversions, new BA installations, and planned future installations.
- Purge from complete recycle systems, purge from under-boiler mechanical drag systems, and purge wastewater characteristics.

2.4 Other Data Sources

EPA gathered information on steam electric power generating processes, wastewater treatment, wastewater characteristics, and regulations from sources including EPRI, Department of Energy (DOE), literature and internet searches, notices of planned participation (NOPPs), environmental groups, residents of affected communities, state and local governments, tribes, and reporting by utilities via the "CCR Compliance Data and Information" websites required by the Coal Combustion Residuals (CCR) rule. Sections 2.4.1 through 2.4.6 summarize the data collected from these additional sources.

2.4.1 EPRI

EPRI conducts studies funded by the steam electric power generating industry to evaluate and demonstrate technologies that can potentially remove pollutants of concern from wastestreams or eliminate wastestreams using zero discharge technologies. EPA reviewed reports—listed in Table 1—that EPRI voluntarily provided, or that were provided in CWA 308 responses. These reports contained information relevant to characteristics of FGD wastewater, CRL and legacy treatment pilot studies, BA transport water characterization and BA handling practices.

Table 1. EPRI Reports and Studies Reviewed by EPA for the 2023 Proposal

Title of Report/Study	Date Published	Document Control Number
Effects of Alkaline Sorbents and Mercury Controls on Fly Ash and FGD Gypsum Characteristics and Implications for Disposal and Use	2014	SE10395
Coal Combustion Residuals Leachate Management: Characterization of Leachate Quantity and Evolution of Leachate Minimization and Management Methods	2015	SE10386
Coal Combustion Residuals Leachate Management: Characterization of Leachate Quality	2016	SE10387
Evaporation Treatment of Flue Gas Desulfurization Wastewater	2017	SE06970
Landfill Leachate Characterization, Management and Treatment Options	2017	SE06959
Brine Encapsulation Laboratory Study	2018	SE10296
Wastewater Encapsulation Testing References: Encapsulating Co-Management of Liquid Waste with Combustion Byproducts at Bench and Field Scale	2018	SE10295
Mercury, Methylmercury, and Selenium Interactions in Freshwater Fish	2018	SE10388
Performance Evaluation of the Vacom Thermal Vapor Recompression Technology for FGD Wastewater Treatment	2019	SE10389
Membrane Treatment Guidelines	2019	SE10297
Considerations for Treating Flue Gas Desulfurization Wastewater Using Membrane and Paste Encapsulation Technologies	2019	SE10396
Studies on the Encapsulation of Brine Generated from a Process Using Selective Electrodialysis Reversal		SE10397
Landfill Leachate Treatment Study: Evaluations of Membrane, Evaporation, and Encapsulation Technologies	2020	SE10385
The Impacts of High Salinity Wastewater Chemistry and Fly Ash Reactivity on Encapsulation	2020	SE10298
Thermal Water/Wastewater Treatment System Chemistry Guidelines	2020	SE10390
Real-Time Online Membrane Monitor Demonstration	2020	SE010300
Understanding Chemical Reactions and Mineral Additives for Wastewater Encapsulation	2020	SE10299

Table 1. EPRI Reports and Studies Reviewed by EPA for the 2023 Proposal

Title of Report/Study	Date Published	Document Control Number
Conference Proceedings of the 2020 Virtual Selenium Summit	2020	SE10391
FGD Wastewater Treatment Testing Using a Saltworks Flex EDR Selective Electrodialysis Reversal System Technology	2020	SE10398
Quantifying Leachate Volumes at Four Coal Combustion Product Landfills in the Southeastern United States	2021	SE10392
Review of Coal Combustion Product Leaching	2021	SE10393
Review of Established and Emerging Boron Treatment Technologies for Water at Coal Combustion Product Sites	2021	SE10399
Water Flow in Coal Combustion Products and Drainage of Free Water	2021	SE10394
Coal Combustion Product Landfill Terminology and Water Management Fundamentals	2021	SE10400

2.4.2 Department of Energy

EPA compiled information on steam electric power plants from EIA's Form EIA-860, *Annual Electric Generator Report,* and Form EIA-923, *Power Plant Operations Report.* The data collected in Form EIA-860 concern the design and operation of generators at plants, while data collected in Form EIA-923 concern the design and operation of the entire plant. EPA has been using relevant data from EIA-923 and EIA-860 from 2009 to 2020 (U.S. DOE, 2020, 2020a). EPA used these data to update the industry profile from the 2020 rule, including commissioning dates, energy sources, capacity, net generation, operating statuses, planned retirement dates, ownership, and pollution controls of the generating units. Consistent with the 2020 rule analyses, EPA also used data reported to DOE to estimate bromide loadings from FGD discharges, including fuel consumption by coal type and coal purchases by county and coal type.

2.4.3 Office of Land and Emergency Management

The 2015 CCR rule established requirements for the safe disposal of CCRs from coal-fired steam electric power plants. The CCR rule requires owners or operators of CCR surface impoundments and landfills to record compliance with the rule's requirements and maintain a publicly available website of compliance information.

EPA used plant-specific information on CCR landfills and surface impoundments from EPA's Office of Land and Emergency Management (OLEM) as part of its CCR leachate in groundwater and legacy analyses. In April 2022, EPA's OLEM provided the Office of Water with publicly available CCR compliance information for 772 CCR management units, corresponding to 289 facilities, subject to the CCR Part A rule requirements (U.S. EPA, 2022).

2.4.4 Power Company CCR Websites

As described in Section 2.4.3, the 2015 CCR rule established requirements for the safe disposal of CCRs from coal-fired steam electric power plants and requires owners or operators of CCR surface impoundments and landfills to record compliance with the rule's requirements and maintain a publicly available website of compliance information. EPA searched these websites for CCR management-specific documents including:

- Closure plans/reports
- Liner certifications
- Run-on/run-off control plans
- Annual inspection reports

- Annual groundwater monitoring plans and corrective action reports
- Groundwater monitoring system design reports

See EPA's memoranda *Evaluation of Potential CRL in Groundwater* (U.S. EPA, 2023a) and *Legacy Wastewater at CCR Surface Impoundments* (U.S. EPA, 2023b) for more details on how this information was used as part of EPA's CCR leachate in groundwater and legacy analyses.

2.4.5 Literature and Internet Searches

EPA conducted literature and internet searches to gather information on FGD wastewater, CRL, and legacy wastewater treatment technologies, including information on pilot studies, applications in the steam electric power generating industry, and implementation costs and timeline. EPA also used internet searches to identify or confirm reports of planned plant/unit retirements or reports of planned unit conversions to dry or HRR ash handling systems. EPA used industry journals and company press releases obtained from Internet searches to inform the industry profile and process modifications occurring in the industry.

2.4.6 Intergovernmental and Tribal Listening Sessions

As part of the supplemental rulemaking process, EPA held consultation and coordination proceedings with intergovernmental agencies and Tribal governments. Consultations pursuant to Executive Order 13132, entitled "Federalism," and the Unfunded Mandates Reform Act (UMRA) were held January 27, 2022. EPA received five sets of unique written comments after the meeting, including two comments from trade associations representing public water systems. These comments generally recommended more advanced treatment to reduce the pollutants making their way downstream to intakes for government-owned public water systems or, alternatively, to empower states to more effectively address these discharges. The remaining three comments came from the American Public Power Association and two of its member utilities. These comments recommended the retention of existing limitations and subcategories, a careful consideration of the CRL definition and BAT, and a compliance pathway for utilities that installed or are in the process of installing technologies to comply with the 2015 and 2020 rules compliant technologies. EPA also held listening sessions via webinars with Tribal representatives on February 1 and 9, 2022. Following these consultations, EPA received written comments from three tribes: the Sault Ste. Marie Tribe of Chippewa Indians, the Mille Lacs Band of Ojibwe, and the Little Traverse Bay Bands of Odawa Indians. These comments conveyed the importance of historical tribal waters and rights (e.g., fishing, trapping) and recommended more stringent technological controls or encouraged retirement or fuel conversion of old coal-fired units to protect those rights.

2.4.7 Communities

In support of its environmental justice analysis (EJA), EPA conducted a screening-level analysis of pollution exposures to potentially affected communities and identified nine communities with EJ concerns. EPA planned outreach to community members to discuss ideas and strategies for limiting pollution from steam electric power plants, concerns related to these plants or other sources of pollution including impacts to nearby rivers, lakes, and streams or drinking water; and community health, social, and economic concerns. EPA conducted initial outreach to local environmental and community development organizations, local government agencies, and individual community members. Between May and September 2022, EPA held listening sessions with community members in five of the identified communities. Each meeting began with a presentation providing background information about the proposed supplemental rulemaking before opening the meeting for questions and comments from community members.

- EPA received a broad range of input from individuals in these communities on regulatory preferences, environmental concerns, human health and safety concerns, economic impacts, cultural/spiritual impacts, ongoing communication/public outreach, and interest in other EPA actions. Three broad themes conveyed consistently across communities included:

- Community members perceive harmful impacts from steam electric power plants and desire more stringent regulations to reduce these harmful impacts.
- Community members desire more transparency to overcome their decreasing trust in the regulated plants and state regulatory agencies.
- Community members would prefer increased communication to understand the compliance of steam electric power plants.

Commenters also raised concerns unique to each community. For example, members of the Navajo Nation discussed with EPA the spiritual and cultural impacts to the community from pollution related to steam electric power plants. In Jacksonville, Florida, community members raised concerns regarding tidal flows of pollution upstream and storm surges during extreme weather events that cause additional challenges in their community. See the *Environmental Justice Analysis for Proposed Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* for more details on these meetings (U.S. EPA, 2023c).

2.4.8 Notices of Planned Participation (NOPPs)

The 2020 rule required facilities to file a notice of planned participation (NOPP) with their permitting authority no later than October 13, 2021, where the facility wished to participate in the low utilization electric generating unit (LUEGU) subcategory, the permanent cessation of coal combustion subcategory, or in the VIP. While EPA did not require that a copy be provided to the agency, EPA obtained a number of these filings through various means including their standard permit review process, a facility providing EPA a courtesy copy, EPA asking a state for their NOPPs, or environmental groups tracking NOPPs and sharing the information they had collected with EPA. EPA is currently aware of NOPPs covering 90 EGUs at 38 plants. Of these, four EGUs (at two plants) have requested participation in the LUEGU subcategory, an additional 12 EGUs (at four plants) have requested participation in the 2020 rule VIP, and the remaining 74 EGUs (at 33 plants) have requested participation in the permanent cessation of coal combustion subcategory (U.S. EPA, 2023d). EPA cautions that these counts are not a comprehensive picture of facilities' plans. See Preamble Section VI.B for more information about NOPPs.

2.5 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 precautions 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 found it necessary to withhold from disclosure some data not directly claimed as CBI because the release of these data could indirectly reveal CBI. Where necessary, 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 explain the basis for the rule and provide the opportunity for public comment without compromising data confidentiality.

3. Current State of the Steam Electric Power Generating Industry

For the 2015 rule, EPA generated a comprehensive industry profile using 2009 Department of Energy (DOE) Energy Information Administration (EIA) data, data gathered through EPA's 2009 *Questionnaire for the Steam Electric Power Generating Effluent Guidelines* (Steam Electric Survey) data, and Census Bureau data from 2007. See Section 4 of the 2015 rule's Technical Development Document (TDD). For the 2020 rule, EPA updated the comprehensive profile to account for current plant operations and plans for future modifications. See Section 3 of the 2020 Supplemental TDD.

For the proposed rule, EPA updated the comprehensive profile, evaluated changes in wastewater management practices, and assessed impacts from other regulations affecting steam electric power plants since the 2020 rule analysis. This section describes the current state of the steam electric power generating industry, as it relates to the technical aspects of this 2023 proposal:

- Changes in the steam electric power plant population (Section 3.1).
- Current information on evaluated wastestreams (Section 3.2).
- Other regulations affecting the steam electric power generating industry (Section 3.3).

3.1 Changes in the Steam Electric Power Generating Industry Since the 2020 Rule

The steam electric power generating industry is dynamic: the Agency recognizes that industry demographics and plant operations have changed after the 2020 rule analyses were completed.[3] Therefore, EPA collected information on current plant operations and plans for future modifications to augment industry profile data collected for the 2015 and 2020 rules. This section discusses changes in the number and operating status of coal-fired electric generating units (EGUs) and updates to wet flue gas desulfurization (FGD) systems, FGD wastewater treatment, bottom ash (BA) handling systems, and coal combustion residual (CCR) landfills.

EPA gathered information from public sources, including company announcements and EIA data, to account for the following types of operation changes that have occurred or been announced since the 2020 rule analyses:

- Commissioning of new coal-fired EGUs.
- Retirement of coal-fired EGUs.[4]
- Fuel conversions of coal-fired EGUs from coal to another fuel source, such as natural gas or hydrogen fuel cells (e.g., natural gas).
- Installation of wet FGD systems.
- Modification or upgrade of FGD wastewater treatment systems.

[3] EPA's 2020 rule analyses *accounted for all industry profile changes announced and verified as of February 2020 that are in effect until 2028.*

[4] For the purposes of this analysis, EPA accounted for EGUs that will be indefinitely removed from service (i.e., idled or mothballed) as retirements. See the preamble for discussion of EPA's evaluation of coal-fired EGUs nearing end of life.

- Installation of, or conversion to, dry, closed-loop recycle, or high recycle rate (HRR) wet-sluicing BA handling systems.[5]
- Installation of new CCR landfills.

EPA identified 171 coal-fired EGUs at 91 plants from the 2020 rule profile with at least one significant change in operation taking place by December 31, 2028 (the date by which the final rule would be fully implemented). Table 2 presents the count of steam EGU and plants, broken out by type of operation change.

Table 2. Industry Profile Updates Since February 2020 by Type of Change in Operation

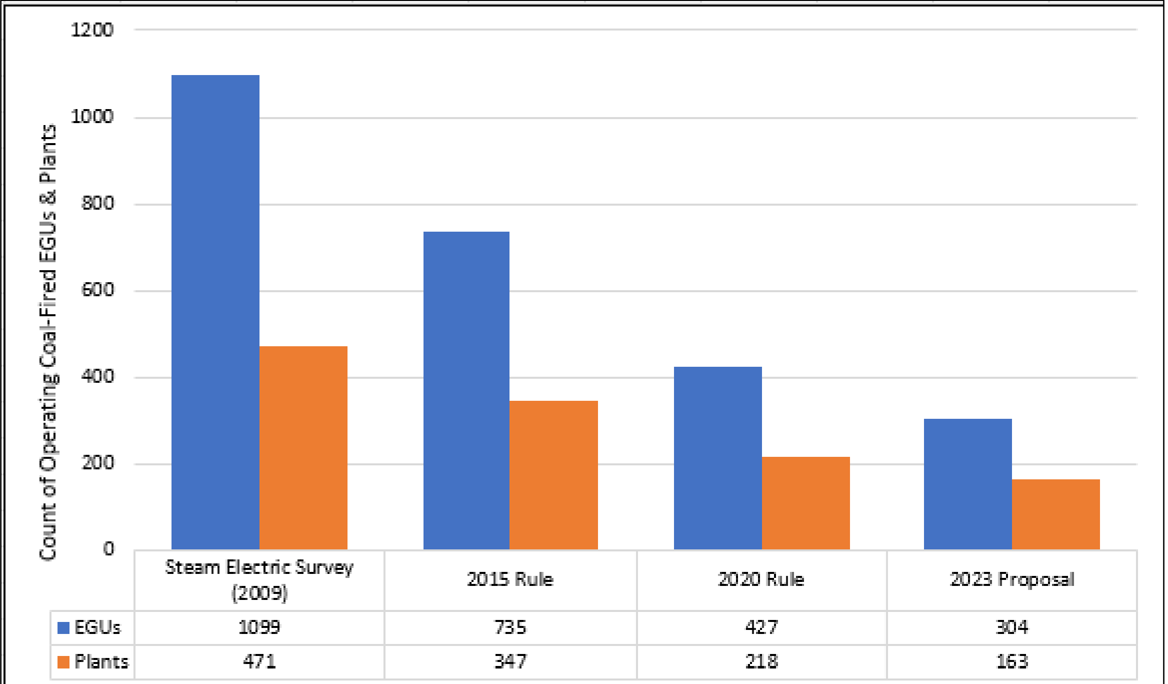
Change in Operation	Count	
	EGUs	Plants
Retirement of coal-fired EGU	158	85
Fuel conversion to non-coal fuel type	13	8
Modification or upgrade of FGD wastewater treatment system[a]	0	0
Installation of new CCR landfill	NA	8

a – EPA identified an upgrade to an FGD wastewater treatment system at one coal-fired power plant, corresponding to four EGUs; however, this upgrade was confirmed after the profile for this proposed rule was finalized on December 31, 2021 (U.S. EPA, 2023d).

As shown in Figure 1, there has been an overall decrease in the number of EGUs operating in the industry. The population of coal-fired EGUs and plants decreased to 304 EGUs at 163 plants, 29 percent fewer EGUs than the 2020 rule population. Figure 1 illustrates the change in the number of operating coal-fired EGUs and plants since the Steam Electric Survey, 2015 rule, 2020 rule, and 2023 proposed rule.

Section 5 and Section 6 describe how EPA accounted for the changes in operation identified in Table 2 in estimating compliance costs, pollutant loadings, and pollutant removals for the proposed rule. More information on the specific coal-fired EGUs and plants identified as implementing each type of operation change is discussed in the memorandum titled *Update to Industry Profile for the 2023 Steam Electric Effluent Guidelines Proposed Rule* (U.S. EPA, 2023d).

[5] For this discussion, dry BA handling systems include all systems that do not generate BA transport water.



Note: The 2015 rule analyses accounted for profile changes expected to occur before December 31, 2023 (the latest date that power plants were subject to the established Best Available Technology Economically Achievable (BAT) effluent limitations), whereas the 2020 rule and 2023 proposed rule account for changes expected to occur before December 31, 2028.

Figure 1. Change in Population of Coal-Fired EGUs and Plants

3.2 Current Information on Evaluated Wastestreams

This section summarizes current information on the generation and discharge of FGD wastewater, BA transport water, CRL, and legacy wastewater that EPA collected for the proposed rule.

3.2.1 FGD Wastewater

As discussed in Section 3.1, EPA updated the industry profile to reflect coal-fired EGUs that will retire, convert fuels, or upgrade FGD wastewater treatment prior to December 31, 2028. Of the 304 coal-fired EGUs at 163 coal-fired power plants in the updated profile, 105 EGUs at 54 plants are serviced by a wet FGD system. EPA estimates EGUs with wet FGD systems have a total generating capacity of 66,270 megawatts (MW), representing approximately 50 percent of the total industry coal-fired capacity.

Figure 2 shows the locations of plants operating wet FGD systems servicing at least one coal-fired EGU. In addition to wet FGD scrubbers, EPA estimates that there are 36 plants operating dry FGD scrubbers servicing at least one coal-fired EGU in the industry. Although dry FGD scrubbers use water in their operation, the water in most systems evaporates and they generally do not discharge wastewater. 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.

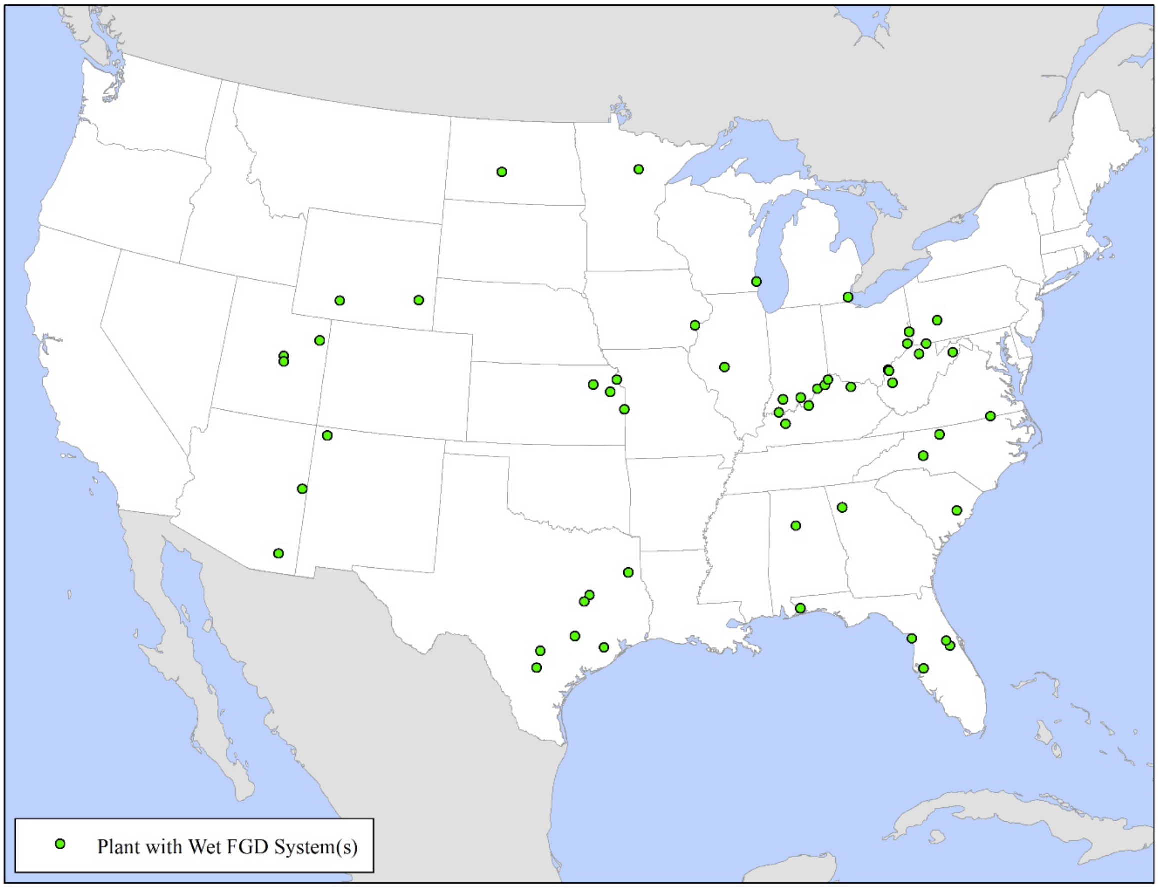


Figure 2. Wet FGD Systems at Steam Electric Power Plants

Although the number of wet FGD systems operated at steam electric power plants has decreased since promulgation of the 2020 rule, current FGD scrubber technologies are the same as those used at the time of the 2015 rule. These wet FGD systems typically use a limestone slurry with forced oxidation to remove SO_2 from flue gas from EGUs burning bituminous coal. Often, plants also operate selective catalytic reduction (SCR) systems on these EGUs to reduce nitrogen oxide (NO_x) emissions.

Following promulgation of the 2015 rule, EPA collected new information on air pollution control practices at steam electric power plants that may affect the characteristics of FGD wastewater. Specifically, EPA found that steam electric power plants may add halogens (*e.g.,* bromine, chlorine, or iodine) to reduce mercury air emissions. While all coal contains at least some naturally occurring halogens, steam electric power plant operators can augment coal halogen concentrations at various points in the plant operations to enhance mercury oxidation for mercury capture (*e.g.,* directly injecting halogen during combustion; mixing bromide with coal to produce refined coal; and using brominated activated carbon to control air emissions). Halogens in flue gas at steam electric power plants are captured by wet FGD systems and discharged in FGD wastewater.

Steam electric power plants have conducted on-site testing and/or installed a variety of technologies to treat FGD wastewater, including chemical precipitation, constructed wetlands, zero valent iron cementation, adsorption, ion exchange, and low residence time reduction (LRTR) biological treatment, high residence time reduction (HRTR) biological treatment, advanced membrane filtration, and thermal evaporative systems. EPA has identified that approximately seven percent of steam electric power plants with wet FGD scrubbers have technologies in place able to meet the proposed BAT effluent limitations for

FGD wastewater, including membrane filtration systems or other FGD wastewater management approaches that eliminate the discharge of FGD wastewater altogether. EPA also identified at least eight installations of LRTR or HRTR systems in the steam electric power generating industry (the basis for BAT limitations associated with the 2020 and 2015 FGD wastewater limitations, respectively). EPA identified two domestic installations of spray evaporation technologies treating FGD wastewater and nine installations of spray evaporation systems treating FGD wastewater in Asia. See Section 4 for more details on these treatment technologies employed by some steam electric power plants to treat or reduce FGD wastewater discharges. Table 3 summarizes FGD wastewater discharged by the steam electric power plants included in EPA's costs and loadings analyses.

Table 3. FGD Wastewater Discharges for the Steam Electric Power Plants

FGD Wastewater Discharge Flow Rate					
Number of Plants	Number of EGUs	Total Daily Discharge Purge Flow Rate (MGD)	EGU Average Daily Discharge Purge Flow Rate (MGD per EGU)	Total Annual Discharge Purge Flow Rate (MGY)	EGU Annual Discharge Purge Flow Rate (MGY per EGU)
26	58	35.9	0.619	13,100	226

MGD = million gallons per day.

MGY = million gallons per year.

Note: Counts and flow rates do not include EGUs that will retire or convert fuels by December 31, 2028, and wet FGD systems that began operating after the Steam Electric Survey are excluded from the table.

3.2.2 BA Transport Water

Based on the Steam Electric Survey, approximately two-thirds of coal-fired power plants operated wet BA handling systems in 2009. Some plants operating the wet BA handling systems recycled BA transport water from impoundments, dewatering bins, or other handling systems back to the wet-sluicing system; however, most BA transport water was discharged to surface water. At the time of the Steam Electric Survey, less than 40 percent of EGUs operated dry, closed-loop recycle, or HRR BA handling systems. Because of changes happening in the industry in the years following the Steam Electric Survey, by 2015 more than half of EGUs operated or planned to convert to dry, closed-loop recycle, or HRR BA handling systems.

As discussed in Section 3.1, EPA updated the industry profile and corresponding analyses to account for coal-fired EGUs that will retire, convert fuels, or install dry, closed-loop recycle, or HRR BA handling systems prior to December 31, 2028. Since the 2015 and 2020 rules, more plants have converted or are converting to dry, closed-loop recycle, or HRR BA handling systems, thereby eliminating or minimizing discharge of BA transport water. In addition, based on data from the Steam Electric Survey, EGUs commissioned after 2009 likely operate dry or closed-loop recycle BA handling systems.[6] Further, the number of coal-fired EGUs operating wet sluicing systems has decreased due to plant retirements and fuel conversions. Table 4 presents the count and total generating capacity of the EGUs operating wet sluicing, closed-loop recycle and/or HRR, or dry BA handling systems. For the 2020 rule, EPA estimated that more than 75 percent of EGUs operate either dry, closed-loop recycle, or HRR BA handling systems.[7] Based on conversations with industry, EPA is aware that plants are still working to comply with the 2020

[6] Data from the Steam Electric Survey show that more than 80 percent of EGUs built in the 20 years preceding the survey (1989–2009) installed dry BA handling at the time of construction. Because dry BA technologies are less expensive to operate than wet-sluicing systems and facilitate beneficial use of the BA, it is unlikely that power companies would find it advantageous to install wet-sluicing BA handling systems.

[7] Counts presented in this paragraph and Table 4 do not reflect BA handling conversions expected as a result of the CCR Part A rule.

rule. Figure 3 illustrates the geographic distribution of plants operating the systems noted in Table 4. Plants that operate more than one type of system are shown as wet sluicing (with limited/no recycle or closed-loop/HRR), whichever is applicable.

Table 4. BA Handling Systems for Coal-Fired EGUs

Type of System	Number of Plants	Number of EGUs	Nameplate Capacity (MW)
Wet sluicing system with limited or no recycle	41	116	48,300
Wet sluicing closed-loop/HRR system	32	105	47,500
Dry BA handling system[a]	97	178	69,007
Total	163[b]	304	170,000

Note: Counts and flow rates do not include EGUs that will retire or convert fuels by December 31, 2028. Wet FGD systems that began operating after the Steam Electric Survey are excluded from the table.

a—The dry BA handling system counts presented in this table reflect conversions identified by EPA in the Steam Electric Survey and publicly available information from 2009 or later. Where data were available, EPA tracked the specific types of BA handling conversions, such as MDS and remote MDS. However, EPA identified 35 EGUs, corresponding to 14,100 MW at 14 plants, for which the data confirmed that the plant was not discharging BA transport water but did not confirm the specific type of nondischarging system.

b—Plant counts are not additive because plants may operate multiple types of BA handling systems.

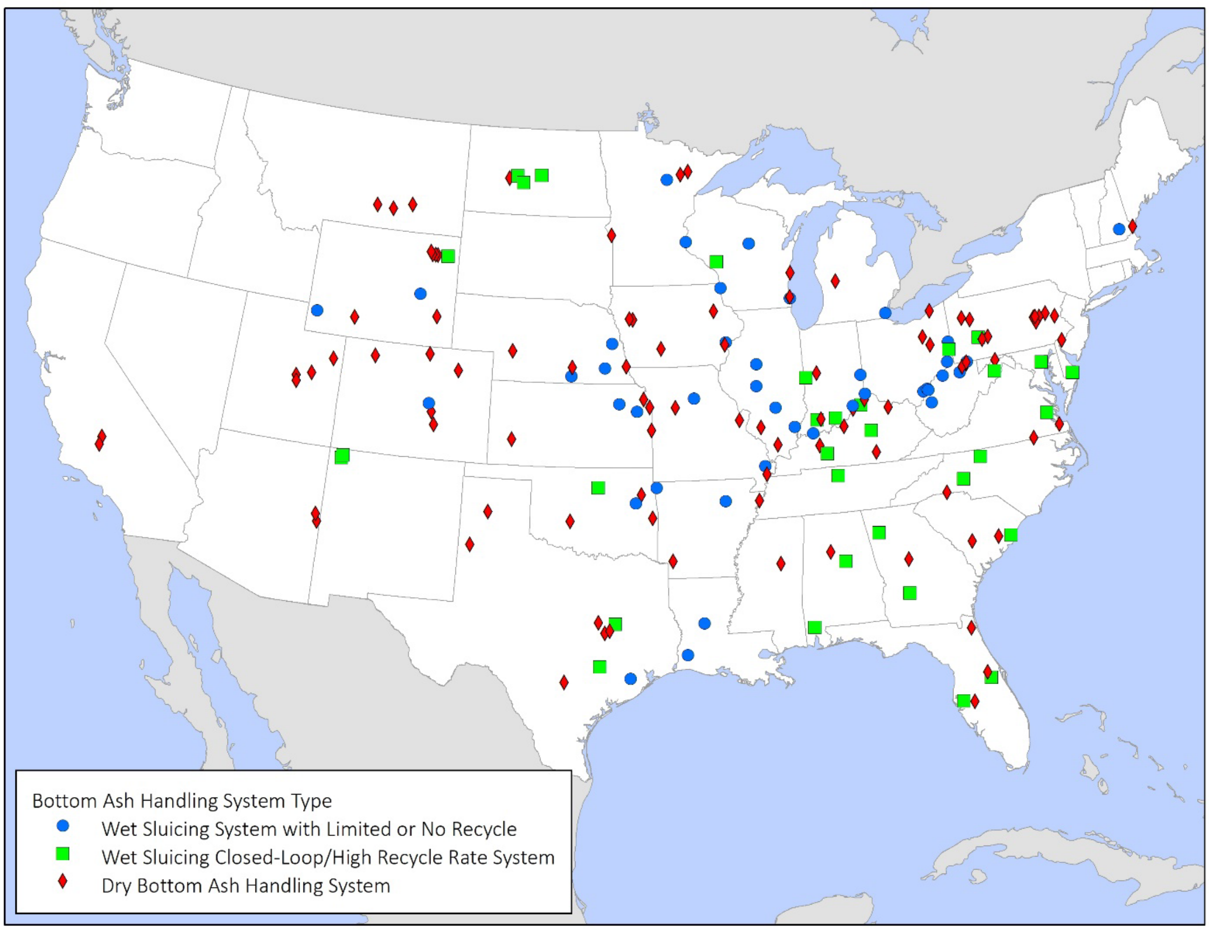


Figure 3. Plant-Level BA Handling Systems in the Steam Electric Power Generating Industry

Table 5 summarizes BA transport water discharges by the steam electric power plants included in EPA's costs and loadings analyses. The estimated flow rates are based on compliance with the 2020 rule, which may represent full sluicing operations or a 10 percent allowable purge.

Table 5. BA Transport Water Discharges for the Steam Electric Power Plants

BA Wastewater Discharge Flow Rate					
Number of Plants	Number of EGUs	Total Daily Discharge Flow Rate (MGD)	EGU Average Daily Discharge Flow Rate (MGD per EGU)	Total Annual Discharge Flow Rate (MGY)	EGU Annual Discharge Flow Rate (MGY per EGU)
36	90	65.9	0.732	24,000	267

MG = million gallons per day.

MGY = million gallons per year.

3.2.3 CRL

EPA used data from the 2009 Steam Electric Survey to identify the population of landfills containing combustion residuals that collect and discharge leachate to surface waters or publicly owned treatment works (POTWs) (U.S. EPA, 2015). For the 2023 proposal, EPA updated this data set to remove plants that intend to retire all coal-fired EGUs as of December 31, 2023 and add plants that have constructed new landfills since 2015.[8] Table 6 summarizes CRL discharges by the steam electric power plants included in EPA's costs and loadings analyses.

Table 6. CRL Wastewater Discharges for the Steam Electric Power Plants

CRL Wastewater Discharge Flow Rate					
Number of Plants	Number of EGUs	Total Daily Discharge Flow Rate (MGD)	EGU Average Daily Discharge Flow Rate (MGD per EGU)	Total Annual Discharge Flow Rate (MGY)	EGU Annual Discharge Flow Rate (MGY per EGU)
68	168	4.79	0.028	1,750	10.4

MGD = million gallons per day.

MGY = million gallons per year.

EPA also notes that unlined landfills and surface impoundments potentially discharge CRL through groundwater before entering surface water. As stated in the preamble, EPA is not addressing the definition of any terms in the CWA (such as "point source" or "discharge of a pollutant") that govern when a discharge is subject to NPDES permitting requirements or when a discharge to waters of the U.S. through groundwater is a functional equivalent of a discharge through this proposed action. Those issues are outside the scope of this rulemaking. EPA proposes that any discharge through groundwater that is the functional equivalent of a direct discharge under the Maui decision would be subject to the same BAT limitations as discharges that occur at the end of pipe. To evaluate the potential costs and loads of such discharges, EPA conducted a sensitivity analysis documented in its memorandum *Evaluation of Potential CRL in Groundwater* (U.S. EPA, 2023a).

[8] If a plant in the CRL population converted to a different fossil fuel source (*e.g.,* gas-fired), the 2023 proposal still applies and it remains in the CRL population.

3.2.4 Legacy Wastewater

The definition of legacy wastewater provided in the 2015 rule preamble and wording of limitation applicability in the actual regulation resulted in two distinct types of legacy water being captured at steam electric power plants described below. Discharges of legacy wastewater include FGD wastewater, BA transport water, fly ash transport water, CRL, gasification wastewater or flue gas mercury control (FGMC) wastewater generated before the "as soon as possible" date that more stringent effluent limitations from the 2015 or 2020 rules would apply.

The first category of legacy wastewater is wastewater that is continuously or intermittently generated and discharged to a pond after the issuance of the first permit implementing the 2015 or 2020 rule but before the compliance date specified in the permit (the "as soon as possible" date required by the rule). Discharges of this type of legacy wastewater may occur through either an intermediary structure (e.g., a tank or surface impoundment) or directly into a surface waterbody. The state permitting authority is authorized by section 423.11(t) of the regulation to determine the date that is "as soon as possible" for which these limitations can be complied with.

The second category of legacy wastewater is wastewater accumulated over years in a surface impoundment (i.e., a natural topographic depression, man-made excavation, or diked area, which is designed to hold an accumulation of coal combustion residuals and liquids, and the unit treats, stores, or disposes of coal combustion residuals)[9] that is later drained during the closure of that surface impoundment. This type of legacy wastewater consists of surficial water located above the CCR solids (i.e., "surface impoundment decant wastewater") and pore water in the saturated CCR layer (i.e., referred to as "surface impoundment dewatering wastewater"). EPA also notes that there will be an interstitial zone within these impoundments, where some disturbance of CCR solids may create sufficient mixing and present similarly elevated pollutant concentrations as SI dewatering wastewater. While wastewater in this interstitial zone is not pore water, it should be similarly situated with the pore water layer from a regulatory perspective.

EPA used the list of CCR management units to identify the population of steam electric power plants and EGUs that discharge legacy wastewater either directly into a surface waterbody or through an intermediate structure that will remain open under the CCR rule, and the population or the steam electric power plants and EGUs with surface impoundments containing legacy wastewater to be drained during a closure stage. EPA estimates that surface impoundments remaining open discharge an average of 675,000 GPD. See the *Legacy Wastewater at CCR Surface Impoundments* memorandum (U.S., EPA, 2022; U.S. EPA, 2023b) for details on the estimated volume and cost calculations. Table 7 summarizes discharges of these types of legacy wastewater by the steam electric power generating industry.

Table 7. Estimate of Total Volume of Wastewater in Surface Impoundments Identified as "In Closure"

Category	Total Number of Impoundments	Total Estimated Volume of Decant Wastewater (million gallons)	Total Estimated Volume of Dewatering Wastewater (million gallons)	Total Estimated Volume of Wastewater (million gallons)
Surface impoundments in closure process	116	19,900	35,700	56,700

Source: EPA, 2023b.

[9] EPA has always sought to harmonize the CCR rule and this ELG. Therefore, this definition was taken from 40 CFR 257.53 to match the definition under the CCR rule.

3.3 Other Regulations on the Steam Electric Power Generating Industry

The Agency recognizes that effluent guidelines on steam electric power plants do not exist in isolation—other EPA regulations set requirements for control of pollution emissions, discharges, and other releases from steam electric power plants. For the 2020 rule, EPA assessed and incorporated impacts from the CCR rule into the supporting analyses.

EPA continues to account for industry profile changes associated with the CCR rule. EPA coordinated the requirements of the CCR rule and the 2015 rule to mitigate potential impacts from the overlapping regulatory requirements and to facilitate implementation of engineering, financial, and permitting activities. Based on the CCR rule requirements established in 2015, EPA expected plants might alter how they operate their CCR surface impoundments, such as:

- Close the CCR-noncompliant disposal surface impoundment and open a new CCR-compliant disposal surface impoundment in its place.
- Convert the CCR-noncompliant disposal surface impoundment to a new storage impoundment.
- Close the CCR-noncompliant disposal surface impoundment and convert to dry handling operations.
- Make no changes to the operation of the CCR-compliant disposal surface impoundment.

As discussed in Section 1.3, EPA finalized the CCR Part A rule on July 29, 2020, setting a deadline of April 11, 2021, for all unlined surface impoundments and those surface impoundments that failed the location restriction for placement above the uppermost aquifer to stop receiving waste and begin closure. For the 2020 rule, EPA developed a methodology for using CCR surface impoundment liner data to estimate operational changes at each coal-fired power plant under the CCR Part A rule. As described in Section 3.3 of the 2020 rule, plants with unlined or clay-lined CCR surface impoundments are required to change operation or install a new CCR-compliant impoundment. EPA incorporated the CCR outputs into the 2020 rule (*i.e.,* baseline) engineering costs and loadings analyses in one of the following ways:

- Where all active CCR surface impoundments are unlined or clay-lined, EPA predicted that a plant would install tank-based FGD wastewater treatment or tank-based BA handling under the CCR Part A rule.[10]
- For plants with at least one CCR surface impoundment not affected by the CCR Part A rule (*i.e.,* not identified as unlined or clay-lined,[11] or where no data were available in the Office of Resource Conservation and Recovery data set), EPA conservatively assumed the CCR Part A rule would have little to no impact on a plant's existing FGD wastewater treatment or BA handling systems; thus, for these plants, the estimated compliance cost and pollutant loadings remain unchanged for the 2023 proposed rule.

For the proposed rule, EPA determined that 50 plants within the BA engineering costs and loadings analyses likely made changes to BA handling operations under the CCR Part A rule.[12] EPA does not

[10] For plants with at least one surface impoundment in the Office of Resource Conservation and Recovery data set, EPA assumed the listed CCR surface impoundment(s) represent all impoundments receiving FGD wastewater and/or BA transport water at the plant.

[11] The Office of Resource Conservation and Recovery data set includes 34 active CCR surface impoundments without liner designations. For these CCR surface impoundments, EPA did not assume they were unlined or clay-lined; therefore, EPA may be underestimating the number of plants that will install tank-based FGD wastewater treatment or BA handling in response to the CCR Part A rule.

[12] Any plant that installs a remote MDS to comply with the CCR Part A rule may incur costs to install a reverse osmosis system that will treat a slipstream of the recirculating BA transport water to remove dissolved solids and facilitate long-term operation of the system as a closed loop to comply with the BA zero discharge requirements of the 2015 rule. There are approaches other than reverse osmosis to remove dissolved solids from the BA system,

estimate any impacts on FGD operations as part of the proposed rule. Section 5 and Section 6 describe how EPA accounted for CCR Part A rule impacts in estimating compliance costs, pollutant loadings, and pollutant removals for the proposed rule.

such as using the transport water as makeup water for the FGD system. Dissolved solids will also be removed from the system along with the dredged BA. As appropriate, EPA will update the compliance cost estimates for these plants in future analyses.

4. 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, bottom ash (BA) transport water, leachate collected from landfills and impoundments containing combustion residuals, and legacy wastewater. This section focuses on only those technologies and practices considered as potential technology options for this 2023 proposed rule: it is not a comprehensive listing of all technologies available for treatment and management of FGD wastewater, BA transport water, leachate, or legacy wastewater. For EPA's comprehensive evaluation of available technologies and practices for the 2015 rule and 2020 reconsideration, see the 2015 Technical Development Documents (TDD) and the 2020 Supplemental TDD. Also see the *Technologies for the Treatment of Flue Gas Desulfurization Wastewater, Coal Combustion Residual Leachate, and Pond Dewatering* memorandum (U.S. EPA, 2023e) for details on other types of treatment technologies available.

This section discusses the following:

- FGD wastewater treatment technologies (Section 4.1).
- BA handling systems and transport water management and treatment technologies (Section 4.2).
- Combustion residual leachate (CRL) treatment technologies and management practices (Section 4.3).
- Legacy wastewater treatment technologies (Section 4.4).

4.1 FGD Wastewater Treatment Technologies

For the 2023 proposed rule, EPA considered treatment technologies identified as part of the 2015 and 2020 rulemakings for those plants that are still operating and discharging FGD wastewater. These technologies include low residence time reduction (LRTR) biological treatment and membrane filtration. EPA also evaluated other treatment technologies capable of achieving zero discharge of FGD wastewater including spray evaporation, other types of thermal treatment, and encapsulation.

4.1.1 LRTR Biological Treatment

Several types of biological treatment systems are used to treat FGD wastewater, including:

- Anoxic/anaerobic biological treatment systems, designed to remove selenium and other pollutants.
- Sequencing batch reactors, designed to remove nitrates and ammonia.
- Aerobic bioreactors for reducing biochemical oxygen demand (BOD).

These biological treatment processes are typically operated downstream of a chemical precipitation system or a solids removal system (*e.g.,* clarifier or surface impoundment).

The anoxic/anaerobic biological technology is designed to remove selenium, nitrate-nitrite, mercury, and other pollutants. This process uses an anoxic/anaerobic fixed-film bioreactor that consists of an activated carbon bed or other permanent porous substrate that is inoculated with naturally occurring, beneficial microorganisms. The microorganisms grow within the substrate, 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. The microorganisms reduce the selenate and selenite to elemental selenium, which forms nanospheres that adhere to the cell walls of the microorganisms. The technology can also remove other metals, including arsenic, cadmium, nickel, and mercury, by forming metal sulfides (Pickett, 2006).

As defined in the 2020 reconsideration, an LRTR biological treatment system consists of chemical precipitation[13] followed by an anoxic/anaerobic fixed-film bioreactor. In the years since it first identified anoxic/anaerobic biological technology in the 2015 rule, EPA identified different systems with varying hydraulic residence times (HRT) in the bioreactor. During the development of the 2020 reconsideration, EPA differentiated between high residence time reduction (HRTR) systems (which typically operate with HRT in the bioreactor between 10 and 16 hours) and LRTR systems (with HRT between 1 to 4 hours). Power companies and technology vendors have worked to develop processes that target removals of the same pollutants in a smaller system with a lower HRT in the bioreactor. These LRTR technologies use similar treatment mechanisms as HRTR to remove selenium, nitrate, nitrite, and other pollutants in less time.

One LRTR technology includes a chemical precipitation system followed by an anoxic, upflow bioreactor followed by a second stage downflow biofilter. The shorter HRT of this system allows for use of smaller bioreactors and other equipment, resulting in a treatment system that is physically much smaller than the HRTR system. Data provided by the power industry and an independent research organization show that LRTR's performance is comparable to HRTR's. Much of the LRTR bioreactor and related equipment is fabricated off site as modular components. Modular, prefabricated, skid-mounted components, coupled with smaller physical size, result in lower installation costs and shorter installation times than for HRTR systems, which are usually constructed on site. At least four plants have installed full-scale LRTR systems and are using them to treat FGD wastewater, and this technology has been pilot tested using FGD wastewater at more than a dozen steam electric power plants since 2012.

Another LRTR technology, fluidized bed reactors (FBRs), has been used to treat selenium in mining wastewaters; it is now being tested on FGD wastewater. The FBR system is also an anoxic/anaerobic fixed-film bioreactor design. It relies on an attached growth process, in which microbes grow on a granular activated carbon medium that is fluidized by the upflow of FGD wastewater through the suspended carbon medium. EPA identified 12 pilot studies of the FBR technology for selenium removal in mining, refining/petrochemical, and steam electric power generating industries. For the steam electric power generating industry, EPA identified three pilots involving FGD wastewater.

4.1.2 Membrane Filtration

Membrane filtration systems are specifically designed to treat wastestreams high in total dissolved solids (TDS) and total suspended solids (TSS) using thin semi-permeable filters or film membranes. Membrane filtration is used for the removal of dissolved materials from industrial wastewater and consists of one or more of the following: microfiltration, ultrafiltration, nanofiltration, reverse osmosis (RO), forward osmosis (FO), and electrodialysis reversal (EDR) membrane systems. As part of the 2020 reconsideration, EPA identified several membrane filtration technologies being studied for use with FGD wastewater, including nanofiltration membranes, RO, and FO. The membrane pore size determines the particle size that can pass through the membrane, with RO membranes being the most restrictive and microfiltration being the least restrictive. Most membrane filtration systems use pumps to apply pressure to the solution from one side of the semi-permeable membrane to force wastewater through the membrane, leaving behind dissolved solids retained ("rejected") by the membrane and a portion of the water. The rate at which water passes through the membrane depends on the operating pressure, concentration of dissolved materials, and temperature, as well as the permeability of the membrane.

Membrane systems separate feed wastewater into two product streams: a permeate stream, which is the "clean" water that has passed through the membrane, and the concentrate stream, which is the water (or brine) rejected by the membrane. The percentage of membrane system feed that emerges from the system as permeate is known as the water recovery. Depending on wastewater characteristics, membrane systems may require pretreatment to prevent scaling and fouling by removing excess TSS,

[13] Consistent with both the 2015 and 2020 reconsideration rules, chemical precipitation includes hydroxide precipitation, organosulfide precipitation, and iron coprecipitation to treat FGD wastewater.

calcium, magnesium, sulfate, or organics. Fouling occurs when either dissolved or suspended solids deposit onto a membrane surface or a microbial biofilm grows on the membrane surface and degrades its overall performance. To reduce fouling, membrane filtration systems have been designed with vortex generating blades or vibratory movement. Other systems may use a microfiltration (or ultrafiltration/nanofiltration) or chemical precipitation pretreatment step that targets scale-forming ions where FGD wastewater characteristics indicate potential fouling.

FO uses a semi-permeable membrane and differences in osmotic pressures to achieve separation. FO systems use a draw solution at a higher concentration than the feed (*e.g.,* FGD wastewater) to induce a net flow of water through the membrane. This results in diluting the draw solution and concentrating the feed stream. This technology is different from RO, which uses hydraulic pressure to drive separation. FO technology is typically better suited for high-fouling streams than traditional RO because external pumps are not needed to drive treatment.

EDR uses a semi-permeable membrane and differences in electrical charges to achieve separation of specific anions and cations. The first-of-its-kind domestic pilot of an electrodialysis reversal (EDR) pilot plant for FGD wastewater indicates that treatment with membrane filtration has continued to advance and become more available. This pilot is detailed in the 2020 EPRI report *FGD Wastewater Treatment Testing Using a Saltworks Flex EDR Selective (Electrodialysis Reversal System) Technology*, which found that "[t]he Flex EDR Selective pilot plant reliably operated for 61 days, 24/7, including weekends and unattended overnights." Other key findings included an average 93 percent water recovery, 98 percent uptime of continuous operations (over 1,440 hours), selective removal of chloride, the elimination of the need for soda ash softening, "demonstrated versatility to treat wastewater of different concentrations and water chemistries with the same treatment plant," and the potential for cost savings when compared to comparable treatment systems (EPRI, 2020).

While MF, UF, and/or NF may provide sufficient pretreatment for membrane filtration systems, incorporating chemical precipitation pretreatment can improve the efficiency of the membrane system and may help lower the capital and operation and maintenance costs. Many of the systems piloted for FGD wastewater have included some type of pretreatment (e.g., surface impoundment, chemical precipitation, microfiltration) to reduce TSS and/or soften the wastewater before it enters the membrane system. Membrane systems can be configured with polishing RO systems (*e.g.,* multi-stage RO systems) to further remove pollutants from the permeate. As well, membrane systems can be used in combination with other technologies (*e.g.,* thermal evaporation) to treat FGD wastewater or achieve zero discharge.

Permeate streams from these systems can be reused within the plant or discharged, while concentrate streams (*i.e.,* concentrated brine) would be disposed of in a landfill using encapsulation (see Section 4.1.5); in a commercial injection well; or through another process, such as thermal system treatment (see Sections 4.1.3 and 4.1.4).

EPA identified three full-scale domestic installations of membrane technologies and installations in South Africa and South America for treating wastewater in the mining industry, five domestic pilot studies in the petroleum refining and agriculture industries, and installations in Mexico and China for treating municipal landfill leachate. EPA further identified four full-scale installations of membrane filtration in the coal-to-chemical industry in China and the textile industry in India.[14] In the steam electric industry, EPA identified 17 pilot-scale studies of nanofiltration and RO used for FGD wastewater treatment world-wide (U.S. EPA,

[14] EPA has limited data on the performance and configuration of the two full-scale membrane systems treating mining wastewater and the pilot-scale systems in other industries (Wolkersdorfer, 2015; U.S. EPA, 2014; CH2M Hill, 2010; ERG, 2019; ERG, 2020). These systems may include a variety of membrane systems including nanofiltration, microfiltration, and RO systems.

2023e).[15] Some of the full-scale systems employ pretreatment before a combination of RO and FO. Others operate pretreatment followed by nanofiltration and RO. At least one plant uses thermal treatment to produce a crystallized salt from the concentrate stream, which is sold for industrial use. EPA is also aware of one U.S. facility that is conducting a long-term pilot to test a membrane filtration system for treating FGD wastewater (U.S. EPA, 2023l).

See the *Technologies for the Treatment of Flue Gas Desulfurization Wastewater, Coal Combustion Residual Leachate, and Pond Dewatering* memorandum (U.S. EPA, 2023e) for more information on pilot testing of membrane filtration technologies.

4.1.3 Spray Evaporation

Spray evaporation technologies, which include spray dryers and other similar proprietary variations, are an example of a thermal technology that is being applied to FGD wastewater treatment. Spray dryer systems evaporate wastewater by spraying fine misted wastewater into hot gasses. The hot gases allow the wastewater to evaporate before contacting the walls of the evaporation vessel, which allows spray evaporation systems to remove TDS, TSS, or scale-forming pollutants.

For FGD application, a slipstream of hot flue gas from upstream of the air heater can be used to evaporate FGD wastewater in a vessel. The FGD solids are carried along with the flue gas slipstream, which is recombined with the main flue gas stream. All solids are then removed with the fly ash by the main particulate control equipment (*e.g.,* electrostatic precipitator or fabric filter) and disposed of in a landfill. In cases where fly ash is marketable, and contamination is a concern, a separate particulate control system can be operated on the flue gas slipstream to capture FGD solids alone.

Spray evaporation systems can be used in combination with other volume reduction technologies, such as membranes, to maximize the efficiency of each process. For instance, RO systems can be installed upstream of spray evaporation technologies to reduce influent flows. Concentrate from the RO system can be processed through the spray evaporation system to achieve zero discharge. To achieve zero discharge, permeate from the RO system needs to be recirculated back into plant operation as process wastewater. Another method for reducing the volume of FGD wastewater influent to a spray evaporation system may involve reconfiguring process flow to exclude non-FGD wastewater from the treatment system (if wastewater is diluted by utility water streams prior to treatment).

EPA identified a vendor that has developed a proprietary technology that combines concepts of a brine concentrator and spray dryer to achieve zero discharge. The system, referred to as an adiabatic evaporator, injects wastewater into a hot feed gas stream to form water vapor and concentrated wastewater. The air-water mixture is separated in an entrainment separator. Water vapor is exhausted, and the concentrated wastewater is sent to a solid-liquid separator. The separated wastewater is recycled and sent back through the system, while the solids can be landfilled. An alternative configuration would be to encapsulate the separated wastewater, by mixing it with fly ash, and then landfilling. Pretreatment of FGD wastewater is not required, but—for situations where TSS exceeds 5 percent—it maybe be cost-effective to operate a clarifier upstream of the evaporator to decrease solids. The vendor operated a full-scale system at a coal-fired steam electric power plant for three years. FGD wastewater was pretreated using a clarifier, then sent to the adiabatic evaporator, where 100 percent of the FGD wastewater was evaporated and solids deposited in a landfill. Because propane was used as the heat source, operation and maintenance costs proved to be too high, and the system was replaced.

[15] EPA has limited details on these full-scale membrane systems. Some references include only plant name or location. For this reason, some references may be describing the same installation, and EPA does not have enough information to determine where this may be the case.

EPA identified two domestic installations of spray evaporation technologies treating FGD wastewater, including one installation at the Boswell Energy Center in Minnesota (U.S. EPA, 2023e). EPA also identified nine installations of spray evaporation systems treating FGD wastewater in Asia (U.S. EPA, 2023e).

See the *Technologies for the Treatment of Flue Gas Desulfurization Wastewater, Coal Combustion Residual Leachate, and Pond Dewatering* memorandum (U.S. EPA, 2023e) for more information on pilot testing of membrane filtration technologies.

4.1.4 Other Thermal Treatment Options

Thermal technologies use heat to evaporate water and concentrate solids and other contaminants. Some of these systems can be operated to achieve full evaporation of all liquid, resulting in only a solid product, or achieve partial evaporation of liquid. These thermal technologies can also be used in combination with other technologies to treat FGD wastewater or achieve zero discharge.

One type of thermal treatment uses brine concentrators followed by crystallizers; this generates a distillate stream and solid byproduct that can be disposed of in a landfill. As described in the 2015 and 2020 TDDs, four U.S. plants have installed brine concentrator systems for FGD treatment and at least four coal-fired power plants in Italy also operate this type of system for FGD wastewater (U.S. EPA, 2015a). EPA identified coal-fired steam electric power plants in China that have installed membrane treatment, followed by brine concentrators and crystallizers to treat FGD wastewater. Brine concentration followed by crystallization was evaluated as part of the 2015 rule as a possible treatment technology for the industry; see Section 7.1.4 of the 2015 TDD for a detailed description of this treatment configuration (U.S. EPA, 2015a).

EPA identified one vendor that has developed a modular brine concentration technology to heat FGD wastewater and facilitate evaporation. As the wastewater boils, steam is collected, compressed, and directed into a proprietary technology that allows the thermal energy to transfer from the steam to the concentrated wastewater stream, causing it to become superheated. As water evaporates from the superheated wastewater, the steam is collected and condensed. This distillate stream can be reused in the plant as cooling tower make-up water or within the FGD scrubber. The concentrated wastewater, referred to as brine, is discharged from the system once it reaches a set TDS concentration (not to exceed 200,000 parts per million). This brine stream is treated through hydrocyclones to remove suspended solids. The resulting liquid can be encapsulated and landfilled. Pretreatment of FGD wastewater is only required when TSS concentrations exceed 30 parts per million. Chemicals are added to maintain pH and inhibit crystal and scale formation. This technology has been pilot tested at four coal-fired power plants between 2015 and 2017.

4.1.5 Encapsulation

Encapsulation is a technology that can be used to eliminate FGD wastewater discharge. It uses chemical reactions and/or absorption processes to bond materials together so that wastewater is incorporated into the solid material. This process is also referred to as solidification. This technology has been used by plants operating inhibited oxidation scrubber systems, where byproducts from the scrubber are mixed with fly ash and lime to produce a non-hazardous landfillable material. This same approach has been tested with pretreated FGD wastewater by mixing concentrated FGD wastewater with combinations of fly ash, hydrated lime, sand, and/or Portland cement to encapsulate contaminants. Tests of these materials have confirmed that the solids generated meet solid waste leaching requirements, toxicity characteristic leaching procedure (TCLP), and other local landfill regulations (Pastore and Martin, 2017; Martin, 2019).

Encapsulation can be used alone or in combination with other treatment technologies. For instance, it can be incorporated on reduced volumes of the concentrated stream downstream of a membrane and/or thermal system. Additionally, as described in Section 4.1.3, encapsulation can be implemented downstream of spray evaporation technologies that achieve only partial evaporation and produce concentrated wastewater streams.

4.2 BA Handling Systems and Transport Water Management and Treatment Technologies

EPA reviewed BA handling systems—operated at coal-fired steam electric power plants or marketed by BA handling vendors—that are designed to minimize or eliminate the discharge of BA transport water. Many plants have installed or are installing BA handling systems that minimize or eliminate the discharge of BA transport water. The BA handling technologies evaluated by EPA and described in this section include mechanical drag systems, remote mechanical drag systems, compact submerged conveyors (CSCs), and mobile mechanical drag systems.

As part of previous rulemaking efforts in 2015 and 2020, EPA also evaluated types of dry ash handling systems: dry mechanical conveyors and pneumatic systems (i.e., dry vacuum or pressure systems). See the 2015 TDD and 2020 Supplemental TDD (U.S. EPA, 2015a; U.S. EPA 2020).

4.2.1 Mechanical Drag System

A mechanical drag system collects BA from the bottom of the EGU through a transition chute and sends it into a water-filled trough. The water bath in the trough quenches the hot BA as it falls from the EGU and seals the EGU gases. The drag system uses a parallel pair of chains attached by crossbars at regular intervals. In a continuous loop, the chains move along the bottom of the water bath, dragging the BA toward the far end of the bath. The chains then move up an incline, dewatering the BA by gravity and draining the water back to the trough. Because the BA falls directly into the water bath from the bottom of the EGU and the drag chain moves constantly on a loop, BA removal is continuous. The dewatered BA is often conveyed to a nearby collection area, such as a small bunker outside the EGU building, from which it is loaded onto trucks and either sold or transported to a landfill. See Section 7.3.3 of the 2015 TDD for more specific system details (U.S. EPA, 2015a).

The mechanical drag system does generate some wastewater (*i.e.,* residual water that collects in the storage area as the BA continues to dewater). This wastewater is either recycled back to the quench water bath or directed to the low volume waste system. This wastewater is not BA transport water because the transport mechanism is the drag chain, not the water (see 40 CFR 423.11(p)).[16]

This system may not be suitable for all EGU configurations and may be difficult to install if there is limited space below the EGU.[17] These systems cannot combine and collect BA from multiple EGUs, and most installations require a straight exit from the EGU to the outside of the building. In addition, these systems may be susceptible to maintenance outages due to BA fragments falling directly onto the drag chain.

4.2.2 Remote Mechanical Drag System

Remote mechanical drag systems collect BA using the same operations and equipment as wet-sluicing systems at the bottom of the EGU. However, instead of sluicing the BA directly to an impoundment, the plant pumps the BA transport water to a remote mechanical drag system. This type of system has the same configuration as a mechanical drag system, but with additional dewatering equipment in the trough to enable recycling BA transport water back to the system. Also, it does not operate under the EGU, but rather in an open space on the plant property. See Section 7.3.4 in the 2015 TDD for more specific system design details (U.S. EPA, 2015a).

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[16] The mechanical drag system does not need to operate as a closed-loop system because it does not use water as the transport mechanism to remove the BA from the boiler; the conveyor is the transport mechanism. Therefore, any water leaving with the BA does not fall under the definition of "bottom ash transport water," but rather is a low volume waste.

[17] In comments on the 2013 proposed ELG, three plants reported space constraints below the boiler such that a mechanical drag system could not be installed.

Plants converting their current BA handling systems can use this system if space or other restrictions limit the changes that can be made to the bottom of the EGU. Currently, over 50 coal-fired power plants have installed, or are planning to install, remote mechanical drag systems to handle BA.

Because of the chemical properties of BA transport water, some plants may need to add flocculant or polymer to aid in the settling of fines to prevent potential plugging of the sluice pipes. Other plants may have to treat the overflow (or a slipstream of the overflow) before recycling to prevent scaling and fouling in the system. Plants that require treatment to achieve complete recycling of BA transport water could install a pH adjustment system, chemical addition, or an RO membrane (as described in EPA's cost methodology in Section 5) depending on the BA transport water characteristics and materials of construction.

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. There is also an opportunity for multiple unit synergies and redundancy with remote mechanical drag systems because they are not operating directly underneath the EGU. This system needs less maintenance than the mechanical drag system because the BA particles entering it have already been through the grinder prior to sluicing.

4.2.3 CSC

A CSC, also referred to as submerged grind conveyor, collects BA from the bottom of the EGU. A CSC uses existing equipment—BA hoppers or slag tanks, the BA gate, clinker grinders, and a transfer enclosure—to remove BA from the hopper continuously. From the bottom of the EGU, BA falls into the water impounded hopper or slag tank. It is then directed to the existing grinders to be ground into smaller pieces and is then transferred to a fully enclosed bottom carry chain and flight conveyor system. Similar to a mechanical drag system (except for the fully enclosed bottom carry design), a drag chain continuously carries and dewaters BA up an incline, away from the EGU. Because the transport mechanism is the conveyor instead of water, CSCs do not generate BA transport water.[18] The dewatered BA is transferred to one or more additional conveyors, which transports it to a BA silo or bunker where the BA is collected in a truck and transported to its final destination. CSCs use additional conveyors to avoid existing structures such as pillars and coal pulverizers while conveying BA out of the EGU house. This makes it possible to install CSCs in some plants where physical constraints prevent installation of mechanical drag systems; however, physical constraints could prevent CSC installation at other plants. CSCs can also use smaller chains and are narrower and shorter than mechanical drag systems, features that potentially allow them to fit in places with insufficient space for the larger mechanical drag system conveyors.

A CSC can be isolated from the hopper using the existing transfer enclosures to perform maintenance while the EGU remains online (made possible by the BA storage capacity of the hopper). It is also possible for some plants to install parallel conveyors for redundancy (ERG, 2020a; ERG, 2020b; ERG, 2020c; ERG, 2020d).

For plants that can repurpose their wet sluicing equipment (hoppers, slag tanks, and/or clinker grinders, etc.), the capital costs of converting to CSC systems are typically lower, and installation and outage times are shorter, than for other under-the-EGU BA handling systems. However, because a CSC serves just one EGU, the more EGUs a plant has, the less economical this technology becomes.

EPA is aware of at least five plants that have installed and are operating CSC systems in the United States. EPA understands that these facilities do not have vertical space constraints under the EGUs.

[18] Like mechanical drag systems, CSCs are considered a dry handling technology, because they do not use water as the transport mechanism.

4.2.4 Mobile Mechanical Drag System

A mobile mechanical drag system is a BA transport water dewatering unit—similar to a remote mechanical drag system—with an additional clarification system (U.S. EPA, 2022b). This technology is not intended to be set on a permanent location, which reduces capital costs associated with permanent infrastructure. Depending on the facility, a mobile mechanical drag system can either remain on a truck or be installed on facility grounds. From the mechanical drag system, BA transport water is taken to a mobile clarifier and polished to a level suitable for recirculation. This mixture is sent up an incline, dewatered, and discharged.

The mobile clarifiers are typically equipped with lamella separators, polymer addition, and mobile chemical injection systems, including coagulant (typically ferric chloride) and flocculant for solids removal and caustic and acid injection for pH control. Typically, thickened sludge from the mobile clarifier is pumped back to the mechanical drag unit, with the coarse particulates acting as ballast to assist the sludge up the ramp to the mechanical drag system. The fines from the underflow of the clarifier can be pumped to a mobile belt filter press to make filter cake.

In addition to reducing capital costs, benefits of mobile systems include reduced construction costs, a smaller footprint compared to other BA treatment options, increased flexibility, minimal invasion to the facility's existing systems, manual controls to reduce complexity of control system tie-in, and the ability to serve as a recirculation system.

Mobile mechanical drag systems may have relatively higher operation and maintenance costs: the system is often a single remote mechanical drag system and an upset condition may require the unit to be shut down, and nonpermanent infrastructure (such as flexible HDPE piping and hose connections) lacks the robust nature of carbon steel or ballast line materials.

EPA is aware of one installation of a mobile system at a plant serving two coal-fired units and a full-scale pilot demo at a facility using a mobile system combined with a hydrocyclone vibrating screen to treat dewatering impoundment water.

4.3 CRL Treatment Technologies and Management Practices

In promulgating the 2015 rule, EPA determined that CRL from landfills and impoundments includes similar types of constituents as FGD wastewater, albeit at potentially lower concentrations and smaller volumes. 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.

In support of the 2015 rule, EPA identified facilities using surface impoundments, biological treatment, and constructed wetlands to treat CRL, sometimes comingled with FGD wastewater. EPA also identified facilities using other management practices to manage leachate, including recycling the wastewater in other plant operations or for moisture conditioning of fly ash. This section describes treatment technologies EPA considered for the treatment of leachate as part of this 2023 proposal, including technologies already being used by the industry.

4.3.1 Chemical Precipitation

In a chemical precipitation wastewater treatment system, chemicals are added to the wastewater to alter the physical/chemical state of dissolved and suspended solids to help precipitate, settle, and remove them. The specific chemical(s) used depends on the type of pollutant requiring removal. Steam electric power plants using chemical precipitation systems to treat FGD wastewater may include stages of hydroxide (lime), iron, and organosulfide addition, as well as clarification stages. Plants may either add all three chemicals to a single reaction tank or add the chemicals to separate tanks. Plants operating separate tanks typically target different pH set points within each tank for optimal precipitation of certain metals. Similar strategies may be applied to treat CRL, since this wastestream includes similar constituents as FGD wastewater.

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.

Plants use iron coprecipitation to increase the removal of certain metals in a hydroxide precipitation system. Steam electric power plants typically use ferric chloride to coprecipitate additional metals and organic matter. The ferric chloride also acts as a coagulant, forming a dense floc that enhances settling of the precipitated metals in downstream clarification stages.

Organosulfide precipitation systems use organosulfide chemicals (*e.g.,* trimercapto-s-triazine [TMT], Nalmet® 1689, MetClear™, sodium sulfide) to precipitate and remove heavy metals. Plants may test several organosulfide chemicals to determine which one is most appropriate for their treatment systems. Organosulfide precipitation can also optimize removal of metals with lower solubilities, such as mercury, more effectively than hydroxide precipitation or hydroxide precipitation with iron coprecipitation. EPA sampling data show that adding organosulfide to the FGD wastewater can reduce dissolved mercury concentrations to less than 10 parts per trillion (ERG, 2012). Organosulfide precipitation is more effective than hydroxide precipitation in removing metals with low solubilities because metal sulfides have lower solubilities than metal hydroxides. Due to the relatively low costs of 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 costs.

EPA's data demonstrate that well-operated systems maintain their chemical precipitation effluent concentrations because they actively monitor target 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.

See Section 7.1.2 in the 2015 TDD for more specific chemical precipitation system design details (U.S. EPA, 2015a).

4.3.2 Biological Treatment

Some plants use the same biological wastewater treatment systems to treat both FGD wastewater and leachate, in some cases as a combined stream. Microorganisms consume biodegradable soluble organic contaminants and bind much of the less soluble fractions into floc. Pollutant concentrations may be reduced aerobically, anaerobically, and/or by using anoxic zones to remove metals and nutrients. EPA identified two facilities using fixed-film bioreactors that reduce selenium and nitrate/nitrite to treat CRL. See Section 4.1.1 for more details on the LRTR system specific to FGD wastewater treatment, which can also be used to treat leachate.

4.3.3 Membrane Filtration

See Section 4.1.2 for a description of membrane treatment technologies, which can also be used to treat leachate from landfills and impoundments containing combustion residuals.

4.3.4 Thermal Treatment Options

See Sections 4.1.3 and 4.1.4 for a description of thermal treatment technologies, including spray evaporation, that can also be used to treat leachate from landfills and impoundments containing combustion residuals. EPA's review of thermal treatment options to treat CRL show that four technology vendors are operating these systems at municipal landfills. See EPA's *Technologies for the Treatment of*

Flue Gas Desulfurization Wastewater, Coal Combustion Residual Leachate, and Pond Dewatering memorandum for more information (U.S. EPA, 2023e).

4.3.5 Management Strategies and Reuse

In promulgating the 2015 rule, EPA also identified steam electric power plants using other types of management strategies for CRL from landfills and impoundments (U.S. EPA, 2015a):

- As of 2009, 24 plants collect combustion residual landfill or impoundment leachate and use it as water for moisture conditioning dry fly ash prior to disposal or dust control around dry unloading areas and landfills.
- As of 2009, EPA identified five plants that use collected leachate from landfills or impoundments as truck wash and route it back to impoundments.
- As of 2009, approximately 40 percent of plants collect CRL from impoundments and recycle it directly back to the impoundments from which it was collected.

4.4 Legacy Wastewater Treatment Technologies and Management Practices

As described in the preamble for the proposed rule, legacy wastewater consists of the following:

- Wastewater generated between new permit issuance and the "as soon as possible" date for more stringent effluent limitations to apply that is continuously generated and discharged.
- Wastewater accumulated over years in a surface impoundment (*i.e.,* a natural topographic depression, artificial excavation, or diked area that is designed to hold an accumulation of CCR and liquids and treats, stores, or disposes of those residuals) that is later drained during the closure of that surface impoundment.

The following technologies can be applied to treat each type of legacy wastewater being captured at steam electric power plants.

4.4.1 Legacy Wastewater Discharged Directly to Surface Waterbodies or Through Intermediary Structures

Discharges of legacy wastewater generated between new permit issuance and the "as soon as possible" date for more stringent effluent limitations to apply may occur through an intermediary structure (*e.g.,* a tank or surface impoundment) or directly into a surface waterbody. EPA has determined that the following technologies, which can also treat FGD wastewater, can be applied to treat this type of legacy wastewater.

4.4.1.1 Chemical Precipitation

See Section 4.3.1 for a description of chemical precipitation technologies that can also be used to treat this type of legacy wastewater.

4.4.1.2 Biological Treatment

See Sections 4.1.1 and 4.3.2 for descriptions of biological treatment technologies that can also be used to treat this type of legacy wastewater. Furthermore, Section 7.1.3 of the 2015 TDD and Section 4.1.1 of the 2020 TDD include additional biological treatment system design details (U.S. EPA, 2015a; U.S. EPA, 2020).

4.4.1.3 Zero Valent Iron

Zero valent iron (ZVI), in combination with other systems such as chemical and physical treatment, can be used to target specific inorganics, including selenium, arsenic, nitrate, and mercury, in this type of legacy wastewater.

The technology entails mixing influent wastewater with ZVI (iron in its elemental form), which reacts with oxyanions, metal cations, and some organic molecules in wastewater. ZVI causes a reduction reaction of these pollutants, after which the pollutants are immobilized through surface adsorption onto iron oxide coated on the ZVI or generated from oxidation of elemental iron. The coated, or spent, ZVI, is separated from the wastewater with a clarifier. The quantity of ZVI required and the number of reaction vessels can be varied based on the composition and amount of wastewater being treated.

Treatment configurations may include chemical precipitation followed by ZVI treatment and may also include pretreatment to partially reduce influent nitrate concentrations. The purpose of the nitrate pretreatment is to reduce the consumption rate of the ZVI media, which reacts with both the nitrates and selenium in the wastewater.

EPA identified two full-scale installations of the ZVI technology for selenium removal in mining wastewater and seven completed pilot-scale studies of ZVI used for FGD wastewater treatment.[19,20] At least four additional pilot-scale studies for FGD wastewater treatment were in the planning stage at plants in the eastern United States, as of 2016. The data from a subset of these pilot tests indicate that the combination of chemical precipitation and ZVI technology, along with nitrate pretreatment where warranted, can produce effluent quality comparable to chemical precipitation followed by low residence time reduction (CP+LRTR), and chemical precipitation followed by high residence time reduction (CP+HRTR) technologies.

4.4.1.4 Membrane Filtration

See Section 4.1.2 for a description of membrane treatment technologies that can also be used to treat this type of legacy wastewater.

4.4.1.5 Thermal Treatment

See Sections 4.1.3 and 4.1.4 for a description of thermal treatment technologies, including spray evaporation, that can also be used to treat this type of legacy wastewater.

4.4.1.6 Encapsulation

See Section 4.1.5 for a description of encapsulation technologies that can also be used to treat this type of legacy wastewater.

4.4.1.7 Other Emerging Technologies

See Section 4.1.6 of the 2020 TDD for descriptions of emerging technologies for FGD wastewater treatment that can also be applied to treat this type of legacy wastewater (U.S. EPA, 2020). These

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[19] EPA has limited data on the performance and configuration of the two full-scale ZVI systems treating mining wastewater (Butler, 2010). At least one of the systems includes ZVI in combination with an RO membrane system to target selenium removal.

[20] In addition to the seven FGD pilots of ZVI, EPA has observed ZVI technology in treating ash transport water during impoundment dewatering at a plant. In this application, the impoundment water was first treated by RO membrane filtration, and the membrane reject stream was sent to ZVI reactors for treatment. The membrane permeate and ZVI effluent streams were both discharged by the plant to surface waters. Although this application was not treating FGD wastewater, many of the pollutants present in FGD wastewater are also present in ash impoundments, and these pollutants were effectively removed by the ZVI process (ERG, 2019a). A similar treatment train has been suggested for FGD wastewater: chemical precipitation followed by RO membrane filtration, with the membrane reject stream sent to a ZVI stage consisting of three reactors in series. As with the treatment system for the impoundment, the RO permeate and ZVI effluent would be discharged (unless the RO permeate was reused within the plant).

emerging technologies include electrodialysis reversal and RO technology, closed-loop mechanical vapor recompression, and distillation-based thermal transfer systems.

4.4.2 Legacy Wastewater Discharged from Surface Impoundments Undergoing Closure

Legacy wastewater that is accumulated over years in a surface impoundment and drained during the closure of that surface impoundment consists of surficial water located above the CCR solids (*i.e.,* “surface impoundment decant wastewater”) and pore water in the saturated CCR layer at levels beyond that needed for conditioning (*i.e.,* “surface impoundment dewatering wastewater”). EPA notes that there will be an interstitial zone within these impoundments, where some disturbance of CCR solids may create enough mixing between these zones for pollutant concentrations to be elevated in impoundment decant wastewater.

EPA recognizes that the wastewater characteristics of decant and dewatering water may differ within a CCR impoundment. Therefore, treatment requirements may change as closure continues. Wastewater characteristics also differ across CCR impoundments due to fuel type burned, duration of impoundment operation, and ash type. The treatment technologies listed in Section 4.4.1 are applicable to the decant and dewatering wastewaters; however, treatment may require a combination of technologies (*e.g.,* chemical precipitation and membrane filtration).

For example, the state of North Carolina issued several permits to Duke Energy that applied water quality-based effluent limitations on several pollutants once the surface impoundment reached lower water levels. These pollutants differ for each permit, but the permits generally have led to the inclusion of physical settling, chemical precipitation, and (for at least one facility) ZVI treatment. These systems can be operated to remove TSS, metals, selenium, and nutrients from surface impoundment decant and dewatering wastewaters. See Sections 4.3.1 and 4.4.1.3 for a description of chemical precipitation and ZVI technologies. EPA also is aware of one plant that is treating legacy wastewater with spray evaporators, which are equipped to treat the variable characteristics often encountered when dewatering impoundments and treating legacy wastewater.

Solids dewatering can also occur when CCR materials are dredged from the impoundment as part of clean closure. It typically involves mobile dewatering systems that are self-contained on a trailer and can thus be easily moved on and off site. Decant wastewater from a holding area (*e.g.,* pit, impoundment, collection tank) is pumped through a filter press to generate a filter cake and water stream. A shaker screen can be added to remove larger particles prior to the filter press. Furthermore, the filter press can be equipped with automated plate shifters to allow solids to drop from the end of the trailer directly into a loader or truck. The resulting wastewater stream may be further treated to meet any discharge requirements.

5. Engineering Costs

For the proposed rule, EPA estimated compliance costs for flue gas desulfurization (FGD) wastewater, bottom ash (BA) transport water, and combustion residual leachate (CRL) from landfills.[21] These estimates further develop the estimated costs from the 2015 and 2020 rules. Section 9 of the 2015 rule TDD presents EPA's methodology for estimating compliance costs for FGD wastewater, BA transport water, and CRL from landfills. Section 5 of the 2020 rule TDD describes EPA's cost estimates for FGD wastewater and BA transport water. Here, EPA is presenting cost estimates for baseline compliance, post-compliance, and incremental costs defined as follows:

- *Baseline compliance costs.* The costs for plants to comply with effluent limitations based on the technologies considered in the 2023 proposed rule technology options. EPA based its analysis on a modeled baseline that reflects the full implementation of the 2020 rule, the expected effects of announced retirements and fuel conversions, and the impacts of relevant final rules affecting the power sector. As such, the baseline appropriately includes the costs of achieving the 2020 rule limitations and standards, and the policy cases show the impacts resulting from changes to the existing 2020 limitations and standards. For more information, see the Regulatory Impact Analysis for Proposed Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (RIA, U.S. EPA, 2023f). For FGD wastewater and BA transport water, the baseline compliance costs anticipate that plants will have met the requirements of the 2020 rule; for CRL, baseline compliance costs consider current treatment in place.
- *Post-compliance costs*. The costs for plants to comply with effluent limitations based on the technologies considered in the 2023 proposed rule technology options. EPA estimated post-compliance costs with the expectation that all steam electric power plants subject to the requirements of the proposed rule will install and operate wastewater treatment and pollution prevention technologies equivalent to the technology bases for the regulatory options.
- *Incremental costs*. The difference between the baseline compliance costs and 2023 proposed rule post-compliance costs for each regulatory option.

EPA's compliance cost estimates include the following components:

- *Capital costs (one-time costs).* Capital costs comprise the direct and indirect costs associated with purchasing, delivering, and installing pollution control technologies. Capital cost elements include purchased equipment and freight, equipment installation, buildings, site preparation, engineering costs, construction expenses, contractor's fees, and contingencies.
- *Annual operation and maintenance (O&M) costs (incurred every year).* Annual O&M costs comprise all costs related to operating and maintaining the pollution control technologies for a period of one year. O&M cost elements include costs associated with operating labor, maintenance labor, maintenance materials (routine replacement of equipment due to wear and tear), chemical purchases, energy requirements, residuals disposal, and compliance monitoring.
- *Other one-time or recurring costs.* In some cases, the technology options may also result in costs that recur less often than annually (*e.g.,* three-year recurring costs for equipment replacement) or one-time costs other than capital investment (*e.g.,* one-time cost to consult with an engineer).

EPA updated its industry profile as follows:

[21] Consistent with the 2015 rule, EPA assumed that plants required to treat surface impoundment leachate would decide to recycle the leachate back to the impoundment where it was generated.

- EPA began by updating its profile to reflect retirements of electric generating units (EGUs) that will occur by December 31, 2028, for the FGD wastewater and BA transport water populations. For CRL, EPA removed plants that will have retired all coal-fired EGUs by December 31, 2023.
- EPA also removed any EGUs that will have converted to a non-coal fuel source by December 31, 2028, for FGD wastewater and BA transport water populations. EPA did not remove refuels from the CRL population. These EGUs, which previously burned coal and generated coal combustion residuals (CCRs) that were disposed of in landfills, remained in the population because the corresponding power plant is still operating. Based on the applicability of 40 CFR 423, the plant and landfill leachate are still subject to the guidelines. See Section 5.3.1 for details on how EPA developed the CRL population.
- Through January 2022, EPA incorporated any notices of planned participation (NOPPs) to meet limitations for low utilization electric generating units (LUEGUs) for BA transport water into its analyses. EPA also accounted for any plants that opted into the Voluntary Incentives Program (VIP) through January 2022 for FGD wastewater.

The remainder of this section describes EPA's methodology for estimating baseline compliance costs, post-compliance costs, and incremental costs by wastestream, as well as industry-level compliance cost estimates for each of the 2023 proposed regulatory options:

- FGD wastewater (Section 5.1).
- BA transport water (Section 5.2).
- CRL (Section 5.3).

Finally, this section summarizes baseline and regulatory option costs (Section 5.4).

5.1 FGD Wastewater

For the proposed rule, EPA estimated costs for plants to install and operate two technologies: chemical precipitation followed by low residence time reduction (CP+LRTR) and membrane filtration.

For CP+LRTR, EPA included the following treatment components for FGD wastewater, consistent with the 2020 rule methodology:

- CP treatment equipment (equalization and storage tanks, pumps, reaction tanks, solids-contact clarifier, and gravity sand filter).
- CP chemical feed systems (lime, organosulfide, ferric chloride, and polymers).
- CP solids-contact clarifier to remove suspended solids.
- LRTR treatment equipment (anoxic/anaerobic bioreactor, flow control, backwash supply, storage tanks).
- LRTR chemical feed system for nutrients.
- Pretreatment system for nitrate/nitrites (for plants with nitrate/nitrite concentrations above 50 parts per million [ppm]).
- Heat exchanger.
- Ultrafilter.
- Compliance monitoring (including sample collection and analysis).
- Solids handling (sludge holding tank and filter press).
- Transportation and disposal of solids in a landfill.

For membrane filtration, EPA included the following FGD wastewater treatment components, consistent with the 2020 rule methodology:

- CP treatment equipment (equalization and storage tanks, pumps, reaction tanks, solids-contact clarifier, and gravity sand filter).
- CP chemical feed systems (lime, organosulfide, ferric chloride, and polymers).
- CP solids-contact clarifier to remove suspended solids.
- Membrane filtration treatment equipment (membrane filtration, reverse osmosis (RO), and storage tanks).
- Brine encapsulation.
- Transportation and disposal of solids in a landfill.

Section 5.1.1 describes the cost inputs and the methodology for updating the FGD wastewater flow rates from the 2020 rule. Sections 5.1.2 and 5.1.3 present EPA's methodology for estimating costs for LRTR and membrane filtration, respectively.

5.1.1 FGD Cost Calculation Inputs

To estimate plant-level baseline and post-compliance costs of implementing FGD wastewater treatment technologies, EPA developed a cost calculation database. This database combines plant-specific input values, including wastewater flow rates and existing wastewater treatment, with the relationships between costs and FGD flow rates described in Sections 5.1.2 and 5.1.3 to estimate baseline and post-compliance costs for each plant (ERG, 2023). For the proposed rule, EPA used input data compiled from the 2015 and 2020 rules, including Steam Electric Survey data, site visits, sampling episodes, and other industry-provided data, and updated these data using new information gathered from industry (see Section 2). This section describes the updates to cost inputs from the 2020 rule.

5.1.1.1 Population

EPA identified coal-fired power plants that discharge FGD wastewater to surface water or a publicly owned treatment works (POTW) and that are not expected to retire or convert fuel sources by December 31, 2028. EPA started with the population of plants from the 2020 rule and updated the population based on new publicly available data on operational changes and industry-provided data. EPA also compiled a list of the EGUs at these plants that discharge FGD wastewater, keeping in mind that some plants retire or convert individual EGUs and not the entire plant.

5.1.1.2 Flow Rate

For each plant, EPA estimated two FGD purge flow rates: the FGD purge flow rate (the typical amount of wastewater from the FGD scrubber that is sent to FGD wastewater treatment) and the FGD optimized flow rate (a reduced rate that considers a reduction in FGD wastewater purged from the system, where equipment metallurgy could accommodate increased chloride concentration in the FGD system). As in the 2020 rule, EPA used the FGD purge flow rate to calculate capital costs to ensure that the installed treatment technologies would be able to accommodate the maximum possible FGD flow. EPA also concluded that plants would optimize the FGD purge flow rate to reduce the flow that must be treated, and thereby reduce overall O&M compliance costs. As flows are recycled through the FGD system, chloride concentrations increase; therefore, when calculating an optimized flow rate, EPA considered plant-specific constraints such as maximum design chloride concentrations and operating chloride concentrations for the FGD systems.

For the proposed rule, EPA largely used plant-specific FGD wastewater flows consistent with the 2020 rule (U.S EPA, 2020). EPA identified some facilities where changes to plant operations warranted updates to FGD wastewater flow rates. At plants where some, but not all, EGUs plan to retire or convert fuels before December 31, 2028, EPA adjusted FGD wastewater flow rates (purge and optimized) to remove flow for these EGUs. Refer to the *Flue Gas Desulfurization Flow Methodology for Compliance Costs and Pollutant Loadings* memorandum for a summary of these updates (U.S. EPA, 2023g).

5.1.1.3 Baseline Treatment Technology

For this cost analysis, EPA assumed that plants subject to the FGD wastewater discharge requirements in the 2020 rule would install the treatment technology basis defined for the 2020 rule. If a plant opted into the 2020 rule VIP, then EPA assumed membrane filtration as the baseline treatment technology. For all other FGD wastewater discharges, EPA assumed CP+LRTR baseline treatment technology. Table 8 outlines the baseline scenarios for the plants included in EPA's 2023 proposal analyses and the corresponding estimated compliance costs.

Table 8. 2023 Rule Technology Bases

2023 Technology Option Evaluated	2020 Rule Subcategory [a]	2023 Baseline Treatment Technology	Estimated Incremental Capital Compliance Cost	Estimated Incremental O&M Compliance Cost
CP+LRTR	VIP	Membrane filtration	Costs are equal to zero	Costs are equal to zero
	All other FGD wastewater discharges	CP+LRTR	Costs are equal to zero	Costs for monitoring only
Membrane filtration	VIP	Membrane filtration	Costs are equal to zero	Costs are equal to zero
	All other FGD wastewater discharges	CP+LRTR	Costs for membrane filtration (no CP costs)	Costs for membrane filtration minus LRTR (no CP costs)[b]

a—EPA did not evaluate costs associated with the 2020 rule FGD high-flow subcategory because the one applicable plant is scheduled to retire its coal-fired EGUs by December 31, 2028.

b—EPA estimated O&M costs as the incremental costs between operating and maintaining an LRTR system (see Section 5.1.2) versus operating and maintaining a membrane filtration system (see Section 5.1.3). For the membrane filtration technology option, EPA assumed plants will stop operating the LRTR portion of the system but continue operating the CP portion as pretreatment for membrane filtration.

5.1.2 Cost Methodology for LRTR

As described in the RIA, EPA's baseline appropriately includes the costs of achieving the 2020 rule limitations and standards, and the policy cases show the impacts resulting from changes to the existing 2020 limitations and standards. Therefore, EPA assumed that plants have come into compliance with the 2020 rule; thus, all plants in the proposed rule analysis are assumed to have installed CP+LRTR, membrane filtration, or equivalent treatment. Since both technology bases include CP, EPA did not estimate additional compliance costs for CP treatment.

EPA updated the 2020 rule LRTR cost curves by adjusting the cost indexing values to estimate costs in 2021 dollars using data from the RSMeans Historical Cost Index (RSMeans 2018; RSMeans 2021). The 2018 cost index value was 215.8, and the 2021 cost index value was 236.7. EPA multiplied the cost curve components by the ratio of these indices (the 2021 index divided by the 2018 index equals 1.097), resulting in the equations presented below. To determine plant-specific nitrate/nitrite concentrations and consequently which LRTR cost curve to use, EPA used sampling data from the 2015 rule analytical database (ERG, 2015 and 2015a) and the Steam Electric Survey (U.S. EPA, 2015). Plants with nitrate/nitrite concentrations above 50 milligrams per liter (mg/L) in untreated FGD wastewater require nitrate/nitrite pretreatment and are considered "high nitrates."

The resulting adjusted cost curves are as follows:

$$\text{LRTR capital cost – low nitrates (2021\$)} = 5.69 \times \text{FGD flow (GPD)} + 4{,}659{,}327$$

$$\text{LRTR O\&M cost – low nitrates (2021\$/year)} = 0.806 \times \text{FGD flow (GPD)} + 358{,}299$$

$$\text{LRTR capital cost – high nitrates (2021\$)} = 6.75 \times \text{FGD flow (GPD)} + 5{,}542{,}021$$

$$\text{LRTR O\&M cost – high nitrates (2021\$/year)} = 1.2 \times \text{FGD flow (GPD)} + 378{,}901$$

In addition, as part of the 2020 and 2015 rules, EPA estimated compliance monitoring costs to account for sampling labor and materials as well as the costs associated with sample preservation, shipping, and analysis for the pollutants selected for regulation (arsenic, mercury, nitrate/nitrite, and selenium for CP+LRTR). EPA also updated the compliance monitoring cost to 2021 dollars, resulting in an amount of $82,936.

EPA estimated CP+LRTR plant-level costs as follows:

- For plants opting in to the 2020 VIP, EPA estimated zero capital and zero O&M costs.
- For all other plants with FGD discharges, EPA estimated capital costs as zero and O&M costs as compliance monitoring only ($82,936).

5.1.3 Cost Methodology for Membrane Filtration

As with the LRTR cost methodology, EPA did not estimate additional costs for CP pretreatment for the membrane filtration technology option, as plants are assumed to have come into compliance with the 2020 rule and already have this treatment in place. EPA updated the 2020 rule membrane filtration cost curves by escalating them to 2021 dollars as described in Section 5.1.2.

The resulting curves are as follows:

$$\text{membrane filtration capital cost with on-site transport/disposal (2021\$)} = \\ 43.0 \times \text{FGD flow (GPD)} + 1{,}784{,}805$$

$$\text{membrane filtration O\&M cost with on-site transport/disposal (2021\$/year)} = \\ 6.28 \times \text{FGD flow (GPD)} + 509{,}287$$

$$\text{membrane filtration capital cost with off-site transport/disposal (2021\$)} = \\ 39 \times \text{FGD flow (GPD)} + 1{,}822{,}650$$

$$\text{membrane filtration O\&M cost with off-site transport/disposal (2021\$/year)} = \\ 12.6 \times \text{FGD flow (GPD)} + 509{,}585$$

EPA estimated plant-level membrane filtration costs as follows:

- For plants opting in to the 2020 VIP, EPA estimated zero capital and zero O&M costs.
- For all other plants with FGD discharges, EPA estimated plant-specific capital and O&M costs.
  - EPA estimated capital costs for membrane filtration only, using the capital cost equations in Section 5.1.3 and FGD purge flow rate. To determine which plants have on-site landfills for CCR material, EPA used data from the Steam Electric Survey and public permit data. All other plants were assumed to dispose of solids in off-site landfills.
  - EPA estimated O&M costs as the difference in costs between LRTR and membrane filtration only. (All plants are assumed to be currently operating LRTR systems, which they will replace with membrane systems for this technology option.) To estimate this difference, EPA estimated LRTR O&M costs using equations in Section 5.1.2 and membrane O&M costs using equations in Section

5.1.3, with both using FGD optimized flows. O&M costs for the membrane filtration technology option were calculated as the difference between LRTR and membrane values.

5.2 BA Transport Water

EPA estimated BA transport water costs for wastewater treatment and pollutant prevention technologies equivalent to the technology bases defined by the proposed regulatory options. The BA transport water technology options considered as part of the proposed rule include high recycle rate (HRR) and zero liquid discharge (ZLD). For the proposed HRR option, EPA estimated costs for mechanical drag system (MDS) installations and remote MDS installations with a purge. See Section 5.2.1 for the HRR cost methodology. For the proposed ZLD option, EPA estimated costs for MDS installations and closed loop remote MDS installations. (A closed loop remote MDS installation includes an RO system to allow complete recycle, along with return pumps, pipes, and surge tank capacity.) See Section 5.2.2 for the detailed cost methodology for ZLD.

For the MDS, EPA included costs to replace the existing boiler hopper and associated equipment, and to install and operate a semi-dry silo for temporary storage of the BA.

For the remote MDS, EPA included the costs to install and operate the following, consistent with the 2020 rule methodology:

- Remote MDS (away from the boiler).
- Sump.
- Recycle pumps.
- Chemical feed system.[22]
- Semi-dry silo.

For EGUs with low utilization, EPA estimated costs to prepare and implement best management practices (BMP) plans.[23] These costs include the initial development and annual review of a BMP plan to recycle as much BA transport water as practicable, as well as the capital and O&M costs for pumps and piping associated with the recycle system.

EPA also included the capital and O&M costs of transporting and disposing of all BA in a landfill for both technology options considered.

Section 5.1.1 describes the cost inputs for the proposed rule. Sections 5.2.2 and 5.2.3 present EPA's methodology for estimating costs for HRR and ZLD, respectively.

5.2.1 BA Transport Water Cost Calculation Inputs

To estimate plant-level baseline and post-compliance costs of implementing BA transport water technologies, EPA developed a cost calculation database. This database uses plant-specific input values including BA production, current BA handling system details, and information on the use of on-site and off-site landfills in combination with relationships between costs and EGU capacity or BA generation described in Sections 5.2.2 and 5.2.3 to estimate baseline and post-compliance costs for each plant (ERG,

[22] EPA included costs for a chemical feed system to control pH of the recirculating system to prevent scaling within the system. Information in the record indicates that few, if any, plants are likely to need such systems. However, because EPA could not conclusively determine that none would, or which plants would be more likely to need chemical feed systems, EPA estimated this cost 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.

[23] Applied only to plants with EGUs with a two-year average capacity utilization of less than 10 percent, excluding plants with a generation capacity less than or equal to 50 MW.

2023a). For the proposed rule, EPA used input data compiled from 2015 and 2020 rules—including Steam Electric Survey data, site visits, sampling episodes, and other industry-provided data—and updated based on new information gathered from industry and information available from the Department of Energy and NPDES permits (see Section 2). This section describes the updates to cost inputs from the 2020 rule.

5.2.1.1 Population

EPA identified coal-fired power plants that operate wet BA handling systems and discharge BA transport water to surface water or a POTW, and that are not expected to retire or convert fuel sources by December 31, 2028. EPA started with the population of units from the 2020 rule and updated that population based on new publicly available data on operational changes and industry-provided data.

5.2.1.2 Production Data

For each applicable EGU, EPA estimated the amount of wet BA produced in tons per year (TPY), generating capacity in megawatts (MW), and net generation in megawatt-hours (MWh). EPA used BA production and capacity values reported in the Steam Electric Survey as input values for estimating compliance costs for the final rule. EPA used EGU-level net generation values reported in the 2017 and 2018 EIA data to identify low utilization EGUs.

5.2.1.3 Cost Type Flags

EPA used data from the Steam Electric Survey, site visits, public comments, and other industry sources, discussed in Section 2, to identify the types of BA handling systems currently operating at each plant. For each type of BA handling system, EPA determined the equipment or services needed to implement each technology option. EPA categorized each EGU into the following cost categories:

- Steam electric EGUs equipped with only wet BA handling systems that discharge BA transport water.
- Steam electric EGUs equipped with only wet BA handling systems that discharge BA transport water and have space constraints preventing the installation of MDSs.
- Steam electric EGUs already operating remote MDSs.
- Steam electric EGUs equipped with only wet BA handling systems that recycle all of their BA sluice, but can discharge BA transport water from emergency outfalls. EPA defined these as BA management plants.
- Steam electric EGUs operating dry BA handling systems.

5.2.1.4 Flow Rate

EPA used industry-submitted data, data from public comments, and data from the Steam Electric Survey (discussed in Section 2) to calculate BA transport water flow rates for baseline conditions and each technology option evaluated for the proposed rule.

EPA defined the baseline as plants complying with the 2020 rule. For baseline conditions, EPA estimated BA transport water flow rates for the HRR technology option, which would allow plants to discharge a portion of their BA transport water. EPA estimated BA transport water flow rates for three compliance approaches available to most plants:

- *Zero flow.* For a plant using a dry BA handling system to comply with baseline or a technology option (*e.g.,* under-boiler mechanical drag system), the discharge flow rate equals zero.
- *Purge flow*. For each plant using a recirculating BA handling system to comply with baseline or a technology option (e.g., remote MDS operated with a purge instead of completely closed-loop), EPA estimated a BA transport water purge flow rate. EPA calculated BA transport water purge flow rates for remote MDS installations based on a relationship between the plant's generating capacity and the volume of the total wetted, active components of the remote MDS, consistent with the methodology

described in Section 5.2.3. Where EPA identified EGUs retiring or converting fuel sources, EPA adjusted the plant generating capacity to account for changes.

- *Sluice flow.* For plants using a surface impoundment plus BMP plan to comply with baseline (per the 2020 rule), EPA identified one plant in the low utilization subcategory for which the discharge flow rate would equal the plant's BA sluice flow.

5.2.1.5 Baseline Treatment Technology

For this cost analysis, EPA assumed that plants subject to the BA transport water discharge requirements in the 2020 rule would install the treatment technology basis defined for the 2020 rule and any applicable subcategories (*i.e.,* baseline). For baseline and regulatory options costs, EPA accounted for updates to the industry profile including retirements and NOPPs through January 2022. Table 9 outlines the baseline scenarios for the plants included in EPA's 2023 proposal analyses and the corresponding estimated compliance costs. Baseline assumptions for BA transport water account for the CCR Part A rule (40 CFR 257).

Table 9. 2023 Rule Technology Bases

2023 Technology Option Evaluated	2020 Rule Subcategory	2023 Baseline Treatment Technology	Estimated Incremental Capital Compliance Cost	Estimated Incremental O&M Compliance Cost
HRR	All other BA discharges	Dry handling or HRR system	Costs are equal to zero	Costs are equal to zero
	Low utilization boilers: all EGUs have 24-month average utilization < 10%	Surface impoundment + BMP plan	Costs for MDS/remote MDS with purge	Costs for MDS/remote MDS with purge
ZLD	All other BA discharges	Dry handling or HRR system	Costs for RO	Costs for RO
	Low utilization boilers: All EGUs have 24-month average utilization < 10%	Surface impoundment + BMP plan	Costs for MDS/remote MDS with purge	Costs for MDS/remote MDS with purge

EPA identified eight EGUs from five plants as BA management. EPA assumed, based on information from the Steam Electric Survey, that these plants have retained the capability to discharge BA transport water only from emergency outfalls but generally operate as closed-loop systems.

5.2.2 Cost Methodology for HRR

As described in the RIA, EPA's baseline appropriately includes the costs of achieving the 2020 rule limitations and standards, and the policy cases show the impacts resulting from changes to the existing 2020 limitations and standards. Therefore, EPA assumed that plants in compliance with the 2020 rule will have installed MDS or remote MDS and therefore are estimated to incur zero costs to comply with proposed HRR technology options. EPA compared the costs of installing an MDS and a remote MDS for each plant and chose the least cost option as the technology basis for HRR. EPA calculated plant-specific MDS and remote MDS compliance costs for the 2023 proposal EGU-level BA generation and/or EGU capacity.[24] EPA updated the 2020 rule cost curves by escalating them to 2021 dollars as described in Section 5.1.2. The recurring expenses for MDS and rMDS installations account for the cost for chain replacement that may be needed every three and five years, respectively. To estimate plant-level costs, EPA first calculated the capital and O&M costs at the EGU-level, using the following curves:

$$\text{EGU MDS capital cost (2021\$)} = (39{,}288 \times [\text{MW}]) + 5{,}499{,}451$$

$$\text{MDS annual O\&M cost (2021\$/year)} = (18.823 \times [\text{TPY}]) + 575{,}891$$

$$\text{MDS three-year recurring O\&M cost (2021\$)} = \$225{,}767$$

$$\text{EGU remote MDS capital cost (2021\$)} = [(28{,}787 \times [\text{MW}]) + 3{,}784{,}115] + \text{building cost}$$

$$\text{remote MDS annual O\&M cost (2021\$/year)} = (19.385 \times [\text{TPY}]) + 855{,}210$$

$$\text{remote MDS five-year recurring O\&M cost (2021\$)} = \$225{,}767$$

EPA added surface impoundment cost savings to the MDS and remote MDS capital and O&M EGU-level costs. Consistent with the 2020 rule methodology, EPA used Steam Electric Survey data to identify plants that have at least one impoundment containing BA transport water and not designated as retired or planned. Where EPA had data indicating plants had installed dry or HRR BA handling systems since the 2020 rule, EPA assumed these plants would opt to no longer operate impoundments for BA handling, resulting in surface impoundment cost savings. EPA also assumed that plants whose impoundments are expected to close due to CCR Part A rule requirements would no longer use impoundments for BA handling, resulting in surface impoundment cost savings. EPA estimated plant-level cost savings for no-longer-operating impoundments based on the total amount of BA solids currently handled wet at the plant. EPA updated the 2020 rule BA impoundment O&M cost savings by escalating them to 2021 dollars as described in Section 5.1.2.

$$\text{total BA impoundment O\&M cost savings (2021\$/year)} = \text{(BA impoundment operating cost savings + BA earthmoving cost savings)}$$

Where:

BA impoundment operating cost savings	=	Total impoundment operating cost savings.
BA earthmoving cost savings	=	O&M cost associated with the earthmoving equipment savings.

EPA estimated the BA impoundment operating cost savings by first calculating the plant MW factor and the plant-specific unitized cost.

$$\text{plant MW factor} = 7.569 \times (\text{plant size})^{-0.32}$$

Where:

Plant size	=	Plant size in MW (the plant nameplate capacity for only those EGUs in the BA costed population).

[24] EPA identified two plants that submitted NOPPs for the low utilization subcategory. EPA used only on-site cost equations from the 2020 rule, as Whitewater Valley and PSNH-Merrimack Station both have landfills containing CCR on-site and are expected to dispose of solids on-site.

plant-specific unitized cost = (impoundment operating unitized cost) × (plant MW factor)

Where:

plant-specific unitized cost	=	Plant-specific cost to operate a front-end loader (in 2021$/ton).
impoundment operating unitized cost	=	2010 unitized annual cost to operate a combustion residual impoundment. EPA used the unitized cost value of $8.06 per ton (in 2021$).
plant MW factor	=	Factor to adjust combustion residual handling costs based on plant capacity

Next, EPA calculated the BA impoundment operating cost savings by multiplying the plant-specific unitized cost by the amount of BA produced by the plant, in tons per year TPY.

BA impoundment operating cost savings (2021$/year) =
(plant-specific unitized cost) × (plant BA tonnage)

Where:

plant-specific unitized cost	=	Plant-specific cost to operate a front-end loader (in 2021$/ton).
plant BA tonnage	=	Total BA tonnage, dry basis, for each plant (in TPY). EPA calculated this value by multiplying the wet BA generation rate (in TPY) for each EGU, then summing the EGU-level values to the plant level.

To calculate BA earthmoving cost savings, EPA first calculated the plant-specific front-end loader unitized cost by multiplying the plant MW factor and the front-end loader unitized cost.

plant-specific front-end loader unitized cost (2021$/ton) =
(front-end loader 2010 unitized O&M cost) × (plant MW factor)

Where:

front-end loader 2021 unitized O&M Cost	=	2010 unitized cost value that represents the O&M of the front-end loader used to redistribute ash at an impoundment. EPA calculated this value to be $2.73 per ton (in 2021$).
plant MW factor	=	Factor to adjust combustion residual handling costs based on plant capacity.

Next, EPA calculated the BA earthmoving cost savings by multiplying the plant-specific unitized cost by the amount of BA tonnage produced by the plant in TPY.

BA impoundment earthmoving cost savings =
(plant-specific front-end loader unitized cost) × (plant BA tonnage)

Where:

plant-specific front-end loader unitized cost	=	Plant-specific cost value that represents the O&M of the front-end loader used to redistribute ash at an impoundment.

plant BA tonnage	=	Total BA tonnage, dry basis, for each plant (in TPY). EPA calculated this value by multiplying the wet BA generation rate in TPY for each EGU, then summing the EGU-level values to the plant level.

EPA calculated 10-year recurring costs associated with operating the earthmoving equipment (*i.e.,* front-end loader) using the estimated cost and average expected life of a front-end loader. EPA determined the cost of the earthmoving equipment to be $520,000 (2021$) and assumed an expected life of 10 years.

EPA then summed the MDS and remote MDS EGU-level costs to the plant level. EPA also added a plant-level capital cost of $1,146,630 (2021$) to build a roof over the remote MDS to mitigate stormwater contributions to the system. This additional roof cost was applied at the plant level because a plant would likely use one roof to cover the entire fleet of remote MDS installations. O&M costs for the roof were assumed to be zero, as the structure is only intended to protect from stormwater and does not have heating, ventilation, or air conditioning (HVAC).

EPA estimated HRR plant-level costs using the following assumptions:

- EPA identified two plants, Whitewater Valley (Plant ID 3024) and PSNH–Merrimack Station (Plant ID 3095), that submitted NOPPs for the low utilization subcategory. For these plants, estimated capital costs are equal to MDS or remote MDS with purge. EPA estimated HRR O&M costs using equations in Section 5.2.2.
- For all other plants with BA discharges, EPA estimated zero capital and zero O&M costs.

5.2.3 Cost Methodology for ZLD

EPA estimated costs to treat a BA transport water purge stream using a high-pressure RO system to remove dissolved solids and facilitate complying with a zero-discharge standard. Based on information provided by industry (expressing concerns about potential adverse consequences associated with long-term closed-loop operation of a remote MDS), and consistent with EPA's purge allowance described in the preamble to the 2020 rule, EPA conservatively assumed a daily purge rate equal to 10 percent of the total estimated BA transport system volume (*i.e.,* the plant-level volume associated with the BA hoppers, remote MDS, sluice pipes, and surge tanks), excluding redundant spare systems, maintenance tanks, and similar infrequently used equipment. Permeate from the RO system would be recycled back into the remote MDS while the RO reject, or brine, would be transported to a centralized waste treatment (CWT) facility for disposal. EPA also assumed that managing the remote MDS as a zero-discharge system may require additional surge tank capacity to hold BA hopper water during maintenance activities. These additional costs associated with zero-discharge operation were calculated at the plant level because one RO system can treat the remote MDS slipstream from all remote MDSs operating at the plant.

For plants identified as likely to install remote MDSs to comply with the 2020 rule or the CCR Part A rule requirements, EPA added capital costs for RO, surge tank, pipe, and pump to the plant-level total remote MDS capital cost described in Section 5.2.2. EPA added O&M costs for the additional equipment and transportation and disposal costs of the RO brine to the remote MDS O&M cost described in Section 5.2.2 to estimate the total cost for a zero-discharge remote MDS. For plants identified as having installed remote MDSs to comply with the 2020 rule, EPA assumed the additional capital and annual O&M costs associated with treating a remote MDS slipstream with RO would be the only incremental costs incurred to operate the system as zero discharge.

To estimate the RO capital and O&M costs, EPA used cost curves from the 2020 rule and escalated them to 2021 dollars as described in Section 5.1.2.

EPA first estimated the total remote MDS volume based on information provided by equipment vendors knowledgeable on boiler configurations (including ash hopper volumes) and remote MDS configurations and sizes. For plant-level capacities less than or equal to 200 MW, EPA assumed the total remote MDS volume is 175,000 gallons based on data provided by vendors and best professional judgement (ERG, 2019b). For plant-level capacities greater than 200 MW, EPA used the following equation, developed from industry-level data on remote MDS installations, to estimate the total system volume (ERG, 2019b).

$$\text{total remote MDS volume (gallons)} = (347.29 \times \text{plant-level capacity}) + 146{,}398$$

Where:

plant level capacity = Sum of EGU capacities (MW) flagged for BA compliance costs.

Based on the estimated total remote MDS volume, EPA calculated the slipstream flow rate in gallons per minute (GPM) as follows:

$$\text{slipstream flow (GPM)} = (\text{total remote MDS volume} \times 0.1/\text{day}) \div 1{,}440 \text{ minutes/day}$$

Where:

Total remote MDS volume = Total volume of all remote MDS expected to be operating at the plant (in gallons).

EPA developed a relationship between total RO capital cost and purge flow, based on data collected from wastewater treatment vendors and best professional judgement (ERG, 2019b). The RO capital cost curve (equation shown below) was used to estimate EGU-level capital costs for RO treatment of the remote MDS slipstream.

$$\text{RO capital cost (2021\$)} = (64{,}545 \times \text{slipstream flow}) + 2{,}521{,}619$$

EPA developed a relationship between annual O&M cost and purge flow, based on data collected from wastewater treatment vendors (ERG, 2019b). The RO O&M cost curve (equation shown below) was used to estimate plant-level annual O&M costs for RO treatment of a BA transport water slipstream from the remote MDS.

$$\text{RO O\&M cost (2021\$)} = \$0.01097 \times \text{slipstream flow} \times 60 \text{ minutes/hour} \times 24 \text{ hours/day} \times 365 \text{ days/year}$$

EPA calculated capital costs for the surge tank. EPA assumed that only one EGU will need to empty the BA hopper at any one time; therefore, EPA developed a relationship between tank size and the capacity of the largest EGU at the plant (defined by capacity in MW) derived from information received by the industry and vendors (ERG, 2019b).

Once the EGU with the largest nameplate capacity (MW) was identified, EPA calculated the size of the surge tank in gallons. EPA accounted for an additional 50 percent capacity for the surge tank by multiplying the relationship by a tank sizing factor (1.5).

$$\text{tank size (gallons)} = 63 \times \text{EGU capacity} \times \text{tank sizing factor}$$

Where:

EGU capacity = Capacity of the EGU (MW).

tank sizing factor = 1.5.

EPA then estimated the cost as a function of tank size based on information provided by vendors during the 2015 rule. For tanks smaller than 50,000 gallons:

$$\text{tank capital cost (2021\$)} = [(2.369 \times \text{tank size}) + 24.9 \times (\text{tank size} \times 1.65)^{0.548}]$$

Where:

tank size = Size of the surge tank (in gallons).

For tanks larger than 50,000 gallons:

$$\text{tank capital cost (2021\$)} = [(3.78 \times \text{tank size}) + 24.9 \times (\text{tank size} \times 1.65)^{0.548}]$$

Where:

tank size = Size of surge tank (in gallons).

EPA estimated the purchased equipment capital costs for the piping and pumps using the methodology for the FGD wastewater recycle piping and wastewater forwarding pumps (to return wastewater back to the scrubber). EPA then calculated the pump as a function of this flow using cost information provided by vendors during the 2015 rule.

$$\text{pump capital cost (2021\$)} = [3{,}227 \times \ln (1.61 \times \text{flow}) - 3{,}389.8] \times 4.56$$

Where:

flow = Daily flow rate from the surge tank (in GPM assuming discharge over five hours).

EPA estimated the capital cost of 2,640 feet of piping using an assumed distance of 0.25 miles between the surge tank and the BA hopper, based on EPA's best professional judgement and information from BA handling vendors about remote MDS placement at a plant, and costs data provided by pipe vendors for the 2015 rule: $41,000 (2021$).

EPA estimated the direct capital costs by multiplying the sum of the purchased equipment costs for the tank, pumps, and piping (*i.e.,* the total purchased equipment cost) by 2. EPA used this relationship to account for delivery of purchased equipment, installation of purchased equipment, instrumentation and controls, piping and electrical, service facilities, building services, and land if purchase is required.

$$\text{direct capital costs} = 2 \times \text{total purchased equipment cost}$$

EPA then estimated the indirect capital costs by multiplying the sum of the total purchased equipment and direct capital costs by 0.43. EPA used this relationship to account for engineering and supervision, construction expenses, contractor's fees, and contingency.

$$\text{indirect capital costs} = 0.43 \times (\text{total purchased equipment cost} + \text{direct capital costs})$$

Finally, EPA estimated total capital costs by summing the total purchased equipment, direct, and indirect capital costs.

$$\text{total capital costs} = \text{total purchased equipment cost} + \text{direct capital costs} + \text{indirect capital costs}$$

EPA calculated plant-level O&M costs associated with operating the surge tank, pumps, and pipe. Total O&M costs include the energy cost associated with operating the pumps and the maintenance cost associated with the surge tank, pumps, and pipes.

$$\text{total tank/pump/pipe O\&M costs} = \text{energy cost} + \text{maintenance cost}$$

To calculate the energy cost, EPA estimated the annual energy requirement to operate the pumps, based on the 2015 rule cost methodology.

$$\text{annual energy requirement (kWh/year)} = (0.02219 \times \text{flow} + 2.019) \times 17.89$$

Where:

Flow = Daily flow rate from the surge tank (in GPM assuming discharge over 5 hours).

EPA estimated the cost of operating the pumps using the pump energy requirement and the national energy cost per kWh, based on data reported by the U.S. EIA (U.S. DOE, 2011), in 2021 dollars.

$$\text{energy cost (2021\$)} = \text{national energy cost} \times \text{annual energy requirement}$$

Where:

national energy cost = (\$0.0485/kWh × 1.097) (in 2021\$).

annual energy requirement = Annual energy requirement to operate pumps (in kWh/year).

For the 2015 rule, EPA developed a relationship between BA slipstream flow and the cost to maintain the surge tank, pumps, and piping to estimate the total maintenance costs.

$$\text{maintenance cost (2021\$)} = 457 \times \text{flow}$$

Where:

Flow = Daily flow rate from the surge tank (in GPM assuming discharge over 5 hours).

To estimate costs for transportation and disposal of the RO brine, EPA calculated O&M costs associated with hauling the brine off site to a CWT and the costs incurred for using a CWT.

EPA calculated brine flow rate based on the average recovery from the membrane treatment vendors used for FGD wastewater.

$$\text{brine flow} = 0.30 \times \text{purge flow}$$

EPA estimated the weight of the brine based on the weight of the solids in the brine and the weight of the water. Solids in the brine were estimated based on the average total suspended solids (TSS)[25] concentration in BA transport water for the entire purge flow (this assumes that all suspended solids from the BA purge will be retained in the brine, which is likely an overestimate).

$$\text{annual brine solids (tons/year)} = \text{BA purge (GPD)} \times \text{average TSS concentration} \times 3.78\ \text{L/gal} \times 0.001\ \text{g/mg} \times (1.102 \times 10^{-6}\ \text{tons/g}) \times 365\ \text{days per year}$$

Where:

BA purge = 10 percent of the total BA system volume in GPD.

average TSS concentration = Average TSS concentration in BA transport water (see Table 6-2 of the Supplemental TDD), 13.4 mg/L.

$$\text{annual brine water weight (TPY)} = \text{brine flow (GPD)} \times 0.00417\ \text{tons/gal} \times 365\ \text{days per year}$$

EPA calculated the total weight of brine to be disposed of annually as the sum of the brine solids and the water weight.

$$\text{annual brine weight (tons/year)} = \text{annual brine solids} + \text{annual brine water weight}$$

[25] EPA expects to update the average TSS concentration with average TDS concentration (1,290 mg/L TDS) for future cost analyses. This would affect the brine annual transportation and disposal cost by less than one percent.

EPA estimated the annual cost of transporting brine solids to a CWT facility using the 2015 methodology for off-site transportation, which is based on transportation of solids to an off-site location 25 miles from the plant.

transportation cost (2021$) = annual brine weight × $10.10 per ton

EPA estimated disposal costs using data compiled as part of the rulemaking establishing pretreatment standards for Oil and Gas Extraction, Subpart C (i.e., onshore unconventional oil and gas). Wastewater management using a CWT for total dissolved solids (TDS) removal ranged from $3 to $11 per barrel (U.S. EPA, 2016). Using the average value of $7 per barrel, EPA estimated disposal cost at a CWT of $0.167/gallon (2005$), which escalated to $0.183/gallon in 2021$. Annual disposal costs were estimated using the following equation:

disposal cost (2021$) = brine flow (GPD) × $0.183/gallon

To estimate the annual cost for brine transportation and disposal, EPA summed the transportation and disposal costs.

brine T&D annual cost = transportation cost + disposal cost

EPA estimated ZLD plant-level costs according to the following assumptions:

- For plants opting in to the low utilization subcategory, EPA estimated costs equal to an MDS or a remote MDS with a purge. For a plant to achieve ZLD, the steps outlined in Section 5.2.3 must be added to the plant's overall cost calculation from Section 5.2.2.
- For all other plants with BA discharges, EPA estimated costs equal to the addition of an RO system only.

5.3 Combustion Residual Leachate

For the proposed rule, EPA estimated costs for plants to install and operate CP treatment of CRL. EPA included the following treatment components for CRL:

- CP treatment equipment (equalization and storage tanks, pumps, reaction tanks, solids-contact clarifier, and gravity sand filter).
- CP chemical feed systems for lime, organosulfide, ferric chloride, and polymers.
- CP solids-contact clarifier to remove suspended solids.
- Mercury analyzer.
- Compliance monitoring (including sample collection and analysis).
- Solids handling (sludge holding tank and filter press).
- Transportation and disposal of solids in a landfill.

Section 5.3.1 describes the process for developing the CRL cost calculation inputs.

As described in Section 3.2.3, EPA also notes that unlined landfills and surface impoundments potentially discharge CRL through groundwater before entering surface water. To evaluate the potential costs and loads of such discharges, EPA conducted a sensitivity analysis documented in its memorandum *Evaluation of Potential CRL in Groundwater* (U.S. EPA, 2023a).

5.3.1 CRL Cost Calculation Inputs

To estimate plant-level baseline and post-compliance costs of implementing CRL treatment technologies, EPA developed a cost calculation database. This database uses plant-specific input values including CRL flow and existing treatment in combination with relationships between costs and CRL flow rates described in Section 5.3.2 to estimate baseline and post-compliance costs for each plant (ERG, 2023b). For this proposal, EPA started with input data from the 2015 rule, including the Steam Electric Survey, and then updated the data with other publicly available data described in Section 2. This section describes the cost inputs.

5.3.1.1 Population

EPA identified the population of landfills containing combustion residuals that collect and discharge leachate to surface waters or POTWs using data from the Steam Electric Survey (U.S. EPA, 2015). EPA updated this population to reflect recent changes to the profile of steam electric power plants. After removing plants where all EGUs will be retired by December 31, 2023, EPA added plants that have constructed new landfills since 2015 using data from utilities' "CCR Rule Compliance Data and Information" websites.

For each new landfill, EPA used data from the Steam Electric Survey to identify the most appropriate discharge location and receiving water. Where a plant reported all discharges to a single receiving water (*i.e.,* all outfalls discharge to the same waterbody), EPA used this receiving water. Where a plant reported discharges to multiple waterbodies, EPA evaluated outfall data and water balance diagrams to identify the most appropriate receiving water for leachate.

5.3.1.2 Flow Rate

EPA used the methodology described in Section 9.4.1 of the 2015 TDD to estimate CRL flow rates. Where information on leachate flow rate was available in the Steam Electric Survey, EPA used this value. Where landfill size (acreage) information was available in the Steam Electric Survey, EPA estimated that plants collect leachate from 75 percent of the total acreage for active landfills and 5 percent of the total acreage for inactive landfills. EPA also used survey data to estimate the leachate flow based on this landfill size.

For active landfills:

$$\text{leachate flow (GPD)} = 887 \times 0.75 \times \text{leachate acreage}$$

For inactive landfills:

$$\text{leachate flow (GPD)} = 887 \times 0.05 \times \text{leachate acreage}$$

Where no leachate flow or landfill size information was available, EPA used the median leachate volume from the Steam Electric Survey, 46,160 gallons per day.

5.3.1.3 Treatment-in-Place Data

In 2015, 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. In 2020, EPA also identified one plant currently operating a thermal treatment system to treat landfill leachate (combined with FGD wastewater) (ERG, 2020e). EPA did not identify any other plants with treatment in place for the proposed rule.

5.3.2 Cost Methodology for CP

To estimate CP costs for CRL, EPA used cost data from the 2015 and 2020 rules for CP as stand-alone treatment for FGD wastewater. Starting with the capital and O&M cost curves presented in Section 5.2.2 of the 2020 TDD, EPA sized the treatment system for leachate flows (rather than FGD flows). EPA used only cost curves for on-site transportation and disposal, as all plants with leachate have landfills. EPA updated the 2020 rule cost curves by escalating them to 2021 dollars as described in Section 5.1.2.

EPA used the following cost curves to estimate CP capital and O&M costs:

$$\text{CP capital costs (2021\$)} = 38.35 \times \text{leachate flow} + 7{,}724{,}092.2$$

$$\text{CP O\&M costs (2021\$/year)} = 4.4385 \times \text{leachate flow} + 251{,}880$$

The CP system includes an in-line mercury analyzer. This process control mechanism has an expected life of six years. EPA estimated this six-year recurring cost to replace the mercury analyzer using costs originally obtained for the 2015 rule and escalating them to 2021 dollars: $110,039 (2021$).

Where existing treatment of leachate was identified, EPA estimated no additional capital costs or recurring costs, but estimated O&M costs equal to $80,739 to account for compliance monitoring of the treated effluent. Compliance monitoring includes sampling labor and materials as well as the costs associated with sample preservation, shipping, and analysis for the pollutants selected for regulation (arsenic and mercury).

5.4 Summary of National Engineering Costs for Regulatory Options

To estimate total industry compliance costs for each regulatory option, EPA first estimated plant-level FGD wastewater, BA transport water, and CRL compliance costs (as described in Sections 5.1, 5.2, and 5.3) for all technologies evaluated. Next, EPA estimated EGU-level costs (including capital, O&M, one-time, 5-, 6-, and 10-year recurring costs) using the equation below.

$$\text{EGU-level cost} = \text{plant-level cost} \times (\text{EGU-level capacity} \div \text{plant-level capacity})$$

Where:

plant-level cost = Technology option plant-level cost in 2021$. Includes capital, O&M, one-time, and recurring costs.

EGU-level capacity = EGU-level generating nameplate capacity in MW (from the Steam Electric Survey and 2018 Form EIA-860 data for new EGUs).

plant-level capacity = Plant-level generating nameplate capacity in MW (from Form EIA-860 data for 2020).

For each EGU, EPA chose the appropriate technology cost to coincide with the regulatory option being evaluated. See the preamble for details on the combinations of wastestreams and treatment technologies based on the regulatory option. EPA then summed the EGU-level costs for only those EGUs included in each regulatory option to estimate total industry-level regulatory option costs. See the *Generating Unit-Level Regulatory Option Costs and Loads Memorandum* for the details by EGU on technologies selected for each regulatory option and estimates of compliance costs (U.S. EPA, 2023h).

Table 10, Table 11, and Table 12 present the total industry compliance cost estimates for FGD wastewater, BA transport water, and CRL, respectively, by regulatory option. For each wastestream, the number of plants incurring costs is also included for each evaluated option. Table 13 presents the aggregated, industry-level compliance costs by regulatory option. All cost estimates are expressed in pre-tax 2021 dollars and represent costs that would be incurred once all plants and EGUs achieve compliance with the regulatory option presented. Values presented in this document do not account for the timing or exact date of implementation (*e.g.,* when costs are incurred by the industry).

Table 10. Estimated Cost of Implementation for FGD Wastewater by Regulatory Option (in Millions of Pre-tax 2021 Dollars)

Regulatory Option	Number of Plants	Capital Cost	Annual O&M Cost	One-time Costs	5-Year Recurring Cost	6-Year Recurring Cost	10-Year Recurring Cost
Baseline	29	$0	$0	$0	NA	NA	NA
1	29	$0	$0	$0	NA	NA	NA
2	29 [a]	$547	$47.0	$2.51	NA	NA	NA
3	29 [b]	$547	$47.0	$2.85	NA	NA	NA
4	29 [c]	$604	$53.4	$0	NA	NA	NA

Note: Costs and savings are rounded to three significant figures.

NA: Not applicable.

a – Seven of these plants incur zero cost, resulting in 22 plants with non-zero estimated costs for implementation of Regulatory Option 2.

b – Seven of these plants incur zero cost, resulting in 22 plants with non-zero estimated costs for implementation of Regulatory Option 3.

c – Three of these plants incur zero cost, resulting in 26 plants with non-zero estimated costs for implementation of Regulatory Option 4.

Table 11. Estimated Cost of Implementation for BA Transport Water by Regulatory Option (in Millions of Pre-tax 2021 Dollars)

Regulatory Option	Number of Plants	Capital Cost	Annual O&M Cost	One-time Costs	5-Year Recurring Cost	6-Year Recurring Cost	10-Year Recurring Cost [a]
Baseline	42	$0	$0	NA	$0	NA	$0
1	42 [b]	$21.9	$1.97	NA	$0.451	NA	($0.520)
2	42 [b]	$21.9	$1.97	NA	$0.451	NA	($0.520)
3	42 [c]	$257	$27.3	NA	$0	NA	$0
4	42 [d]	$263	$27.9	NA	$0	NA	$0

Note: Costs and savings are rounded to three significant figures.

NA: Not applicable.

a – The values in this column are negative and presented in parentheses because they represent cost savings.

b – 41 of these plants incur zero cost, resulting in one plant with non-zero estimated costs for implementation of Regulatory Options 1 and 2.

c – Seven of these plants incur zero cost, resulting in 35 plants with non-zero estimated costs for implementation of Regulatory Option 3.

d – Six of these plants incur zero cost, resulting in 36 plants with non-zero estimated costs for implementation of Regulatory Option 4.

Table 12. Estimated Cost of Implementation for Combustion Residual Leachate by Regulatory Option (in Millions of Pre-tax 2021 Dollars)

Regulatory Option	Number of Plants	Capital Cost	Annual O&M Cost	One-time Costs	5-Year Recurring Cost	6-Year Recurring Cost	10-Year Recurring Cost
Baseline	69	$0	$0	NA	NA	$0	NA
1	69	$747	$43.5	NA	NA	$7.37	NA
2	69	$747	$43.5	NA	NA	$7.37	NA

Table 12. Estimated Cost of Implementation for Combustion Residual Leachate by Regulatory Option (in Millions of Pre-tax 2021 Dollars)

Regulatory Option	Number of Plants	Capital Cost	Annual O&M Cost	One-time Costs	5-Year Recurring Cost	6-Year Recurring Cost	10-Year Recurring Cost
3	69	$747	$43.5	NA	NA	$7.37	NA
4	69	$747	$43.5	NA	NA	$7.37	NA

Note: Costs and savings are rounded to three significant figures.

NA: Not applicable.

Table 13. Estimated Cost of Implementation by Regulatory Option (in Millions of Pre-tax 2021 Dollars)

Regulatory Option	Number of Plants	Capital Cost	Annual O&M Cost	One-time Costs	5-Year Recurring Cost	6-Year Recurring Cost	10-Year Recurring Cost [a]
Baseline	97	$0	$0	$0	$0	$0	$0
1	97 [b]	$768	$45.5	$0	$0.451	$7.37	($0.520)
2	97 [c]	$1,320	$92.5	$2.51	$0.451	$7.37	($0.520)
3	97 [d]	$1,550	$118	$2.85	$0	$7.37	$0
4	97 [e]	$1,610	$125	$0	$0	$7.37	$0

Note: Costs and savings are rounded to three significant figures.

NA: Not applicable.

a – The values in this column are negative and presented in parentheses because they represent cost savings.

b – 28 of these plants incur zero cost, resulting in 69 plants with non-zero estimated costs for implementation of Regulatory Option 1.

c – 19 of these plants incur zero cost, resulting in 78 plants with non-zero estimated costs for implementation of Regulatory Option 2.

d – Six of these plants incur zero cost, resulting in 91 plants with non-zero estimated costs for implementation of Regulatory Option 3.

e – Five of these plants incur zero cost, resulting in 92 plants with non-zero estimated costs for implementation of Regulatory Option 4.

6. Pollutant Loadings and Removals

This section describes the annual pollutant discharge loading estimates for the steam electric power generating industry and pollutant loading removal estimates associated with the proposed rule. Estimates for the 2023 proposed rule build on the pollutant loadings and removals calculations for regulated wastestreams from the 2015 and 2020 rules. Section 10 of the 2015 Technical Development Document (2015 TDD) includes pollutant loadings and removals estimates for flue gas desulfurization (FGD) wastewater, bottom ash (BA) transport water, and combustion residual leachate (CRL) (U.S. EPA, 2015a). Section 6 of the 2020 rule TDD estimates FGD wastewater and BA transport water pollutant removals as the change in loadings from the 2015 to the 2020 regulatory requirements. For this 2023 proposed rule, EPA estimated pollutant loadings and removals for the three wastestreams for which this proposal is establishing new requirements (FGD wastewater, BA transport water, and CRL). EPA evaluated loadings and removals for the same industry population for which EPA estimated regulatory compliance costs (refer to Section 5 for the industry population evaluated for this proposal). EPA estimated baseline and post-compliance pollutant loadings and pollutant removals as follows:

- *Baseline loadings*. Pollutant loadings, in pounds per year, in wastewater discharged to surface water or through publicly owned treatment works (POTWs) to surface water under 2020 final rule conditions. For FGD wastewater and BA transport water, baseline loadings characterize wastewater discharged from plants assumed to be in full compliance with the requirements of the 2020 rule; for CRL, baseline loadings characterize current discharges.
- Post-compliance loadings. Pollutant loadings, in pounds per year, in wastewater discharged to surface water or through POTWs to surface water after full implementation of the 2023 proposed rule technology options. EPA estimated post-compliance pollutant loadings with the expectation that all steam electric power plants subject to the requirements of the proposed rule will 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.

This section describes EPA's methodology for estimating plant-specific pollutant loadings and removals as well as industry-level results for each of the 2023 proposed regulatory options:

- General methodology for estimating pollutant removals (Section 6.1).
- FGD wastewater (Section 6.2).
- BA transport water (Section 6.3).
- CRL (Section 6.4).
- Summary of industry-level baseline and regulatory option loadings and removals (Section 6.5).

6.1 General Methodology

For each plant discharging FGD wastewater, BA transport water, and/or CRL, EPA estimated plant-level baseline loadings and post-compliance loadings and removals for each of the technology options described in Section 5. EPA used sampling data collected in support of the 2015 rule and 2020 rule to characterize baseline and post-compliance pollutant concentrations, including data from EPA's sampling program (described in Section 3 of the 2015 TDD), the Steam Electric Survey, public comments, industry submissions, and publicly available data sources. EPA evaluated these data sources to identify analytical data that meet EPA's acceptance criteria for inclusion in analyses for characterizing discharges of FGD wastewater, BA transport water, and CRL. EPA's acceptance criteria include:

- Sample locations must be unambiguous and clearly described such that the sample can be categorized by wastestream and level of treatment (e.g., untreated, partially treated).
- Analytical data must provide sufficient information to identify units of measure and determine usability in EPA's analyses.
- Analytical data must represent individual sample results, rather than average results for multiple plants or long-term averages for single plants.[26]
- Analytical data must not be duplicative of other accepted data.
- Sample analyses must be performed using accepted analytical methods.
- Nondetect results are not acceptable if no detection or quantitation limit is provided.
- Sample results must represent total results for a pollutant (*i.e.,* dissolved results are not acceptable except for total dissolved solids).
- For biphasic samples, sample results must include both phases.

To ensure analytical data were representative, EPA excluded data that did not meet the acceptance criteria as they were not fit for use in estimating pollutant loadings. Sections 6.2.2, 6.3.2, and 6.4.2 describe additional wastestream-specific data acceptance criteria and present the average discharge pollutant concentrations used to estimate baseline and post-compliance loadings for FGD wastewater, BA transport water, and CRL, respectively.

First, EPA calculated baseline loadings and post-compliance loadings for each plant using the plant-specific wastewater flow for the wastestream (as described in Section 5) and average pollutant concentrations for the specific wastestream using the following equation:

$$Loading_{pollutant}\text{ (lb/year)} = \text{flow rate} \times \text{discharge days} \times Conc_{pollutant} \times (2.20462\text{ lb}/10^9\ \mu\text{g}) \times (1{,}000\text{ L}/264.17\text{ gallons})$$

Where:

Flow rate	=	Reported flow rate of the waterstream being discharged, in gallons per day, from the plant
Discharge days	=	number of days per year the waterstream is discharged from the plant.
$Conc_{pollutant}$	=	Concentration of a specific pollutant in the wastestream, in micrograms per liter (µg/L). Refer to Table 15 for FGD wastewater, Table 16 for BA transport water, and Table 17 for CRL.

EPA identified several plants that reported transferring wastewater to POTWs rather than directly discharging to surface waters. For these plants, EPA adjusted the baseline and post-compliance loadings to account for pollutant removals expected during treatment at a well-operated POTW for each pollutant, shown in Table 14. EPA used the following equation to adjust baseline and post-compliance loading estimates for each pollutant to account for removals achieved by the POTW:

$$Loading_{pollutant\_indirect}\text{ (lb/year)} = Loading_{pollutant} \times (1 - (Removal_{POTW}/100))$$

Where:

$Loading_{pollutant}$	=	Estimated pollutant loading from a specific pollutant if it was being discharged directly to surface water, in pounds per year.

[26] Where individual sample results and plant-level average sample concentrations were both available for a data set, EPA preferentially used the individual sample results.

$Removal_{POTW}$ = Estimated percentage of the pollutant loading that would be removed by a POTW (see Table 14).

Finally, EPA calculated pollutant removals (*i.e.,* the change in pollutant loadings) for each plant by subtracting the baseline loadings from the post-compliance loadings, as shown in the following equation:

$$Removal_{pollutant}\ (lb/year) = Loading_{post\text{-}compliance} - Loading_{baseline}$$

Where:

$Loading_{post\text{-}compliance}$ = Estimated pollutant loading discharged for a specific pollutant for the post-compliance technology option, in pounds per year (accounting for removals achieved by POTWs where appropriate).

$Loading_{baseline}$ = Estimated pollutant loading discharged for a specific pollutant for the baseline technology option, in pounds per year (accounting for removals achieved by POTWs where appropriate).

Table 14. POTW Removals

Pollutant	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%

Table 14. POTW Removals

Pollutant	Median POTW Removal Percentage
Tin	NA
Titanium	NA
Total dissolved solids	NA
Total suspended solids	NA
Vanadium	8.3%
Zinc	79.1%

Source: ERG, 2005.

NA—not available.

6.2 FGD Wastewater

For each plant discharging FGD wastewater, as described in Section 5, EPA estimated three pollutant loading values:

- Baseline conditions, where plants were assumed to comply with the 2020 rule.
- Compliance with the chemical precipitation followed by low residence time reduction (CP+LRTR) technology option.
- Compliance with the membrane filtration technology option.

As noted in Section 6.1, EPA calculated pollutant loadings using a flow rate multiplied by an average pollutant concentration. For the 2023 proposal, EPA used data from the 2020 rule to characterize pollutant concentrations in FGD wastewater. See the *Development Memo for FGD Wastewater Data in the Analytical Database* for details on the acceptance criteria used to generate EPA's FGD analytical data set (ERG, 2015a). Table 15 presents the average effluent concentrations for CP+LRTR treatment. Regarding membrane treatment, EPA expects that plants will choose to reuse permeate as FGD scrubber make-up; therefore, membrane filtration average effluent concentrations were assumed to be zero.

As noted in the 2020 TDD, EPA supplemented these analytical data with additional data for bromide and iodide. Because sampling data for these pollutants were insufficient, EPA developed a methodology to estimate pollutant loadings from both the naturally occurring bromine and iodine in the coal burned and any bromide or iodide additives that were being used for mercury emission control at each plant. This methodology is described in the *FGD Halogen Loadings from Steam Electric Power Plants Memorandum* (U.S. EPA, 2022c).

Section 6.2.1 describes FGD wastewater flow rates used for pollutant loading calculations, and Section 6.2.2 discusses EPA's methodology for estimating baseline and post-compliance loadings.

Table 15. Average CP+LRTR Effluent Concentrations

Pollutant	Average Concentration (µg/L)
Conventional Pollutants	
Total suspended solids	8,590
Priority pollutants	
Antimony	4.25
Arsenic	5.83
Beryllium	1.34
Cadmium	4.21
Chromium	6.45
Copper	3.78

Table 15. Average CP+LRTR Effluent Concentrations

Pollutant	Average Concentration (µg/L)
Cyanide, total	949
Lead	3.39
Mercury	0.0507
Nickel	6.30
Selenium	5.72
Thallium	9.81
Zinc	20.0
Nonconventional Pollutants	
Aluminum	120
Ammonia as N	6,850
Barium	140
Boron	225,000
Calcium	1,920,000
Chloride	7,120,000
Cobalt	9.30
Iron	110
Magnesium	3,370,000
Manganese	12,500
Molybdenum	125
Nitrate nitrite as N	647
Phosphorus, total	319
Sodium	276,000
Titanium	9.30
Total dissolved solids	24,100,000
Vanadium	12.6

Source: U.S. EPA, 2015a ERG, 2023c.

Note: Concentrations are rounded to three significant figures

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6.2.1 FGD Wastewater Flows

To estimate all pollutant loadings, EPA used the same set of flow rates as described in Section 5.1.1 for compliance cost estimates. As in the 2020 rule, EPA used optimized flow rates, consistent with the O&M compliance cost assumption that plants will choose to optimize FGD flow through their treatment system.

6.2.2 Baseline and Post-compliance Loadings

EPA multiplied the average effluent pollutant concentrations shown in Table **15** by the plant-specific FGD wastewater optimized flow rate described in Section 6.2.1 to calculate the pollutant loadings discharged to surface water for each plant. EPA did not identify any plants transferring FGD wastewater to a POTW.[27]

6.2.2.1 Baseline Loadings

For all plants discharging FGD wastewater that did not opt into the Voluntary Incentive Programn (VIP), EPA used CP+LRTR concentrations from Table 15 to represent baseline. EPA assumes that plants subject

[27] EPA previously identified two plants for the 2020 rule that reported transferring FGD wastewater to a POTW. CWLP Dallman has since installed an enhanced chemical precipitation system to treat FGD wastewater with the option to directly discharge (U.S. EPA, 2022a). C.D. McIntosh Jr. Power Plant (City of Lakeland, FL) retired in 2021.

to the 2020 rule have installed the Best Available Technology Economically Achievable (BAT), CP+LRTR, or equivalent technology.

For plants that opted into the VIP, EPA estimated baseline loadings of zero, reflecting membrane filtration treatment and reuse. EPA assumes that plants will choose to reuse membrane permeate within the plant rather than discharge permeate and monitor the effluent for compliance with NPDES permit limitations, due to the cost associated with monitoring and potential for noncompliance.

6.2.2.2 CP+LRTR Post-compliance Loadings

For the CP+LRTR technology option, EPA assumed that plants already comply with the 2020 rule and estimated post-compliance loadings identical to baseline loadings.

6.2.2.3 Membrane Filtration Post-compliance Loadings

For the membrane filtration technology option, EPA estimated post-compliance loadings of zero for all plants discharging FGD wastewater.

6.3 BA Transport Water

For each plant discharging BA transport water, as described in Section 5, EPA estimated three pollutant loading values:

- Baseline conditions based on a high rate recycle system with a purge.
- Compliance with the dry handling or high rate recycle BA system with a purge (high recycle rate, or HRR) technology option.
- Compliance with the zero liquid discharge (ZLD) technology option.

As noted in Section 6.1, pollutant loadings were calculated using a flow rate multiplied by average pollutant concentrations. For the 2023 proposal, EPA used data from the 2020 rule to characterize pollutant concentrations in BA transport water. See the *Development of the Bottom Ash Transport Water Analytical Dataset and Calculation of Pollutant Loadings for the Steam Electric Effluent Guidelines Proposed Rule* for additional details on EPA's data sources, acceptance criteria, and development of the analytical data set used to characterize BA transport water (ERG, 2019b).

Data for BA transport water were typically collected from surface impoundments that receive multiple wastestreams, and these different wastestreams have the potential to dilute or otherwise alter the characteristics of the impoundment effluent. Because of this, EPA has additional acceptance criteria specific to BA transport water samples:

- Sample must be at least 75 percent by volume BA transport water and not include any contribution of fly ash transport water.
- Sample must be representative of actual BA surface impoundment effluent collected during full-scale, typical plant operations.

EPA used the BA transport water analytical data to calculate an industry average concentration for each pollutant present.[28] Table 16 presents the average effluent concentrations for pollutants present in BA transport water.

[28] BA surface impoundments typically include other wastestreams (*e.g.,* low volume wastewaters, cooling water); as a result, the effluent concentrations due to BA transport water are likely suppressed somewhat due to dilution. Because of this, baseline pollutant loadings and post-compliance pollutant loadings are underestimated to some degree. Nevertheless, EPA considers that the pollutant removal estimates calculated for this rule represent a

Table 16. Average BA Transport Water Effluent Concentrations

Pollutant	Average Concentration (µg/L)
Conventional Pollutants	
Chemical oxygen demand	20,800
Total suspended solids	13,400
Priority Pollutants	
Antimony	17.3
Arsenic	9.32
Cadmium	0.721
Chromium	5.08
Copper	3.95
Lead	10.4
Mercury	0.102
Nickel	17.5
Selenium	12.3
Thallium	1.13
Zinc	33.8
Nonconventional Pollutants	
Aluminum	854
Barium	106
Boron	5,310
Bromide	5,100
Calcium	154,00
Chloride	321,000
Cobalt	9.19
Iron	676
Magnesium	55,700
Manganese	153
Molybdenum	28.3
Nitrate-nitrite as N	1,670
Phosphorus	222
Potassium	19,600
Silica	8,160
Sodium	119,000
Strontium	1,430
Sulfate	504,000
Sulfite	3,920
Titanium	35.9
Total dissolved solids	1,290,000
Total Kjeldahl nitrogen	968
Vanadium	10.1

Sources: U.S. EPA, 2015a; ERG, 2023d.

Notes: Concentrations are rounded to three significant figures. EPA did not calculate average pollutant concentrations for pollutants where all sample results are less than the quantitation limit.

EPA identified ammonia (as N) as a pollutant present in BA transport water; however, EPA excluded this parameter from the calculation of pollutant loadings to avoid double-counting of nitrogen compounds. EPA has no data on iodine concentrations in BA transport water and therefore could not calculate an average pollutant concentration.

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reasonable estimate of the degree of pollutant removal that would be achieved by the BAT/Pretreatment Standards for Existing Sources (PSES) limitations.

6.3.1 BA Transport Water Flows

To estimate all pollutant loadings, EPA used the same set of flow rates as described in Section 5.2.1 for compliance cost estimates.

6.3.2 Baseline and Post-compliance Loadings

For baseline and post-compliance loadings, EPA calculated electric generating unit (EGU)–level pollutant loadings by multiplying the average concentration of each pollutant in Table 16 by the EGU-level discharge flow rate described in Section 6.3.1. Using the EGU-level loadings, EPA then calculated the baseline and post-compliance loadings for each plant as the sum of pollutant loadings for all EGUs. EPA did not identify any plants transferring BA transport water to a POTW.

6.3.2.1 Baseline Loadings

For all plants discharging BA transport water, EPA used BA transport water concentrations from Table 16 to represent baseline. EPA assumed that plants subject to the 2020 rule have installed BAT, HRR using a mechanical drag system (MDS) or remote MDS, both with a purge option. If a plant falls under the low utilization subcategory, EPA assumed post-compliance loadings reflecting a surface impoundment plus best management practices (BMP) plan[29].

6.3.2.2 HRR Post-Compliance Loadings

Under the HRR technology option, which would allow plants to discharge a portion of their BA transport water, EPA estimated loadings associated with MDS and remote MDS installations with a purge. EPA assumed that plants that already have HRR technologies installed have post-compliance loadings identical to baseline loadings.

6.3.2.3 ZLD Post-Compliance Loadings

Under the ZLD technology option, EPA estimated pollutant loadings associated with MDS and closed loop remote MDS installations. Closed loop remote MDS installations include a reverse osmosis (RO) system to allow for complete recycle. EPA estimated post-compliance loadings of zero for all plants.

6.4 CRL

EPA estimated CRL pollutant loadings under baseline conditions as well as for the chemical precipitation (CP) technology option. EPA used data collected through the Steam Electric Survey from the 2015 rule to estimate the average effluent concentrations for untreated CRL. As described in the 2015 TDD, EPA combined data from 26 landfills reported in the Steam Electric Survey to estimate the average effluent concentration of landfill leachate (U.S. EPA, 2015b). These average concentrations are presented in Table 17. EPA used all data provided by the plants in the Steam Electric Survey, except for the following:

- For any value reported as less than the quantitation limit, EPA assumed the concentration was equal to 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.

In 2015, EPA identified one plant operating a biological treatment system to treat landfill leachate (combined with FGD wastewater) and one plant building a biological treatment system to treat its landfill

[29]For plants subject to the implementation of a BMP plan under the 2020 rule subcategories, EPA assumed that the plant will continue to discharge BA transport water consistent with current operations (i.e., the BA sluice flow rate). EPA used information from the Steam Electric Survey to calculate a normalized BA transport water discharge flow rate consistent with the methodology described in Section 10.3.2 of the 2015 TDD (U.S. EPA, 2015a).

CRL. As described in Section 5.3.1, EPA accounted for this treatment-in-place information in the 2023 proposal analyses.

At the time loading estimates for the proposed rule were calculated, EPA did not have analytical data from steam electric power plants using CP or biological treatment to treat landfill leachate; therefore, EPA used the same methodology as that of the 2015 rule, transferring the average FGD effluent concentrations for CP and biological treatment. These concentrations are presented in Table 17.

Table 17. Average CRL Pollutant Concentrations

Pollutant	Untreated CRL Average Concentration (µg/L)	Chemical Precipitation Average Concentration (µg/L)	Biological Treatment Average Concentration (µg/L)
Conventional Pollutants			
Total suspended solids	35,800	8,590	8,590
Priority Pollutants			
Antimony	3.75	3.75	3.75
Arsenic	38.4	5.83	5.83
Cadmium	10.1	4.21	4.21
Chromium	2,120	6.45	6.45
Copper	7.58	3.78	3.78
Mercury	1.06	0.139	0.0507
Nickel	46.5	9.11	6.30
Selenium	111	111	5.72
Thallium	1.16	1.16	1.16
Zinc	211	20.0	20.0
Nonconventional Pollutants			
Aluminum	2,990	120	120
Barium	53.2	53.2	53.2
Boron	22,400	22,400	22,400
Calcium	408,000	408,000	408,000
Chloride	413,000	413,000	413,000
Cobalt	38.6	9.30	9.30
Iron	37,100	110	110
Magnesium	118,000	118,000	118,000
Manganese	2,720	2,720	2,720
Molybdenum	1,380	125	125
Sodium	308,000	276,000	276,000
Sulfate	1,790,000	1,240,000	1,240,000
Total dissolved solids	3,500,000	3,500,000	3,500,000
Vanadium	1,910	12.6	12.6

Sources: U.S. EPA, 2015a; ERG, 2023e.

In cases where the average concentration of the untreated CRL was less than the FGD treated concentration for the technology option, EPA assumed that the treated concentration was equal to the untreated CRL average concentration. EPA did not calculate removals of these particular pollutants by the wastewater treatment system.

As described in Section 3.2.3, EPA also notes that unlined landfills and surface impoundments potentially discharge CRL through groundwater before entering surface water. To evaluate the potential costs and loads of such discharges, EPA conducted a sensitivity analysis documented in its memorandum *Evaluation of Potential CRL in Groundwater* (U.S. EPA, 2023a).

6.4.1 CRL Flows

As described in Section 5.3.1, EPA used the same methodology from the 2015 rule to estimate CRL flow rates for the proposed rule, with estimates deriving from the Steam Electric Survey.

6.4.2 Baseline and Post-compliance Loadings

To estimate baseline and post-compliance loadings for the 2023 proposal, EPA multiplied the appropriate average effluent pollutant concentrations from Table 17 by the plant-specific CRL flow rate to calculate the pollutant loadings for each plant. For plants with new landfills, and those not included in the 2015 Rule population, ERG used the average landfill leachate flow per landfill (46,160 gpd). This average flow is based on the 2015 methodology and data from the Steam Electric Survey and was used for plants where a flow rate could not be determined. See Section 4.1.3.1 of EPA's 2015 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, 2015b). Calculations for both baseline and the CP technology option use the same CRL flow rate. EPA adjusted pollutant loadings for plants discharging to a POTW to account for additional removals achieved by the POTW.

6.4.2.1 Baseline Loadings

For all plants except those with treatment in place, EPA estimated baseline loadings using the untreated concentrations shown in Table 17.

For the two plants with biological treatment in place for landfill leachate, EPA used a methodology consistent with the 2015 rule and transferred the effluent concentrations from the FGD biological treatment, shown in Table 17, to calculate baseline loadings.

6.4.2.2 CP Post-compliance Loadings

To estimate CP post-compliance loadings for those plants without leachate treatment in place, EPA used plant-specific CRL flow rates and the CP effluent concentrations shown in Table 17. For the two plants with biological treatment, EPA estimated option loadings identical to baseline loadings.

6.5 Summary of Baseline and Regulatory Option Loadings and Removals

EPA evaluated four regulatory options to control FGD wastewater, BA transport water, and CRL discharges. For each regulatory option, EPA combined the wastestream-level pollutant loadings for baseline and each technology option to obtain total regulatory option loadings; EPA also calculated pollutant removals as the difference between baseline and each regulatory option (ERG, 2023f). This section discusses the specific loadings and removals calculations for each regulatory option evaluated by EPA. This section also presents aggregated industry-level loadings and removals for each wastestream and regulatory option.

EPA applied different effluent limitations to the following:

- Steam electric EGUs with less than 50 megawatts generating capacity.
- EGUs with a specific net power generation.
- Early adopters of the 2020 rule FGD wastewater BAT limitations.
- Plants that opted into the 2020 rule VIP.

In calculating the pollutant loading estimates for each regulatory option, EPA considered the subcategorizations established by each option. The preamble describes the subcategories and requirements applicable for each of the regulatory options evaluated by EPA.

Table 18, Table 19, and Table 20 present EPA's estimated total industry pollutant loadings and removals for FGD wastewater, BA transport water, and CRL, respectively, in pounds per year for baseline and each regulatory option. Table 21 presents EPA's aggregated, industry-level pollutant loadings and removals at baseline and each regulatory option. Pollutant loadings and removals presented in these tables are calculated as the sum of TDS and TSS. EPA estimated the pollutant removals by subtracting the post-compliance loadings from the baseline loadings. The *Generating Unit-Level Costs and Loadings Estimates by Regulatory Option* memorandum presents the baseline and post-compliance loadings for each wastestream and each regulatory option at the plant level (U.S. EPA, 2023h). Post-compliance loadings represent loadings once all plants and EGUs comply with the regulatory option presented. Values presented in this document do not account for the timing or exact date of implementation (*e.g.,* when treatment systems are installed by the industry).

Table 18. Estimated Industry-Level FGD Wastewater Pollutant Loadings and Removals by Regulatory Option

Regulatory Option	Estimated Total Industry Loadings (lb/Year)	Estimated Total Industry Removals (lb/Year)
Baseline	612,000,000	-
1	612,000,000	0
2	54,700,000	557,000,000
3	54,700,000	557,000,000
4	0	612,000,000

Note: Loadings and removals are rounded to three significant figures.

Table 19. Estimated Industry-Level BA Transport Water Pollutant Loadings and Removals by Regulatory Option

Regulatory Option	Estimated Total Industry Loadings (lb/Year)	Estimated Total Industry Removals (lb/Year)
Baseline	26,100,000	-
1	8,540,000	17,600,000
2	8,540,000	17,600,000
3	230,000	25,900,000
4	0	26,100,000

Note: Loadings and removals are rounded to three significant figures.

Table 20. Estimated Industry-level CRL Pollutant Loadings and Removals by Regulatory Option

Regulatory Option	Estimated Total Industry Loadings (lb/Year)	Estimated Total Industry Removals (lb/Year)
Baseline	67,700,000	-
1	67,200,000	496,000
2	67,200,000	496,000
3	67,200,000	496,000
4	67,200,000	496,000

Note: Loadings and removals are rounded to three significant figures.

Table 21. Estimated Industry-level Pollutant Loadings and Removals by Regulatory Option

Regulatory Option	Estimated Total Industry Loadings (lb/Year)	Estimated Total Industry Removals (lb/Year)
Baseline	706,000,000	-
1	688,000,000	18,000,000
2	130,000,000	575,000,000
3	122,000,000	584,000,000
4	67,200,000	639,000,000

Note: Loadings and removals are rounded to three significant figures.

7. Non-Water-Quality Environmental Impacts

Eliminating or reducing one form of pollution can aggravate other environmental problems, an effect often referred to as a cross-media impact. Sections 304(b) and 306 of the Clean Water Act (CWA) require the EPA to consider non-water-quality environmental impacts (NWQEIs), including energy impacts, associated with effluent limitations guidelines and standards (ELGs). Accordingly, EPA has considered the potential impacts of the proposed regulatory options considered for flue gas desulfurization (FGD) wastewater, bottom ash (BA) transport water, and combustion residual leachate (CRL) discharged from steam electric power plants on energy consumption (including fuel usage), air emissions, solid waste generation, and water use. Like the costs discussed in Section 5, the NWQEIs associated with the proposed regulatory options for this rulemaking are measured as incremental changes from baseline (i.e., the 2020 rule).

7.1 Energy Requirements

Steam electric power plants use energy (including fuel) when transporting ash and other solids on or off site, operating wastewater treatment systems, or operating ash handling systems. For those plants that are estimated to incur costs associated with the proposed rule, EPA considered whether there would be an associated incremental change in energy need compared to the baseline. That need varies depending on the regulatory option evaluated and the current operations of the plant. Therefore, as applicable, EPA estimated the change in annual energy consumption in megawatt hours (MWh) for equipment added to the plant systems or in consumed fuel (gallons) for transportation or equipment operation. Specifically, EPA estimated energy usage associated with operating equipment for the FGD wastewater treatment systems, BA handling systems, and CRL treatment systems considered for this proposed rule.

- To estimate changes in energy consumption associated with operating FGD wastewater treatment equipment, EPA developed relationships between FGD wastewater flow and energy usage for the following technologies: chemical precipitation, low residence time reduction (LRTR) biological treatment, and membrane filtration.
- To estimate energy usages for operating bottom ash (BA) handling systems, EPA developed relationships between electric generating unit (EGU) capacity and energy usage for the following technologies: mechanical drag system (MDS), remote mechanical drag system (rMDS) with a purge, and remote MDS with RO treatment of a slipstream to achieve complete recycle. EPA estimated electrical energy use from horsepower ratings of system equipment (e.g., pumps, mixers, silo unloading equipment) and energy usage data provided by wastewater treatment vendors. See the *Non-Water Quality Environmental Impacts for Revisions to the Steam Electric Effluent Limitations Guidelines and Standards* memorandum for additional details (U.S. EPA, 2023j).
- To estimate energy usages for operating CRL systems, EPA relied on the methodology developed for the chemical precipitation technology. EPA summed plant-specific energy usage estimates to calculate the net change in annual energy consumption for the regulatory options considered for the proposed rule; this information is presented in Table 22.

Energy usage also includes the fuel consumption associated with the changes in transportation. These changes include transportation needed to landfill solid waste and combustion residuals (*e.g.*, ash) at steam electric power plants to on-site or off-site landfills using open dump trucks and disposal of concentrated brine from the treatment of a remote MDS BA slipstream with an RO system to a centralized waste treatment (CWT) facility using a tanker truck. In general, EPA calculated fuel usage based on the estimated amount of time spent loading and unloading solid waste, combustion residuals, or concentrated brine into trucks and the fuel consumption during idling plus the estimated total transportation distance, number of trips required per year to dispose of the solid waste, combustion residuals, or concentrated brine, and fuel consumption. The frequency and distance of transport to a landfill 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 the *Non-Water Quality Environmental Impacts for Revisions to the Steam Electric Effluent Limitations Guidelines and Standards* memorandum, for more information on the specific calculations used to estimate fuel consumption associated with the transport and disposal of solid waste, combustion residuals, and concentrated brine (U.S. EPA, 2023j). Table 22 shows the net change in national annual fuel consumption associated with the proposed regulatory options compared to baseline (i.e., the 2020 rule).

Table 22. Net Change in Energy Use for the Regulatory Options Compared to Baseline

Non-Water Quality Impact	Net Change in Energy Use Associated with the ELG			
	Option 1	Option 2	Option 3	Option 4
Electrical energy usage (MWh)	38,000	126,000	139,000	151,000
Fuel (gallons per year)	53,000	122,000	622,000	639,000

7.2 Air Emissions Pollution

The proposed rule is expected to affect air pollution through three main mechanisms:

- Changes in power requirements by steam electric power plants to operate wastewater treatment and BA handling systems in compliance with the regulatory options.
- Changes to transportation-related emissions due to the trucking of combustion residual waste to landfills.
- Changes in the profile of electricity generation due to the regulatory options.

This section provides more detail on air emission changes associated with the first two mechanisms and presents the estimated net change in air emissions associated with all three. See EPA's *Benefit and Cost Analysis for Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* for further discussion of the third mechanism (U.S. EPA, 2023k).

Air pollution is generated when fossil fuels burn. Steam electric power plants also generate air emissions from operating vehicles such as dump trucks, tanker trucks, vacuum trucks, dust suppression water trucks, and earthmoving equipment, which all release criteria air pollutants and greenhouse gases. 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 (NO_x). 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 a wide range of domestic effects.[30] Conversely, decreasing energy use or less vehicle operation will result in decreased air pollution.

EPA calculated air emissions resulting from the change in power requirements[31] using year-explicit emission factors estimated by the Integrated Planning Model (IPM)[32] for CO_2, NO_x, and SO_2. The IPM output provides estimates of electricity generation and resulting emissions by plant and North American Electric Reliability Corporation (NERC) region. EPA used detailed outputs for the 2035 IPM run year to

[30] EPA did not specifically evaluate N_2O emissions as part of the NWQEI analysis. To avoid double-counting air emission estimates, EPA calculated only NO_x emissions, which would include N_2O emissions.

[31] Power requirements refers to the electricity needed to operate FGD wastewater treatment and/or BA handling technologies. Plants may generate this electricity on site or purchase the electricity from the grid.

[32] 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 estimated impact of environmental policies on the U.S. power sector.

estimated plant- and NERC-level emission factors (mass of pollutant emitted per kilowatt-hour of electricity generated) over the period of analysis. This run year represents steady-state conditions after rule implementation, when all plants are estimated to meet the revised BAT limits and pretreatment standards associated with each analyzed regulatory option.

EPA calculated NO_X, CO_2, and SO_2 emissions resulting from changes in power requirements based on the incremental auxiliary power electricity consumption, the pollutant- and year-specific emission factors, and the timing plants are assumed to install the compliance technology and start incurring additional electricity consumption.

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.[33]

EPA assumed that plants with CUR greater than 90.4 percent would draw additional electricity from the grid within the NERC region, instead of generating it on site. These plants will be using part of their 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, for these high-CUR plants, EPA used NERC-average emission factors instead of plant-specific emissions factors.

Because, for the proposed rule, EPA ran IPM for proposed Regulatory Option 3 only, EPA used IPM emission factors calculated for proposed Regulatory Option 3 to estimate changes in power requirements air emissions for all other proposed regulatory options.

To estimate air emissions associated with operation of transport vehicles, EPA used the MOVES3.0.3 model to generate air emission factors for NO_x, SO_2, CO_2, and CH_4. 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 (U.S. EPA, 2021). Table 23 lists the transportation emission factors for each air pollutant considered in the NWQEI analysis.

Table 23. MOVES3.0.3 Emission Rates for Model Year 2010 Diesel-Fueled, Long-Haul Trucks Operating in 2021

Roadway Type	NO_x (Tons/mi)	SO_2 (Tons/mi)	CO_2 (Tons/mi)	CH_4 (Tons/mi)
Highway	4.47E-06	6.84E-09	0.0020	6.18E-08
Local	5.88E-06	7.11E-09	0.0021	8.79E-08

Source: MOVES3.0.3 (database version “movesdb20220105”).

Vehicle types: Single and combination unit long-haul trucks, together.

Road types: Restricted access roads are "Highway" and unrestricted access are "Local"

EPA calculated the air emissions associated with the 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 and concentrated brine to a CWT.

EPA estimated the annual number of miles that dump trucks moving ash or wastewater treatment solids to on- or off-site landfills or tanker trucks transporting concentrated brine to CWTs would travel to comply with limitations associated with the regulatory options. See EPA’s memorandum *Non-Water Quality Environmental Impacts for Revisions to the Steam Electric Effluent Limitations Guidelines and*

[33] Emission factors are calculated as plant-level emissions divided by plant-level generation.

Standards for more information on the specific calculations used to estimate transport distance and number of trips per year (U.S. EPA, 2023j). The changes in national annual air emissions associated with auxiliary electricity and transportation for each of the regulatory options are shown in Table 24.

Table 24. Net Change in Industry-Level Air Emissions Associated with Power Requirements and Transportation by Regulatory Option

Non-Water Quality Impact	Air Emissions Associated with the ELG			
	Option 1	Option 2	Option 3	Option 4
NO_X (thousand tons/year)	0.02	0.065	0.081	0.085
SO_2 (thousand tons/year)	0.022	0.06	0.07	0.072
CO_2 (million metric tons/year)	0.03	0.12	0.134	0.145
CH_4 (tons/year)	0.0038	0.029	0.163	0.18

The modeled output from IPM predicts changes in electricity generation due to compliance costs attributable to the proposed options compared to baseline. These changes in electricity generation are, in turn, predicted to affect the amount of NOx, SO_2, and CO_2 emissions from steam electric power plants. A summary of the net change in annual air emissions associated with Option 3 for all three mechanisms are shown in Table 25. Similar to costs, the IPM from these options reflect the range of NWQEI associated with all four regulatory options. To provide some perspective on the estimated changes in annual air emissions, EPA compared the estimated change in air emissions to the net amount of air emissions generated in a year by all electric power plants throughout the U.S. For a detailed breakout of each of the three sources of air emission changes, see EPA's BCA Report (U.S. EPA, 2023k).

Table 25. Estimated Net Change in Industry-Level Air Emissions associated with Changes in Power Requirements, Transportation, and Electricity Generation for Proposed Option 3 Compared to Baseline

Non-Water Quality Impact	Change in Emissions – Proposed Option 3	2020 Emissions by Electric Power Generating Industry
CO_2 (million tons/year)	-11	1,650
NO_X (thousand tons/year)	-5.1	1,020
SO_2 (thousand tons/year)	-5.8	954

Source: eGRID.

7.3 Solid Waste Generation

Solid waste associated with the implementation of the proposed rule is based on the generation of residual treatment solids from the change in solids from membrane filtration versus LRTR, RO systems, and CP. EPA estimated the amount of solid waste generated from each technology for each applicable plant.

- EPA determined the FGD solids generated from membrane with encapsulation by multiplying an aggregate solids value by the plant specific optimized FGD flow rate (expressed in GPD). EPA then subtracted out the backwash dry solids generated from an LRTR system.

- EPA determined the BA solids (expressed in tons of brine solids per year) generated from RO systems by multiplying the purge flow (10 percent of the total BA system volume) by the average TSS concentration in BATW.[34]
- EPA determined the CRL solids generated from CP treatment by multiplying a flow-normalized dewatered sludge generation rate (expressed in tons per day of sludge per gallon per minute CRL flow) by the plant's CRL flow rate.

The net change in national solid waste production associated with the regulatory options is shown in Table 26.

Table 26. Net Change in Industry-Level Solid Waste by Regulatory Option

Non-Water Quality Impact	Solid Waste Generation with the ELG			
	Option 1	Option 2	Option 3	Option 4
Solids (tons/year)	236,000	1,220,000	1,240,000	1,340,000

7.4 Change in Water Use

Steam electric power plants generally use water for handling solid waste, including BA, and for operating wet FGD scrubbers. EPA estimated the plant-specific change in water intake, or process water use, associated with FGD wastewater treatment and BA handling for each evaluated technology options and baseline.

Plants expected to install a membrane filtration system for FGD wastewater treatment under the proposed regulatory options are expected to experience a decrease in water use compared to baseline because EPA anticipates they will reuse the membrane permeate in the FGD scrubber. EPA estimated the reduction in water use resulting from membrane filtration treatment compared to baseline is 70 percent of the optimized FGD flow for each plant expected to install membrane filtration under the regulatory option being evaluated.

EPA estimates that the proposed regulatory options evaluated will decrease water intake associated with BA handling as the proposed options require zero discharge of the BA purge. EPA used the purge volume for each plant, equivalent to 10 percent of the total rMDS volume as defined in Section 5.2.1, to estimate the decrease in water intake for each plant for BA.EPA does not expect the proposed regulatory options for CRL to have an impact on water use.

Table 27 presents the estimated incremental change in process water use for each regulatory option evaluated for the ELGs compared to baseline. The change in water use for each regulatory option is equivalent to the change in wastewater discharge. The industry-level process water use for membrane filtration is the same for all brine management options considered.

Table 27. Net Change in Industry-Level Process Water Use by Regulatory Option

Non-Water-Quality Impact	Change in Water Use with the Option			
	Option 1	Option 2	Option 3	Option 4
Water reduction (MGD)	4.47	9.79	11.8	12.4

[34] Similar to the 2020 rule methodology, EPA assumed plants would transfer RO brine to a centralized waste treatment (CWT) facility at an average distance of 40 miles.

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