**Environmental Compliance Strategy**

**Update for 2019**

Georgia Power Company

*January 2019*

**FORWARD-LOOKING STATEMENT CAUTIONARY NOTE**

Certain information contained in this report is forward-looking information based on current expectations and plans that involve risks and uncertainties. Forward-looking information includes, among other things, statements concerning environmental cost recovery and other rate actions, current and proposed environmental regulations and related compliance plans and estimated expenditures, projected emissions, population growth, planned construction projects, filings with the Georgia Public Service Commission (“PSC”), and Georgia Power’s expected renewable energy capacity. Georgia Power cautions that there are certain factors that can cause actual results to differ materially from the forward-looking information that has been provided. The reader is cautioned not to put undue reliance on this forward-looking information, which is not a guarantee of future performance and is subject to a number of uncertainties and other factors, many of which are outside the control of Georgia Power; accordingly, there can be no assurance that such suggested results will be realized. The following factors, in addition to those discussed in Georgia Power’s Annual Report on Form 10-K for the fiscal year ended December 31, 2017 and Quarterly Report on Form 10-Q for the quarter ended September 30, 2018, and subsequent securities filings, could cause actual results to differ materially from management expectations as suggested by such forward-looking information:the impact of recent and future federal and state regulatory changes, including environmental laws and regulations, and also changes in tax and other laws and regulations to which Georgia Power is subject, as well as changes in application of existing laws and regulations; the extent and timing of costs and liabilities to comply with federal and state laws, regulations, and legal requirements related to coal ash remediation, including amounts for required closure of certain ash impoundments; current and future litigation or regulatory investigations, proceedings, or inquiries; variations in demand for electricity; available sources and costs of fuels; the ability to control costs and avoid cost and schedule overruns during the development, construction and operation of facilities; the ability to construct facilities in accordance with the requirements of permits and licenses (including satisfaction of U.S. Nuclear Regulatory Commission requirements), to satisfy any environmental performance standards and the requirements of tax credits and other incentives, and to integrate facilities into the Southern Company system upon completion of construction; advances in technology; the ability to constrain operating and maintenance costs; state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and other cost recovery mechanisms; the direct or indirect effect on Georgia Power’s business resulting from cyber intrusion or physical attack and the threat of physical attacks; catastrophic events such as fires, earthquakes, explosions, floods, tornadoes, hurricanes and other storms, droughts, pandemic health events, or other similar occurrences; and the direct or indirect effects on Georgia Power’s business resulting from incidents affecting the U.S. electric grid or operation of generating resources. Georgia Power expressly disclaims any obligation to update any forward-looking information.

**ENVIRONMENTAL COMPLIANCE STRATEGY**

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**1.0 Georgia Power Environmental Compliance Strategy and Overview**

**Overview**

Georgia Power Company’s (“Georgia Power” or the “Company” or “GPC”) Environmental Compliance Strategy (“ECS”) includes a detailed overview of the applicable current and proposed environmental laws and regulations for its electric generation plants as well as a comprehensive strategy for compliance. The Company’s annual strategy development process considers plant-specific compliance options and evaluates those options based on: technology availability, cost, schedule, impact to plant operations, the environment, and surrounding communities. This approach provides the necessary flexibility to develop and refine Georgia Power’s environmental compliance strategy in today’s dynamic regulatory compliance environment. The resulting environmental compliance strategy combines the regulatory requirement assumptions with cost-effective and commercially available environmental control applications.

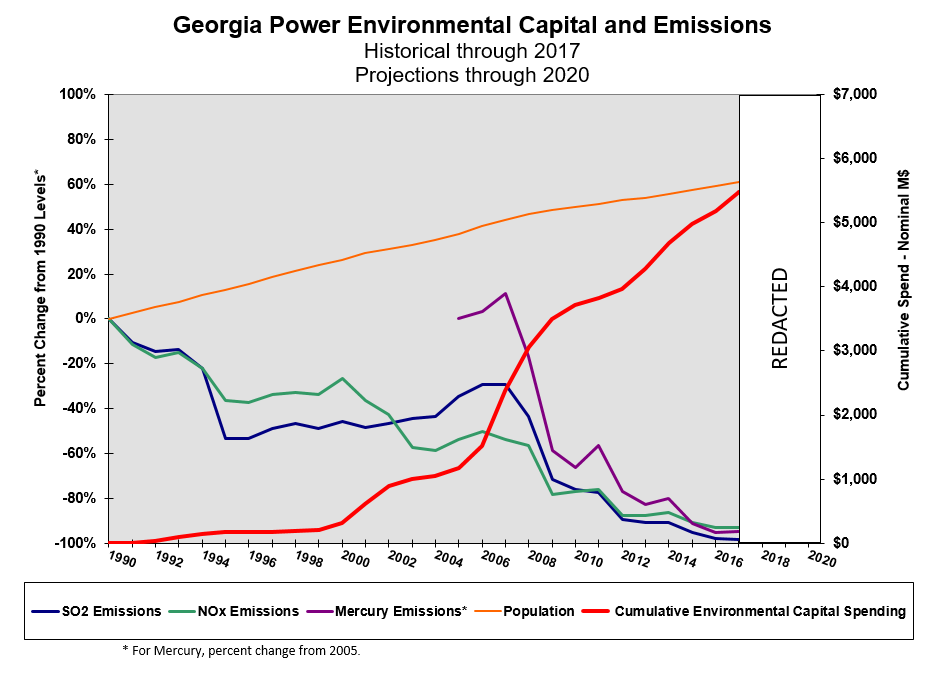
The information contained in this document includes an overview of applicable environmental laws and regulations, primarily focusing on the Clean Air Act (“CAA”), Clean Water Act (“CWA”), and Resource Conservation and Recovery Act (“RCRA”) (Section 2.0),  as well as a detailed description of the Company’s annual environmental strategy process (Section 3.0), and a comprehensive review of the Company’s current strategy for complying with these requirements (Section 4.0). The remainder of this section summarizes significant, applicable past environmental regulatory requirements and associated compliance strategies enacted by the Company, and provides an overview of present environmental rulings and requirements that have been incorporated into the Company’s ECS.

Georgia Power completed the initial Clean Air Act Amendments (“CAAA”) strategy in December 1990 and has implemented strategies pertaining to applicable environmental compliance or regulations in subsequent years. The Company’s compliance strategy, including potential unit retirement and replacement decisions, has been most directly impacted by: (i) the final requirements of any new or revised environmental statutes and regulations, (ii) the cost and availability of the environmental control technology, (iii) the cost, availability, and existing inventory of emissions allowances, and (iv) the Company’s fuel mix. Through 2017, Georgia Power has invested approximately $5.5 billion in capital projects to comply with applicable environmental regulations.

Georgia Power has installed numerous environmental controls and/or made associated expenditures necessary to comply with state and federal environmental requirements including Phase II of the 1990 CAA Acid Rain program; National Ambient Air Quality Standards (NAAQS), including the 1-hour and 8-hour ozone standards and the fine particulate matter (“PM”) standards; the regional nitrogen oxides (“NOX”) budget trading program; the Cross-State Air Pollution Rule (“CSAPR”); the Clean Air Visibility Rule (“CAVR”); the Georgia Multipollutant Rule and companion Sulfur Dioxide (“SO2”) Emissions Rule; the Mercury and Air Toxics Standards (“MATS”) Rule; the CWA Section 316(a) requirements for thermal discharges; CWA’s 1982 Steam Electric Effluent Limitations Guidelines (“ELGs”); Georgia Water Quality Standards; RCRA; and Georgia Rules for Solid Waste Management.

From 1990 to 2017, Georgia Power’s environmental compliance strategy and installation of environmental control equipment, to meet the requirements of state and federal regulations, has reduced NOX and SO2 emissions by approximately 93 and 99 percent, respectively (including Georgia Power’s share of Gaston 1-4). The installation and continued operation of baghouses, Selective Catalytic Reduction systems (“SCRs”), flue gas desulfurization (“FGDs”), and other MATS rule related controls have enabled the Company’s generating fleet to comply with new, more stringent regulations and have reduced Georgia Power’s 2017 mercury emissions by approximately 95 percent from 2005 levels (including Georgia Power’s share of Gaston 1-4). In addition, in making economic decisions in the best interest of customers, and without state or federal mandates, through 2017, Georgia Power has achieved carbon dioxide (“CO2”) emission reductions of more than 50 percent since 2007.

Figure 1-1summarizes historical and projected changes in emissions, population, and environmental capital costs (including Georgia Power’s share of Gaston 1-4). Even as Georgia’s population has grown, overall emissions have declined. The historical emissions for SO2 and NOx are shown back to 1990, while mercury emissions are shown back to 2005. Future emissions of SO2 and NOx are projected using the Aurora model.  Mercury projections are not available from Aurora because there is no allowance program or dispatch cost projected for mercury emissions.



**Figure 1‑1 Georgia Power Emissions and Environmental Capital Expenditures**

**(Actual Emissions Through 2017; Projected Estimates based on 2018 Energy Budget Projections)**

While investments in emission controls necessary to comply with state and federal clean air requirements remain a component of this ECS, the Company’s strategy also incorporates and focuses on actions to comply with land and water regulatory requirements.

Georgia Power has developed a strategy to comply with both the federal and state Coal Combustion Residuals (“CCR”) rules and the federal Steam Electric Effluent ELG Rule for its fossil-fuel fired plants. Compliance with these rules necessitates a multifaceted and highly coordinated approach that includes: the installation of dry ash handling equipment and wastewater treatment systems to eliminate coal ash transport water, completing ash pond closures, and wastewater treatment systems to replace the treatment function of the ash ponds for all waste streams, including low-volume wastewater, and FGD wastewater.

The Company has made significant progress toward effectuating this compliance strategy. This includes the design, construction, and operation of dry ash management systems and CCR wastewater management systems. In addition, considerable progress has been made toward compliance with state and federal rules regulating closure of ash ponds at the Company’s coal-fired plants. In response to these reguations, the Company is closing all 29 ash ponds located at 11 facilities across the state by removing the ash from 19 ponds located adjacent to lakes or rivers and closing the remaining 10 ponds in place using advanced engineering methods designed to enhance the protection of groundwater, improve closure stability, and minimize future maintenance of the unit. This includes progress on requirements by the Georgia Environmental Protection Division (EPD) to pursue required permits to be issued by EPD for each facility. Finally, the Company is evaluating FGD wastewater treatment technology performance across a variety of operational conditions to ensure the future technology investment can meet the required discharge limitations mandated under the ELG Rule.

The remainder of this document describes the applicable environmental regulations for which the Company must comply, the environmental strategy process, and details of the specific environmental compliance strategy the Company must undertake in order to comply with these new and existing regulations.

**1.1 Notable Regulatory-Related Events**

The following is a list of notable environmental regulatory events over the past several years.

* **January 2009** – Georgia Environmental Protection Division (“EPD”) finalizes the Georgia Rule for SO2 Emissions from Electric Utility Steam Generating Units (“Georgia SO2 Emissions Rule”).
* **October 2009** – U.S. Environmental Protection Agency (“EPA”) finalizes initial designations for 2006 24-hour fine particulate matter standard.
* **December 2009** – EPA issues an “endangerment finding” for motor vehicles which formally determines that six greenhouse gases (“GHGs”) taken in combination endanger both the public health and public welfare.
* **January 2010 –** EPA revises the Nitrogen Dioxide (“NO2”) NAAQS to include a new 1-hour standard at 100 parts per billion (“ppb”).
* **May 2010** – EPA releases Tailoring Rule that applies to stationary source air permitting for CO2 and other GHGs.
* **June 2010 –** EPA revises the SO2 NAAQS to include a new 1-hour standard at 75 ppb.
* **February 2011** – EPA finalizes Maximum Achievable Control Technology (“MACT”) rule for Industrial Boilers.
* **July 2011** – EPA releases final CSAPR.
* **December 2011** – Upon challenge by industry and states, D.C. Circuit Court stays CSAPR and orders EPA to continue administering Clean Air Interstate Rule (“CAIR”) pending judicial review. The decision is challenged at the U.S. Supreme Court.
* **December 2011** – EPA releases the final MATS Rule.
* **August 2012** – D.C. Circuit Court vacates CSAPR and remands the proceeding back to EPA, requiring the Agency to continue administering CAIR pending a lawful replacement.
* **August 2012** – EPA delays implementation of SO2 NAAQS until 2013.
* **December 2012** – EPA revises the fine particulate matter (“PM2.5”) NAAQS, lowering the 1997 annual standard to 12 micrograms per cubic meter (µg/m3).
* **December 2012** – EPA finalizes a revised Industrial Boiler MACT rule.
* **March 2013** – EPA signs final MATS reconsideration rule for new sources.
* **April 2013 –** Georgia EPD announces revisions to the Georgia Multipollutant Rule and Georgia SO2 Emissions Rule.
* **July 2013** – EPA finalizes initial designations for the 2010 SO2 NAAQS for certain areas of the country in the first of four rounds of designations.
* **April 2014** – The U.S. Supreme Court reverses the ruling vacating CSAPR and remands to the D.C. Circuit Court.
* **August 2014** – EPA publishes the final 316(b) rule for cooling water intakes.
* **June 2014** – U.S. Supreme Court vacates EPA’s GHG Tailoring Rule.
* **October 2014** – D.C. Circuit Court lifts the CSAPR stay and tolls compliance deadlines three years.
* **November 2014** – EPA signs the MATS Final Startup/Shutdown Reconsideration Rule.
* **January 2015** – EPA issues Industrial Boiler (“IB”) MACT Reconsideration proposal for major and area sources.
* **March 2015** – EPA finalizes initial designations for 2012 annual PM2.5 standard, but defers designations for certain areas of Georgia and Florida.
* **March 2015** - EPA enters into a Consent Decree to finalize designations for the 2010 1-hour SO2 NAAQS.
* **March 2015** – EPA publishes the final implementation rule for the 2008 ozone NAAQS.
* **April 2015** – EPA signs and releases the final CCR rule regulating CCR as a non-hazardous waste under subtitle D of RCRA.
* **May 2015** – EPA finalizes Startup Shutdown Malfunction (“SSM”) State Implementation Plan (“SIP”) call.
* **June 2015** – EPA issues final rule revising the definition of “Waters of the United States” (“WOTUS”).
* **June 2015** – U.S. Supreme Court rules EPA should have considered costs when deciding to regulate electric utilities under the MATS Rule and remands the case back to the D.C. Circuit Court.
* **July 2015** – D.C. Circuit Court remands CSAPR to EPA to reconsider Phase 2 SO2 emission budgets for several states, including Georgia.
* **August 2015** – EPA finalizes GHG standards for new, modified and reconstructed sources, and guidelines for existing sources, known as the Clean Power Plan (“CPP”). EPA also issues a proposed federal plan for implementing the existing source standards.
* **August 2015** – EPA finalizes SO2 Data Requirements Rule requiring states to characterize air quality, either through air quality monitoring or modeling, for areas around large sources of SO2.
* **August 2015** – EPA publishes revised federal water quality standards (“WQS”).
* **October 2015** – EPA revises the ozone NAAQS, lowering the 8-hour standard to 70 ppb.
* **October 2015** – Sixth Circuit Court issues a nationwide stay of the WOTUS rule, pending final decision of appropriate court jurisdiction.
* **November 2015** – EPA issues a revision to Steam Electric ELG Rule for wastewater discharges from new and existing coal-fired power plants.
* **November 2015** – EPA finalizes IB MACT Reconsideration for major sources.
* **December 2015** – EPA proposes supplemental appropriate and necessary finding for MATS. D.C. Circuit Court remands MATS Rule to EPA without vacatur to consider cost.
* **January 2016** – D.C. Circuit Court denies requests to stay the CPP, but grants an expedited schedule for hearing the case.
* **February 2016** – U.S. Supreme Court grants requests to stay the CPP.
* **February 2016** – EPA redesignates the Atlanta area to attainment of the 1997 annual PM2.5 NAAQS.
* **April 2016** – EPA finalizes MATS Technical Corrections rule.
* **April 2016** – EPA finalizes MATS supplemental “appropriate and necessary” finding addressing cost.
* **June 2016** – EPA proposes the Clean Energy Incentive Program (“CEIP”), a voluntary, early action program associated with the CPP.
* **July 2016 –** EPA completes the second round of designations for the 2010 SO2 NAAQS for additional areas of the country.
* **July 2016** – EPA revises the selenium aquatic life water quality criteria.
* **August 2016** – EPA publishes the final CCR Extension Rule for certain inactive CCR surface impoundments.
* **September 2016** – EPA finalizes CSAPR Update Rule to address the 2008 ozone NAAQS.
* **October 2016** – EPA proposes to revise its major source permitting rules after vacatur of Tailoring Rule to no longer require permits solely due to GHG emissions.
* **October 2016** – Georgia EPD recommends designations for the state of Georgia for the 2015 ozone NAAQS.
* **November 2016** – Georgia EPD submits revised SIP to EPA in response to the SSM SIP call.
* **November 2016** –Amendments to Georgia Solid Waste Management rules that include more stringent requirements for CCR surface impoundments and landfills (the “Georgia CCR Rule”) become effective.
* **December 2016** – The Water Infrastructure Improvements for the Nation (“WIIN”) Act was signed into law, allowing states to implement the CCR Rule through state permitting.
* **January 2017** –EPA revises CAVR to update state planning requirements for the 10-year period ending in 2028.
* **March 2017** – D.C. Circuit Court orders EPA to complete Risk and Technology Reviews (“RTR”) for certain MACT rules within 3 years, including the Combustion Turbine MACT.
* **April 2017** –EPA withdraws the following proposed rules: CPP Federal Plan, CPP Model Trading Rules, Amendment to the 111(d) Framework regulations, and CEIP.
* **April 2017** –EPA announces reconsideration and administrative stay of the ELG Rule.
* **June 2017** –EPA proposes a rule postponing the applicability dates for Best Available Technology (“BAT”) limits and pretreatment standards for the ELG Rule.
* **June 2017** – EPA redesignates Atlanta area to attainment of the 2008 ozone NAAQS.
* **July 2017** –EPA proposes to retain the current primary NO2 NAAQS, without revision.
* **July 2017** –Georgia EPD submits revised SIP to EPA to replace CAIR with CSAPR trading programs, including remanded Phase 2 SO2 budgets.
* **July 2017** –EPA and the U.S. Army Corps of Engineers propose a rule to repeal the 2015 WOTUS rule and reinstate the previous regulatory text.
* **August 2017** –EPA proposes the third round of designations for the 2010 SO2 NAAQS for additional areas of the country.
* **September 2017** –EPA finalizes postponement of ELG applicability dates for bottom ash transport water and FGD wastewater (“ELG Postponement Rule”); fly ash transport water applicability dates remained unchanged from 2015 ELG Rule.
* **October 2017** – EPA proposes to repeal the CPP.
* **November 2017** – EPA finalizes designations for the 2015 ozone NAAQS for most areas in the United States.
* **November 2017** – EPA files a Status Report with the D.C. Circuit Court indicating intent to issue a proposed CCR rulemaking by March 2018 to address provisions of the rule under reconsideration.
* **December 2017** – EPA issues an advanced notice of proposed rulemaking (“ANPRM”) to solicit information from the public as the Agency considers replacing the CPP.
* **January 2018** – EPA finalizes the third round of designations for the 2010 SO2 NAAQS.
* **February 2018** – Georgia Board of Natural Resources amends the Georgia CCR Rule to incorporate EPA’s amendments to the Federal CCR Rule and to add requirements for solid waste permits to undergo a regulatory review process.
* **March 2018** – EPA releases proposed Phase One Amendments to the CCR Rule to address four issues under litigation that the D.C. Circuit Court remanded back to EPA in 2016 as well as issues submitted to EPA through petitions for rule reconsideration.
* **March 2018** – The D.C. Circuit Court finds that compliance with CSAPR satisfies Best Available Retrofit Technology (“BART”) for regional haze planning.
* **March 2018** – The D.C. Circuit Court upholds startup work practice standards in IB MACT reconsideration.
* **April 2018** – EPA retains the primary NO2 NAAQS, without revision.
* **April 2018** – EPA finalizes nonattainment designations for seven counties in the Atlanta metropolitan area for the 2015 ozone NAAQS.
* **June 2018** – Georgia EPD revises SIP to remove legacy New Source Review (“NSR”) and Title V requirements applicable to the original 13 counties designated nonattainment for the revoked 1-hour ozone NAAQS.
* **June** **2018** – EPA proposes to retain the current primary SO2 NAAQS, without revision.
* **July 2018** – EPA publishes in the Federal Register the Phase One, Part One Amendments to the CCR Rule, entitled “Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals From Electric Utilities: Amendments to the National Minimum Criteria (Phase 1).”
* **August 2018** – The D.C. Circuit Court issues its decision on all remaining issues raised by litigants in CCR Rule litigation.
* **August 2018** – EPA proposes the Affordable Clean Energy (“ACE”) Rule, intended to replace the CPP.
* **September 2018** – EPA approves SIP revisions for Alabama and Georgia addressing interstate transport obligations with respect to the 2012 PM2.5 NAAQS.
* **November 2018** – Earliest applicability date for fly ash transport water pursuant to 2015 ELG Rule (and 2017 ELG Postponement Rule).
* **December 2018** – EPA releases proposal to revise GHG standards for new, modified and reconstructed sources.
* **December 2018** – EPA and the U.S. Army Corps of Engineers release a proposal redefining WOTUS.
* **December 2018** – EPA releases proposal to reconsider how costs were addressed in the supplemental appropriate and necessary finding and determine that no revision to the current MATS standards are warranted based on Residual Risk and Technology Review.

**1.2 Future Key Environmental Regulatory Events**

The following is a summary of upcoming key environmental developments and potential estimated dates.

* **Early 2019** – EPA anticipated to propose Phase Two of the amendments to the CCR Rule.
* **January 2019** – Court-ordered deadline for EPA to complete review of the SO2 NAAQS.
* **January 2019** – EPA anticipated to propose the RTR for combustion turbines.
* **March 2019** – EPA expected to finalize GHG standards for new, modified and reconstructed sources.
* **March 2019** – EPA expected to propose revised ELG Rule with revised limitations/standards for bottom ash transport water and FGD wastewater as well as new applicability dates.
* **June 2019 –** EPA anticipated to finalize Phase One, Part Two of the amendments to the CCR Rule.
* **December 2019** – EPA anticipated to finalize Phase Two amendments to the CCR Rule.
* **December 2019** – EPA expected to issue final ELG Rule with revised standards and applicability dates for bottom ash transport water and FGD wastewater based on the March 2019 proposal.
* **March 2020** – Court-ordered deadline for EPA to complete combustion turbine RTR.
* **April 2020** – Statutory deadline for EPA to conduct RTR for Electric Generating Unit (“EGUs”) regulated under MATS.
* **November 2020** – Earliest applicability date for ELG compliance for bottom ash transport water and FGD wastewater based on ELG Postponement Rule. This date could change based on revised final ELG Rule expected in December 2019.
* **Late 2020** – EPA has announced plans to complete review of ozone NAAQS.
* **December 2020 –** EPA deadline to complete the fourth and final round of designations for the 2010 SO2 NAAQS for the remaining areas of the country.
* **July 2021** – EPA deadline to submit regional haze SIPs for the second implementation period
* **Late 2022** – Anticipated date EPA expects to complete review of PM NAAQS.
* **December 2023** – Latest applicability date for ELG compliance based on ELG Postponement Rule. This date could change based on revised final ELG Rule expected in December 2019.

Section 2.0 of this document discusses these federal and state rules in more detail; Section 3.0 describes the process of developing the Environmental Compliance Strategy; and Section 4.0 discusses the results of the Company’s strategy and impacts of these environmental regulations to Georgia Power’s operations.

**2.0 Regulatory, Legislative, and Judicial Review**

Environmental compliance and regulation for Georgia Power Company is principally governed by the U.S. EPA, Georgia EPD, and other state and local authorities. The major environmental laws and regulations impacting Georgia Power, including any recent legislative, regulatory, or judicial developments, are detailed in this section.

**2.1 Major U.S. Environmental Laws**

**Clean Air Act**

The portions of the CAA and the 1990 CAAA that impact the electric utility industry most directly are:

* Title I, NAAQS
* Title III, Air Toxics
* Title IV, Acid Rain
* Title V, Permits

The core of the CAA is the NAAQS. The CAA requires that the EPA determine what level of six specific pollutants (ozone, PM, SO2, lead, carbon monoxide (“CO”), and NOx) in the ambient air is protective of human health with a margin of safety. Areas of the country where levels of these pollutants exceed the NAAQS are known as nonattainment areas. States must develop SIPs with control strategies designed to bring these areas into attainment. EPA is required to review the NAAQS every five years, update them if necessary and is authorized to issue regulations necessary to prevent emissions in one or more states from contributing to nonattainment in other states. EPA has implemented four programs for managing interstate impacts on nonattainment that have been applicable to Georgia Power units – the NOx Budget Trading Program (NOx SIP Call), CAIR, and CSAPR (as a replacement to CAIR) and the CSAPR Update Rule.

Title III of the CAAA requires regulation of listed Hazardous Air Pollutants (“HAPs”) and requires implementation of emission limits equivalent to the MACT for specific source categories, as determined by EPA. Many different MACT Rules affect Georgia Power, including, notably, the final MATS Rule. Once in place, MACT standards are to be reviewed by EPA every eight years.

The CAAA also added the Acid Rain Program (Title IV). This program requires reductions of SO2 and NOx emissions to reduce acid rain. The Acid Rain Program had the most immediate impact on Georgia Power and the electric utility industry following the 1990 amendments.

Title V of the CAAA added requirements for facilities to obtain federally-enforceable operating permits. The permits are meant to clearly lay out most of the applicable air quality-related regulations for affected facilities by compiling all applicable requirements into one document. Georgia Power’s Title V permits include both state and federal requirements and are issued by the Georgia EPD.

**Clean Water Act**

The CWA restores and maintains the chemical, physical and biological integrity of the WOTUS. Pursuant to the CWA, the National Pollutant Discharge Elimination System (“NPDES”) permit program was developed and implemented to regulate pollutant discharges to WOTUS. Authority to discharge under the CWA may be granted through a NPDES permit issued by EPA, or by a state that has been delegated such authority by EPA. The NPDES permit program is used as a means of achieving and enforcing technology-based and water quality-based effluent limitations. Georgia EPD has been delegated the authority to issue NPDES permits in Georgia.

EPA has established ELGs for the steam electric industry and other industrial source categories based on treatment technologies. These guidelines were promulgated in 1974, amended in 1982, and most recently updated in 2015. EPA is responsible for periodically reviewing and updating these ELGs, which serve as the basis of the technology-based permit limits that appear in individual NPDES wastewater discharge permits.

Section 316(b) of the CWA, which regulates cooling water intake structures, is implemented through NPDES permits. The Section 316(b) regulations are intended to protect fish and other aquatic species in the vicinity of utility cooling water intake structures. The focus of Section 316(b) is to ensure that the location, design, construction, operation, and capacity of cooling water intake structures reflect the best technology available to protect aquatic organisms from being impinged or entrained.

**Resource Conservation and Recovery Act**

This law governs the generation, transportation, treatment, storage and disposal of solid and hazardous waste. A major focus for electric utilities has been regulatory treatment of coal ash and other CCR, a solid waste, under RCRA and potential regulations affecting their management and disposal. In April 2015, EPA released a rule that regulates CCR as a non-hazardous waste under RCRA subtitle D.

The relevant programs and regulations derived from these laws are discussed in more detail in the following sections.

**Regulatory Review**

In early 2017, President Trump issued several Executive Orders pertaining to the review and potential repeal, replacement, or modification of federal regulations. On February 24, 2017, President Trump issued Executive Order (“EO”) 13777, “Enforcing the Regulatory Reform Agenda.” The EO is designed to reduce regulatory burdens agencies place on the American people and directs agencies to undertake several activities to further this goal. As a result of this EO, EPA published in the Federal Register a request for comment on regulations that may be appropriate for repeal, replacement, or modification.

On February 28, 2017, President Trump issued EO 13778, “Restoring the Rule of Law, Federalism, and Economic Growth by Reviewing the ‘Waters of the United States’ Rule”. The EO directs EPA and the U.S. Corps of Engineers to review the 2015 WOTUS Rule and propose a rule rescinding or revising the rule.

On March 28, 2017, President Trump issued EO 13783 “Promoting Energy Independence and Economic Growth.” This EO highlights the development of U.S. energy resources as a national interest. It instructs federal agencies to review all existing regulations, orders, guidance documents, policies, and any other similar agency actions that potentially burden U.S. energy resources. In this EO, a number of CO2-related EOs, memorandums, reports, and guidance are revoked or rescinded, and CO2-related regulations are identified as needing immediate agency review. As a result, in October 2017, EPA proposed a rule to repeal the CPP.

**2.2 Acid Rain Program**

For nearly 30 years, Georgia Power has been planning and implementing measures to comply with the requirements of the Acid Rain Program. Reductions in SO2 and NOX under the program were required in two phases – Phase I, beginning in 1995 and Phase II, beginning in 2000. Under the program, EPA issues emissions allowances for SO2 and requires that regulated units demonstrate that they have sufficient allowances to cover their SO2 emissions for each year. The regulations also set limitations on NOX emissions. This program allows plants to comply with the NOx limits individually, but also provides the option to comply through an averaging plan across multiple units.

**2.3 National Ambient Air Quality Standards**

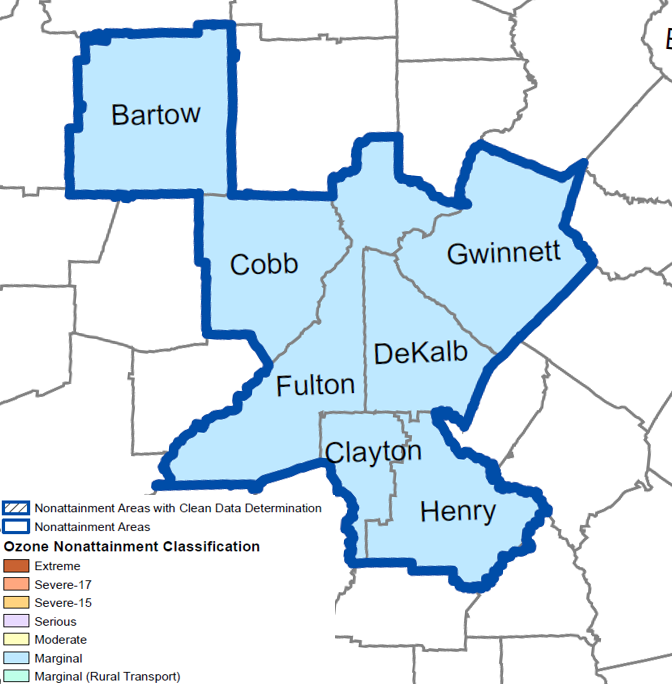
The CAA specifically requires EPA to review the primary and secondary NAAQS every five years and to revise them as necessary. These reviews have resulted in multiple, significant changes to the ozone and PM NAAQS, and the addition of short-term primary SO2 and NO2 NAAQS. Implementing these standards is generally a state responsibility; however, EPA has also issued rules, such as the NOx SIP Call, CAIR, and CSAPR, that deal with the transport of pollutants on a regional or multi-state basis to facilitate attainment with the NAAQS.

**Ozone**

Ozone is formed by a chemical reaction in the atmosphere between NOX and volatile organic compounds (“VOCs”). This reaction is driven by sunlight, and thus ozone formation is typically much more significant during the summer months. In 1979, EPA put into place a limit on 1-hour ozone concentrations of 120 ppb. Subsequently, the Agency replaced the 1-hour standard with an 8-hour standard of 80 ppb in 1997, which was lowered to 75 ppb in 2008.

For each ozone standard, portions of the Atlanta metropolitan area were designated as nonattainment during implementation. However, those areas have since been redesignated to attainment for the 1979, 1997, and 2008 standards.

In October 2015, EPA lowered the 8-hour primary standard from 75 to 70 ppb. In several actions in late 2017 and early 2018, EPA finalized designations for all areas in Georgia, including designating seven counties in the Atlanta metropolitan area as marginal nonattainment. This seven county nonattainment designation was in agreement with Georgia EPD’s recommendation. The graphic below (Fig. 2.3-1) shows the final nonattainment designations for the 2015 ozone NAAQS.



**Figure 2.3-1: Final EPA Non-Attainment Designations for the State of Georgia for the 2015 Ozone Standard**

**Particulate Matter**

In 1997, EPA revised the PM NAAQS to add fine particulate matter, i.e., PM2.5, as an indicator for the standard. The first PM2.5 standards were set at a level of 15 micrograms per cubic meter (µg/m3) on an annual average and 65 µg/m3 on a 24-hour average. In 2005, several areas within Georgia were designated as nonattainment for the PM2.5 annual standard, including the Atlanta, Floyd County, Macon, and Chattanooga areas. All areas in Georgia have since been redesignated to attainment of the 1997 PM2.5 annual standard.

In September 2006, EPA retained the annual standard but lowered the 24-hour standard from 65 µg/m3 to 35 µg/m3. In 2009, all areas in Georgia were designated as attainment for the more stringent 24-hour standard.

In December 2012, EPA lowered the annual standard for PM2.5 to 12 µg/m3. In April 2015, most areas in Georgia were designated as attainment for the more stringent annual standard and one year later, EPA designated the remaining areas as attainment for the 2012 standard.

**NO2 and SO2**

In 2010, EPA revised the NAAQS for NO2 and SO2 to establish 1-hour standards. The 1-hour NO2 ambient air quality standard was set at a level of 100 ppb, which became effective on April 12, 2010. EPA intended to initially focus on monitoring short-term peak concentrations which occur near major roadways, and the rule imposed new roadside monitoring requirements in urban areas. EPA’s initial designations based on available monitoring data classify the entire country as unclassifiable/attainment. None of the areas within Georgia are designated as nonattainment for the standard based on current ambient air quality monitoring data. On April 6, 2018, EPA retained the existing primary NO2 standards, without revision.

The 1-hour SO2­ ambient air quality standard was set at a level of 75 ppb, which became effective on August 23, 2010. In the 2010 SO2 NAAQS final rule, EPA outlined a plan to implement the standard through a combination of monitoring and modeling. Designations for this NAAQS were expected in June 2012 but EPA promulgated final “initial” nonattainment designations for 29 areas of the country in August 2013. No areas in Georgia were designated at this time.

EPA continued its implementation of the 2010 SO2 NAAQS with a proposed Data Requirements Rule released in April 2014 detailing the regulatory requirements for determining nonattainment areas and related requirements through modeling and/or monitoring.

In March 2015, EPA entered into a consent decree with environmental groups in the U.S. District Court for the Northern District of California settling claims that EPA failed to complete the area designation process by the statutory deadlines and agreeing to complete area designations in three stages. The consent decree codifies the timeline proposed in the Data Requirements Rule for designating most areas of the country with some areas requiring designation much more quickly than proposed in the Data Requirements Rule.

Later in March 2015, EPA informed 28 states, including Georgia, that, as a result of the consent decree, certain areas within their jurisdictions would be designated as either unclassifiable/attainment, nonattainment, or unclassifiable by July 2016. Juliette, GA, the area around Plant Scherer, was one such area identified based on plant-wide 2012 SO2 emissions. In July 2016, the EPA designated Juliette, GA as unclassified/attainment based on 2012-2014 modeling submitted to EPA by the Georgia EPD showing that SO2 emissions from Plant Scherer do not cause or contribute to any exceedances of the 1-hour SO2 NAAQS.

In August 2015, EPA finalized the Data Requirements Rule, which requires states to characterize air quality around sources that emit more than 2,000 tons per year of SO2 using either air quality modeling or monitoring. For sources that elected to characterize ambient air quality via modeling, modeling results were submitted by the states to EPA by January 2017. In January 2018, EPA finalized the third round of designations for the 2010 SO2 NAAQS. In this action, EPA designated all previously undesignated counties in Georgia as attainment/unclassifiable, except Floyd County, and Washington County, Alabama, where Plant Gaston is located, as unclassifiable. Other than an annual emissions review by the state agency, no further action is required for these areas. For sources that elected to characterize ambient air quality via monitoring, monitors were installed and operational by January 2017. Designations for these areas will be based on three years of monitoring data, from 2017 to 2019, and will be finalized by EPA in December 2020. Floyd County, which includes Plant Hammond, will be included in this final round of area designations due to monitoring data being collected for the International Paper facility in Rome. If any areas are designated nonattainment based on monitoring, attainment demonstrations will be required by August 2022.

In June 2018, EPA published a proposal to retain the primary SO2 standard without revision. EPA is under a court-ordered deadline to finalize the SO2 NAAQS review by January 28, 2019.

**2.4 Regional NOX SIP Call and Budget Trading Program**

In September 1998, EPA issued the final Regional NOX SIP Call Rule, which required 22 states and the District of Columbia (D.C.) to submit SIPs to address regional transport of the ozone precursor, NOX. The rule requires NOX emission reductions sufficient to meet specified emission budgets for each affected state.

The rule was challenged in the D.C. Circuit Court of Appeals, but was largely upheld by the Court. However, the Court vacated the rule for Georgia, Missouri, and Wisconsin. In April 2004, EPA reissued the NOX SIP Call as applied to the northern two-thirds of Georgia and the eastern half of Missouri, in accordance with the Court’s decision. Before issuance of the final rule, however, the two areas Georgia was determined to impact (Birmingham, Alabama and Memphis, Tennessee) came into attainment for the 1-hour ozone standard. On this basis, the Georgia Coalition for Sound Environmental Policy petitioned EPA to reconsider the final rule. EPA granted that petition and stayed the 2004 NOX SIP Call Rule as applied to Georgia. Following reconsideration in April 2008, EPA issued a final rule rescinding the NOX SIP Call as applied to Georgia. The NOx SIP Call has since been superseded by subsequent interstate transport rules, including CAIR and CSAPR.

**2.5 CAIR/CSAPR**

**Clean Air Interstate Rule**

EPA issued the final CAIR in March 2005. CAIR was designed to reduce SO2 and NOx emissions that contribute to nonattainment of the 1997 ozone and PM2.5 NAAQS in 28 eastern states, including Georgia and Alabama. It is based on a cap-and-trade regulatory scheme for NOx and SO2 that requires sources to hold allowances to cover their emissions. Georgia was subject to CAIR’s annual NOx and SO2 reductions under the 1997 PM2.5 NAAQS but not the CAIR ozone season NOx reduction requirements under the 1997 ozone NAAQS. Alabama, however, was subject to both the annual and ozone season NOx requirements under CAIR.

In July 2008, in response to petitions brought by certain states and regulated industries challenging particular aspects of CAIR, the D.C. Circuit Court issued a decision vacating CAIR in its entirety and remanding it to EPA for further action consistent with its opinion. In December 2008, however, the D.C. Circuit Court amended its July decision in response to the rehearing petitions and remanded CAIR to EPA without vacatur, thereby leaving CAIR compliance requirements in place while EPA developed a revised rule. The revised rule EPA developed was called CSAPR.

**Cross State Air Pollution Rule**

In July 2011 EPA released the final CSAPR as a replacement to CAIR. The final rule applied to 27 states, including Georgia and Alabama. Like CAIR, CSAPR established annual allowance trading programs for SO2 and NOx to reduce transport of fine particulate matter under the 1997 NAAQS and a separate ozone season NOx allowance trading program to reduce ground-level ozone under the 1997 standard. However, in a significant departure from past federal allowance trading programs, CSAPR only allowed for limited interstate trading. The rule divided states into two groups for purposes of SO2 allowance trading – Group 1 and Group 2. The rule prohibited trading across the two groups. In addition, like CAIR, CSAPR established SO2 and NOx emissions budgets for each affected state but CSAPR prohibited states from exceeding their state-wide budgets by more than a set percentage, referred to as the “variability limit.” In other words, CSAPR was not an unlimited cap and trade program like CAIR. The final rule was structured as a Federal Implementation Plan (“FIP”). States had the option of adopting a SIP, but not for initial compliance. CSAPR required substantial emission reductions by 2012 (Phase 1), just six months after issuance of the final rule, with another significant reduction required for many states, including Georgia, starting in 2014 (Phase 2).

In addition to stringent deadlines and requirements, the final CSAPR contained numerous and significant errors in the determination of state budgets. These underlying flaws prompted numerous states, industry organizations, and utilities to challenge the rule. Southern Company and its subsidiaries filed both a petition for administrative reconsideration and a petition for judicial review. On December 30, 2011, the D.C. Circuit Court stayed the rule pending resolution of the litigation and ordered EPA to continue administering CAIR in the interim.

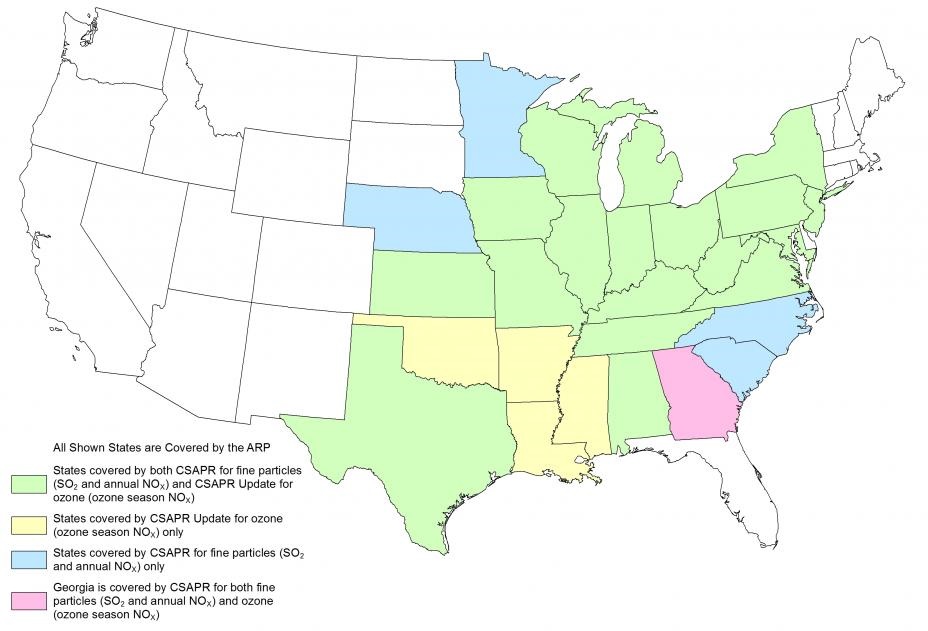
In August 2012, the D.C. Circuit Court vacated and remanded CSAPR and directed EPA to continue administering CAIR pending completion of a remand rulemaking to replace CSAPR with a valid rule. In April 2014, the U.S. Supreme Court reversed the D.C. Circuit Court vacatur of CSAPR and remanded the case back to the D.C. Circuit Court for further proceedings. In October 2014, the D.C. Circuit Court granted EPA's motion to lift the stay of CSAPR and toll the compliance deadlines by three years, so that CSAPR's Phase 1 emission budgets would apply in 2015 and Phase 2 emission budgets would apply in 2017 and subsequent years. This reinstatement of CSAPR replaced CAIR.

In July 2015, the D.C. Circuit Court issued its opinion, upon remand from the U.S. Supreme Court, invalidating EPA’s Phase 2 ozone season emissions budgets under CSAPR for 11 states, including Alabama, and required EPA to reconsider the Phase 2 annual SO2 emission budgets for 4 states, including Georgia and Alabama. The court's decision left the budgets in place and remanded the rule to EPA for further action consistent with the court's decision. However, subsequent revisions to CSAPR and actions by Alabama and Georgia to adopt CSAPR programs into their states SIPs have made these issues moot for Georgia Power facilities.

EPA has also updated and revised CSAPR recently to address interstate transport for downwind areas that have nonattainment issues associated with the 2008 ozone NAAQS. In July 2015, EPA issued a finding that 24 states, including Georgia, failed to submit an interstate transport SIP for the 2008 ozone NAAQS. This action started a 2-year clock for EPA to promulgate a FIP for each of these states unless, prior to EPA issuing the FIP, the state submits and EPA approves a SIP that meets the requirements of section 110 of the CAA.

On December 3, 2015, EPA proposed a rule, known as the CSAPR Update Rule, which would impose FIPs for 23 states, including Alabama, and establish or update the existing 2017 CSAPR NOx ozone season emissions budgets for EGUs.

In September 2016, EPA finalized the CSAPR Update Rule. The final rule imposed FIPs and significant reductions in ozone season NOx emissions allowances for 22 states, including Alabama. EPA determined that emissions from Georgia did not significantly contribute to downwind ozone nonattainment or maintenance problems related to the 2008 ozone NAAQS and therefore Georgia was not impacted by the Update Rule. The final rule updated the CSAPR NOx ozone-season emissions budgets for EGUs in affected states beginning in May 2017. The CSAPR Update Rule prevents power plants in Georgia from trading allowances with sources in other states. While several states, industry groups, and environmental groups have challenged the CSAPR Update Rule and/or filed requests with EPA to reconsider the rule, the new program remains in effect. Figure 2.5-1 shows the states that are covered by CSAPR and the CSAPR Update Rule.



**Figure 2.5-1 States Covered by the CSAPR and the CSAPR Update Rule**

**2.6 Mercury and Air Toxics Standards and New Source Performance Standards for Coal-Fired EGUs**

EPA issued the MATS Rule under Section 112 of the CAA. The MATS Rule, which was finalized in April 2012, is a technology-based command-and-control rule that regulates mercury, acid gases and certain metal emissions from coal- and oil-fired utility boilers. MATS establishes stringent emission limits based on MACT for hazardous air pollutants. While the rule contains limited emissions averaging provisions, in general, the limits must be met on a unit-by-unit basis.

EPA signed the proposed MATS Rule in March 2011. The proposed rule covered both new and existing coal- and oil-fired electric utility steam generating units and required each unit to meet stringent emission limits for mercury, PM (as a surrogate for certain metals), and acid gases. While all three categories of limits were very stringent, the particulate matter limit, in particular, included especially onerous compliance requirements. The proposed rule required units to not only comply with a standard numerical total particulate limit (filterable + condensable), but also required units to comply with unit-specific limits on filterable PM. These proposed requirements essentially removed all compliance margin built into existing controls without accounting for the natural variation in operation of a generating unit.

Numerous, significant concerns were raised over the stringency of the proposed emission limits and the ability to install the necessary control technologies by the compliance deadlines. Many industry, reliability organizations, and states filed comments on the rule suggesting that the results of this regulation could have a substantial impact on the reliability and affordability of electricity in the United States. In total, more than 150 industry comments were submitted on the proposed rule, and more than 27 states and 1 territory sought major changes or withdrawal of the rule.

In December 2011, EPA signed the final MATS Rule. The rule was published in the Federal Register on February 16, 2012 and became effective on April 16, 2012. The CAA specifies that MACT compliance for existing sources begins within three years after the effective date of the final rule with specific requirements for compliance extensions. Despite numerous requests by industry for additional compliance time due to the complex nature of the compliance requirements, EPA finalized the rule with a three-year compliance deadline for existing sources of April 16, 2015. In a change from the proposed rule, however, EPA stated in the final rule supporting documents that the one-year case-by-case extension from the state permitting authority should be “broadly available” for units installing controls as well as for units that are in the process of being replaced or retired but that are necessary for maintaining system reliability. Approximately 142 GW of coal-fired capacity nationwide, including all Georgia Power units subject to MATS, applied for and were granted one-year compliance extensions.

While many provisions, such as the mercury and acid gas limits, were largely unchanged from the proposed rule, EPA did make key changes in the PM requirements that ultimately led to changes in the compliance strategy for Georgia Power. In the final rule, EPA changed the form of the PM limit from the more uncertain total PM to the more commonly and reliably measured filterable PM and eliminated the requirement to have unit-specific operating limits.

On April 16, 2012, Southern Company, as well as Utility Air Regulatory Group (“UARG”), filed a petition for reconsideration of certain aspects of the final rule. UARG also filed a petition for judicial review with the D.C. Circuit Court. On April 15, 2014, the D.C. Circuit Court issued its opinion, denying all petitioners’ challenges to the MATS Rule that were before the court. After several petitions were submitted by state and industry groups, on November 25, 2014, the U.S. Supreme Court granted writ of certiorari on the limited question of whether EPA unreasonably refused to consider cost in determining whether it was appropriate and necessary to regulate HAPs from coal- and oil-fired electric generating units.

On June 29, 2015, the U.S. Supreme Court issued its decision, finding that EPA interpreted the CAA unreasonably when it deemed cost irrelevant to the decision of whether regulation of power plants under section 112 is “appropriate and necessary,” and reversed and remanded the lower court’s decision. While the U.S. Supreme Court directed that EPA must consider cost before deciding whether regulation of power plants is “appropriate and necessary,” the Court left it up to EPA to decide how to account for cost and remanded the case to the D.C. Circuit Court for further proceedings. On December 1, 2015, EPA issued its proposed finding that, after considering cost, it remains appropriate and necessary to regulate HAPs from EGUs under Section 112. In light of EPA’s proposal, the D.C. Circuit Court issued an order on December 15, 2015 remanding the MATS Rule to EPA to finish the pending rulemaking, without vacatur of the rule. As a result, the MATS Rule remained in effect with no change to the compliance date or requirements.

In April 2016, EPA finalized the “Supplemental Finding” after consideration of cost, which was challenged at the D.C. Circuit Court by numerous parties, including states, trade associations, and coal and utility companies, including Southern Company and its operating companies. The pending legal challenge is being held in abeyance, however, while EPA, under the new Administration, evaluates whether to maintain, modify, or reconsider the MATS Rule.

On December 27, 2018, EPA Acting Administrator Andrew Wheeler signed a proposed rule titled, “National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units -- Reconsideration of Supplemental Finding and Residual Risk and Technology Review reconsideration.” EPA is proposing to correct what it identifies as flaws in the cost analyses conducted in the 2016 Supplemental Finding (i.e., the cost/benefit analysis EPA used to determine that it is appropriate and necessary to regulate), now relying on a comparison of direct benefits of HAP controls to costs of compliance, concluding that it is not appropriate and necessary to regulate HAP emissions from EGUs. However, EPA concludes that, in light of a 2008 D.C. Circuit Court opinion in *New Jersey v. EPA*, finalizing this determination will not remove coal- and oil-fired EGUs from sources listed and regulated under Section 112, nor will it affect the MATS standards. Nevertheless, EPA is taking comment on whether, in light of the revised finding, EPA would have the authority and/or obligation to rescind MATS or remove EGUs from the list of sources regulated under Section 112. Pending resolution of these issues, the MATS Rule remains in effect with no change to the requirements for compliance.

Since MATS was finalized in 2012, EPA has proposed and finalized several revisions to the rule. On November 30, 2012, EPA proposed a reconsideration of certain new source provisions and for startup and shutdown issues for existing sources. EPA completed its reconsideration rulemaking for new sources in April 2013, but deferred acting on the existing source reconsideration. On November 19, 2014, EPA issued the Final Reconsideration Rule on Startup/Shutdown Issues, finalizing an alternative startup definition, including additional work practice standards, monitoring, and reporting requirements, and making numerous other significant changes to the rule. On December 19, 2014, EPA signed a proposed MATS Technical Corrections Rule, which proposed to correct certain ambiguous and unworkable compliance requirements, both from the Final 2012 Rule and the 2014 Startup/Shutdown Reconsideration Rule. The Final MATS Technical Corrections Rule became effective on April 6, 2016. In addition, EPA is expected to make additional revisions to electronic reporting requirements for MATS in the future.

EPA is required to conduct a Residual RTR of the MATS Rule within eight years after the original standards are finalized (i.e., by 2020). This review must account for technology developments and address residual health risk for standards set under Section 112, such as MATS. As noted above, on December 27, 2018, EPA Acting Administrator Andrew Wheeler signed a proposed rule that, in addition to reconsidering the Supplemental Finding, includes the required RTR. Based on EPA’s residual risk assessment, the agency proposes to conclude that the remaining risk from HAP emissions from EGUs is acceptable and that the current standards are adequate. Furthermore, EPA concludes under the technology review that no new developments in HAP emission controls warrant more stringent standards.

The CAA also requires EPA to review and update as necessary its New Source Performance Standards (“NSPS”) under the Act, which are designed to facilitate compliance with the NAAQS. The impact of these rules is usually limited to new power plants, but NSPS can also impact existing plants under certain circumstances. In conjunction with the MATS rulemaking, EPA released final revisions to the NSPS for Electric Utility Steam Generating Units in December 2011. The revisions included more stringent limits for NOx and SO2 for new coal-fired power plants, as well as some minor revisions affecting compliance options for both existing and new plants subject to the NSPS rule.

**2.7 Combustion Turbine NSPS and MACT**

Simple-cycle and combined-cycle combustion turbines can be subject to existing requirements under MACT and/or NSPS rules, reviews of which are pending. In August 2012, EPA proposed revisions to the NSPS for Stationary Combustion Turbines. While the proposed revisions make few changes to the numerical NOx and SO2 emission limits, EPA’s proposal would make some key changes to certain compliance demonstrations. For example, while the rule typically only applies to new power plants, EPA proposed to drastically change the way that projects at an existing unit must be evaluated to determine whether the unit has been “reconstructed”, thus triggering applicability of the rule. In June 2017, EPA officially withdrew the proposed revisions to the NSPS for Stationary Combustion Turbines.

EPA is also under court order from the D.C. Circuit Court to finalize its review of the combustion turbine MACT requirements by March 2020. The Court agreed with environmental groups that EPA should be placed on a schedule to finalize the RTR for this rule that is overdue. EPA has not yet issued a proposed rule to respond to this court order, but is expected to do so by February 2019.

**2.8 Industrial Boiler MACT**

In February 2004, EPA finalized the Industrial Boiler (“IB”) MACT rule to impose limits on HAPs from industrial boilers, including biomass-fired boilers used for electricity generation. Compliance with the final rule was scheduled to begin in September 2007; however, in response to challenges to the final rule, the D.C. Circuit Court vacated the rule in its entirety in July 2007.

In response to the court’s ruling, EPA began development of a new IB MACT, establishing emissions limits for different subcategories of boilers, including natural gas-fired boilers, oil-fired boilers, biomass stoker boilers, and biomass fluidized bed boilers among others. EPA issued a final rule in February 2011, but it has since reconsidered and revised that rule several times. The limits in the new IB MACT are much more stringent than the IB MACT that was vacated in 2007.

The first of EPA’s reconsideration rules was published in the Federal Register in January 2013, with compliance for existing sources required in January 2016 and compliance for new sources required upon startup. While the final rule published in January 2013 is less stringent than the 2011 rule, continued concerns over the stringency of the emission limits for many types of boilers led EPA to propose and finalize additional revisions in 2015 and 2016.

This series of IB MACT rules has been challenged in multiple lawsuits in the D.C. Circuit Court of Appeals. The D.C. Circuit Court addressed most of the challengers’ claims in a decision issued in July 2016, in which the court denied most, but granted a few, of the challenges raised. However, even where the court agreed with the challengers’ arguments, the court only remanded a portion of the rules and allowed the rules to remain in place while EPA addresses the identified concerns. In March 2018, the D.C. Circuit Court issued its opinion upholding the “startup definition 2” work practice standard and remanding the CO standard to EPA for further proceedings to justify its use as a surrogate for organic HAPs.

**2.9 Clean Air Visibility Rule**

CAVR (also known as the Regional Haze Rule) was finalized in July 2005. The goal of this rule is to restore natural visibility conditions in specified “Class 1” areas (primarily national parks and wilderness areas) by 2064. The rule involves: (1) the application of BART to certain sources built between 1962 and 1977, and (2) the application of any additional emissions reductions which may be deemed necessary for each designated area to achieve reasonable progress toward the natural conditions goal by 2018, the end of the first planning period. Thereafter, for each 10-year planning period, additional emissions reductions will be required to continue to demonstrate reasonable progress in each area. For power plants, states may determine that CSAPR satisfies BART requirements for SO2 and NOx.

In March 2018, the D.C. Circuit Court upheld EPA’s determination that compliance with CSAPR would satisfy BART.

In January 2017, EPA finalized revisions to the second planning period under the regional haze rule, covering the period 2019-2028. These include extension of the deadline for the next SIP submittal from July 2018 to July 2021, and increased requirements for state consultations with Federal Land Managers.

**2.10 Georgia Multipollutant Rule and Georgia SO2 Emissions Rule**

In response to federal environmental rules as well as state-specific objectives, the state of Georgia implemented a set of state rules governing emissions from coal-fired power plants. The Georgia Multipollutant Rule was finalized in June 2007, while the Georgia SO2 Emissions Rule was finalized in January 2009. Both rules require the installation and operation of certain emission controls on all of the larger coal-fired electric generating units in the state by specific dates.

The Georgia Multipollutant Rule was designed to reduce emissions of mercury, SO2, and NOx state-wide by requiring installation of specified control technologies at each affected unit by specific dates originally set between December 31, 2008, and June 1, 2015. This rule requires the installation and operation of SCRs for NOX reduction and FGDs for SO2 reduction on the majority of Georgia Power’s coal-fired units. The rule also requires installation and operation of baghouses with sorbent injection at Plant Scherer for mercury control.

The Georgia SO2 Emissions Rule was designed to be a companion rule to the Georgia Multipollutant Rule. The rule requires reduction of SO2 emissions by 95% from all units required to install FGDs under the Georgia Multipollutant Rule, except Plant Yates Unit 1 where a 90% reduction was required. The rule required compliance beginning in January 2010 for units with FGDs in operation, and requires reductions from the remaining units at dates that align with or are close to the Multipollutant Rule compliance dates.

In June 2011, revisions to both the Georgia Multipollutant Rule and Georgia SO2 Emissions Rule were approved by the Georgia Department of Natural Resources. These revisions moved up the FGD and SCR compliance dates and also allowed for additional time to install controls in an attempt to streamline the compliance deadlines in the state rules with the new MATS Rule, which was not yet final at the time. This change allowed the Company to consider the MATS compliance requirements in the design and construction process, as well as in the decision regarding whether to proceed with controls at the affected units.

In April 2013, additional revisions to both the Georgia Multipollutant Rule and the Georgia SO2 Emissions Rule were approved by the Georgia Department of Natural Resources. These revisions aligned some of the compliance dates in the state rules with the MATS rule compliance dates.

The control technology for each unit to meet the Multipollutant Rule requirements were outlined in Table 2.10-1 of the 2016 Update to the ECS, found in Docket No. 40161. These control technologies are installed and operational, with ongoing maintenance requirements for continued reliable operation.

**2.11 Startup, Shutdown and Malfunction SIP Call**

In February 2013, EPA signed a proposed SIP Call that would require 36 states (including all of the states in EPA’s Region 4) to revise their SSM rules because they purportedly are inconsistent with the CAA and EPA policy. The Sierra Club petitioned EPA to take this action, primarily based on the arguments that such provisions allow emissions that could cause or contribute to violations of ambient air quality standards, and that they interfere with or preclude enforcement by agencies and citizens.

In June 2014, EPA entered into an agreement with environmental petitioners that required EPA to issue a supplemental proposed action on Sierra Club’s petition in September 2014, and to take final action in May 2015. On September 5, 2014, EPA signed a supplemental proposal, addressing affirmative defenses for excess emissions from malfunctions. EPA’s supplemental proposal only addressed the issue of affirmative defense provisions for excess emissions during periods of malfunctions, and did not modify the previous proposal in any other way. Georgia was identified by EPA as having such affirmative defense provisions in its SIP. On May 22, 2015, EPA took final action on its findings of “substantial inadequacy” of the SIPs of 36 states, issuing a final SIP Call requiring affected states to remove exemptions for excess emissions that occur during periods of startup, shutdown, and malfunction. Affected states were required to submit revised SIPs to EPA by November 22, 2016. Petitions for judicial review by multiple environmental groups, industry groups, states, and individual companies, including Southern Company, Georgia Power, and the other operating companies, were filed on August 11, 2015.

In response to the SIP Call, the state of Georgia developed new requirements for work practice standards for emissions that occur during periods of startup, shutdown, and malfunction in 2016. While the new state rule is final, it does not take effect unless it is approved by EPA. On November 17, 2016, Georgia EPD submitted the new state rule to EPA for approval as a revision to its SIP to address the SIP Call. To date, EP has not acted on that SIP submittal.

In April 2017, EPA requested that judicial review of the final SIP Call be placed on hold to allow EPA time to review the rule, and the Court granted the request in April 2017. At this time, the agency has not taken any action on proposed SIP revisions that have been submitted.

**2.12 GHG Policies and Emissions**

**GHG and Renewable/Clean Energy Legislation**

Over the past decade, the U.S. Congress considered many proposals to reduce GHG emissions and mandate renewable or clean energy. The proposals took many forms, for example: a cap and trade program, carbon tax, and renewable/clean energy standards. Several bills were brought to the legislative floor which include the “Waxman-Markey” cap and trade bill, the “Sanders-Boxer” carbon tax bill, and the Bingaman “Clean Energy Standard Act” that attempted to set a clean energy standard.

In recent years, there have been federal-level Congressional efforts to discuss and introduce carbon-related legislation. The most prominent efforts related to federal carbon tax  proposals in 2018 included: H.R. 7173 (Representative Deutch), S. 3791 (Senator Coons), S. 2368 (Senator Whitehouse), and H.R. 6463 (Representative Curbelo). Each of these proposals impose an economy-wide carbon tax that includes a border carbon adjustment fee and establishes an initial price on carbon ($/ton CO2) with varying degrees of escalation each year until the proposal’s specific national reduction targets are achieved. H.R. 7173 and S. 3791 aim to take effect in 2019, start at $15/ton, and increase $10 each year. S. 2368 aims to take effect in 2019 at $50/ton, and increase 2% a year plus inflation. H.R. 6463 aims to take effect in 2020, start at $24/ton, and increase 2% a year plus inflation.

To date, Congress has declined to pass legislation to reduce GHG emissions or mandate renewable energy.

**Global Climate Change – International**

In 1992, countries negotiated an international treaty, the United Nations Framework Convention on Climate Change (“UNFCCC” or “Convention”) to consider addressing climate change. To date, 195 countries (“Parties to the Convention”), including the United States, have ratified the Convention. The first Conference of Parties (“COP”) 1 was held in 1995, which resulted in a “mandate” to negotiate a protocol to the Convention. In 1997, the Parties to the Convention negotiated the Kyoto Protocol which sought to bind industrialized counties to commitments to reduce emissions of greenhouse gases. The Kyoto Protocol’s first commitment period started in 2008 and ended in 2012. The second commitment period began in 2013 and will end in 2020. To date, 192 countries, not including the United States, have ratified the Kyoto Protocol.

Since 2005, the Convention has established various “working groups” to address key issues and negotiate future climate-related international agreements. Such key issues include future commitments under the Kyoto Protocol, long-term cooperative action, and a “legally binding” post-2020 emission reduction program. The Working Groups meet periodically throughout the year and, along with the formal subsidiary bodies to the Convention, again at the annual COP and a Meeting of the Parties to the Kyoto Protocol (“CMP”). The COP is the supreme decision-making body of the Convention, which reviews the implementation of the Convention and other legal instruments. The CMP reviews the implementation of the Kyoto Protocol. To date, there have been 14 CMPs and 24 COPs.

On March 31, 2015, the United States submitted to the UNFCCC its economy-wide target to cut net GHG emissions. The submission, referred to as an intended nationally determined contribution, is a formal statement of the United States target to reduce emissions 26-28% below 2005 levels by 2025, and to make best efforts to reduce by 28%.

COP 21 took place in late 2015 in Paris, France. The result of COP 21 was the adoption of the Paris Agreement, which establishes a universal framework for addressing GHG emissions based on nationally determined contributions. It also sets in place a process for increasing those commitments every five years.

On September 3, 2016, the U.S. Administration “accepted” the Paris Agreement via executive agreement. On November 4, 2016, the Paris Agreement entered into force due to at least 55 countries representing at least 55% of the world’s GHG emissions formally joining the agreement.

On June 1, 2017, President Trump announced that the U.S. will withdraw from the Paris Agreement and begin negotiations to re-enter the Paris Agreement under new terms or negotiate an entirely new agreement.

COP 24 took place in December 2018 in Katowice, Poland. The result was a set of implementing guidelines for the 2015 Paris Agreement. A key component of the agreement lays out a detailed transparency framework which sets out how countries will provide information about national climate actions plans, including reduction, mitigation, and adaptation measures. An agreement was also reached on how to uniformly count GHG emissions. COP 25 will take place in Chile in December 2019.

**Greenhouse Gas Regulations - Background**

In April 2007, the U.S. Supreme Court ruled that EPA has authority under the CAA to regulate GHG emissions from new motor vehicles and that EPA must decide whether these emissions endanger public health and welfare. In December 2009, EPA published a final determination, which became effective in January 2010, that certain GHG emissions from new motor vehicles endanger public health and welfare. In April 2010, EPA issued a final rule regulating GHG emissions from new motor vehicles under the CAA. EPA took the position that once this rule went into effect in January 2011, CO2 and other GHGs became regulated pollutants under the prevention of significant deterioration (“PSD”) preconstruction permit program and the Title V operating permit program, which both apply to power plants. As a result, the construction of new facilities or the major modification of existing facilities could trigger the requirement for a PSD permit and the installation of the Best Available Control Technology (“BACT”) for CO2 and other GHGs.

In May 2010, EPA issued a final rule, referred to as the Tailoring Rule, governing how these programs would be applied to stationary sources, including power plants. In accordance with the Tailoring Rule, as of January 2, 2011, new and modified sources that have GHG emissions over the thresholds (100,000 tons per year (“tpy”) for new sources and increases over 75,000 tpy for existing sources) were required to go through PSD permitting including installation of BACT for CO2 and other GHGs.

These GHG regulations were litigated. In December 2010, the D.C. Circuit Court denied the motions for a stay of EPA's GHG rules, which had been filed by Texas and a number of industry petitioners. In June 2012, the Court upheld these EPA rules. All petitions to review were dismissed or denied.

In October 2013, the U.S. Supreme Court agreed to review one narrow, but important, issue: “whether EPA permissibly determined that its regulation of greenhouse gas emissions from new motor vehicles triggered permitting requirements under the Clean Air Act for stationary sources that emit greenhouse gases.”

In June 2014, the U.S. Supreme Court ruled that:

• EPA cannot require PSD or Title V permitting solely on the basis of GHG emissions.

• EPA cannot “tailor” the CAA’s unambiguous permitting thresholds.

• For large facilities that are already required to apply for PSD permits because of conventional air emissions (“anyway sources”), EPA can require those applicants to undertake a BACT analysis if they emit GHGs above a de minimis amount.

• Even for those facilities that must obtain PSD permits anyway and become subject to GHG BACT, the Court reminded EPA of the limits on its authority. For example, the BACT analysis must take into account energy, economic, and environmental considerations, and may not require redesign of a facility or even require reductions in demand for electricity from the grid.

In October 2016, EPA released a proposed rule to revise PSD and Title V GHG permitting regulations and establishing a significant emission rate (“SER”). The revisions to the current permitting regulatory text were administrative in nature; however, the proposal also established a de minimis permitting threshold of SER at 75,000 tons per year of CO2 equivalent. This SER level would set the floor at which a GHG BACT analysis would not have to be applied. EPA’s Fall 2018 Unified Agenda states EPA expects to take action on this proposal in the future but there is no timeline listed for expected final action.

**Biogenic CO2 Emissions**

On July 20, 2011 EPA published a final rule that deferred GHG permitting requirements for CO2 emissions from biomass-fired and other biogenic sources under the PSD and Title V programs for three years. Groups challenged EPA’s three-year deferral, and on July 12, 2013, the D.C. Circuit Court vacated the three-year deferral. While the Court withheld the issuance of its “mandate,” and the decision did not become final, the three-year deferral rule expired by its own terms in July 2014.

In September 2011, EPA released a draft accounting framework for biogenic CO2 emissions from stationary sources, and in November 2014, EPA released a second draft for review by the EPA Science Advisory Board (“SAB”) and for public comment. The SAB continues to review EPA's second draft.

In April 2018, then EPA Administrator Scott Pruitt issued a statement of policy that future regulatory actions will treat biogenic CO2 emissions resulting from the combustion of biomass from managed forests at stationary sources for energy production as carbon neutral.

**CO**2 **Regulation – Performance Standards**

In June 2013, President Obama announced his Climate Action Plan designed to reduce emissions of GHGs and take additional steps to mitigate and adapt to climate change. At the same time, President Obama released a White House memorandum on “Power Sector Carbon Pollution Standards” that directed EPA to propose and finalize standards, regulations, or guidelines for new, modified, reconstructed, and existing fossil-fired electric generating units.

Consistent with the Climate Action Plan and subsequent memorandum, EPA issued a new source proposal in September 2013 (Standards of Performance for Greenhouse Gas Emissions from New Stationary Source: Electric Utility Generating Units), a modified and reconstructed source proposal in June 2014 (Carbon Pollution Standards for Modified and Reconstructed Stationary Sources: Electric Utility Generating Units), and an existing source emission guidelines proposal (Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units or Clean Power Plan) in June 2014. Southern Company submitted comments on all three proposals.

On October 23, 2015, EPA’s final new, modified, and reconstructed source standards for CO2 emissions under section 111(b) of the CAA were published in the Federal Register. In the final new source rule, EPA established separate standards for coal (1,400 lbs of CO2/MWh) and natural gas combustion turbines (1,000 lbsofCO2/MWh). EPA’s standard for new coal units requires the implementation of partial carbon capture and sequestration (CCS).

Also, on October 23, 2015, EPA’s final guidelines for CO2 emissions from existing sources under 111(d) of the CAA were published in the Federal Register. EPA’s final emission guidelines for existing sources, known as the Clean Power Plan (CPP), established binding national performance rates for two sub-categories: (1) fossil steam and Integrated Gasification Combined Cycle (“IGCC”) units and (2) Natural Gas Combined Cycle (“NGCC”) units. EPA also finalized alternative state-specific rate- and mass-based goals with an interim compliance period of 2022 – 2029 and a final compliance date of 2030. EPA’s performance rates and alternative state goals were based on three “building blocks”: (1) coal unit heat rate improvements; (2) operating NGCCs at higher capacity factors to displace generation from coal-fired units; and (3) increasing renewable energy generation to displace generation from fossil-fired units. In accordance with EPA’s emission guidelines, State Plans, which consider EPA’s guidelines, were due to EPA by September 2016 with a 2-year extension possible.

Lastly, on October 23, 2015, EPA’s proposed Federal Plan requirements, Model Trading Rules, and amendments to the 111(d) implementing regulations were published in the Federal Register. These proposals provided the framework for a Federal Plan that would be issued to states that did not submit a satisfactory State Plan to EPA.

Both the final new source standards and the CPP were subject to numerous petitions for review filed in the U.S. Court of Appeals for the D.C. Circuit by states, industry and trade associations, and individual companies, including Georgia Power and the other Southern Company operating companies. Petitioners challenging the final CPP filed motions for stay of the final rule pending resolution of the litigation. In January 2016, the D.C. Circuit Court denied petitioners’ requests to stay the rule, but granted an expedited schedule for hearing the case. Following this decision, in late January, Georgia Power joined states and other industry petitioners in asking the U.S. Supreme Court to stay the rule pending resolution of the litigation. In February 2016, the U.S. Supreme Court granted the emergency stay motion. As a result of the stay, many states, including Georgia, ceased working on a State Plan until the legality of the rule is resolved. The petitions for review of the CPP were fully briefed and argued in 2016. The legal challenges to the Section 111(b) new source rules have also been fully briefed and were scheduled for oral argument, however, that case is also being held in abeyance pending EPA review of the rule.

In light of EO 13783, on April 4, 2017, EPA announced its intent to review the CPP and the 111(b) new source standards. Pending its review of the final CPP and 111(b) new source standards, EPA requested that the D.C. Circuit Court hold the cases in abeyance. The court granted EPA’s request.

In October 2017, EPA proposed to repeal the CPP. The proposal states that EPA has reconsidered its interpretation underlying the CPP and is proposing to interpret the statute to mean that the rule can only consider technological or operational measures that can be applied to or at a single source to reduce emissions. As such, the proposal states that the CPP should be repealed because it exceeds EPA’s authority and the bounds of the CAA.

In August 2018, EPA proposed the Affordable Clean Energy (“ACE”) Rule to replace the CPP. ACE contains three main components. First, EPA proposes emission guidelines for states to develop plans to address GHG emissions from existing fossil-fired steam power plants. Second, EPA proposes new regulations that provide direction to both EPA and the states on the implementation of emission guidelines. The new proposed implementing regulations would apply to ACE and any future emission guidelines issued under section 111(d) of the CAA. Third, EPA is proposing an additional applicability test for determining whether a physical or operational change made to an electric generating unit may be a “major modification” triggering NSR. Specifically, EPA proposed revisions to the NSR permitting program to give states the option to adopt an hourly emissions increase test for such projects as an additional step in the determination of NSR applicability. Southern Company submitted comments on the proposal. According to status reports filed by EPA with the D.C. Circuit Court, EPA plans to finalize this CPP replacement rule in the first part of 2019.

In December 2018, EPA proposed revisions to the final 2015 NSPS for new, modified and reconstructed sources under Section 111(b) of the CAA. The proposal would revise the basis for the standards for new coal-fired units from partial CCS to supercritical design and would increase the standard from 1,400 lbs CO2/ MWh to 1,900 lbs CO2/ MWh. The proposal would also adjust the lower end of the possible range for standards applicable to modified and reconstructed coal-fired units to conform to the proposed new source standards. EPA did not propose revisions to the standards for natural gas-fired units. The proposal provides that these revisions to the new source standards will take effect for new units that commence construction, modification or reconstruction after the proposal is published in the Federal Register, which was December 20, 2018.

At this time, uncertainty remains regarding these regulatory activities due to both EPA and court activity. Currently, the 111(b) new source standards remain effective while the CPP remains stayed, but ACE, the replacement rule, has been proposed.

**GHG Reporting Rule**

EPA’s mandatory GHG Reporting Rule (40 CFR Part 98) was developed as the result of legislation passed by Congress in 2008, authorizing EPA to “collect accurate and timely greenhouse gas data to inform public policy decisions.” The Rule was finalized in October 2009 and requires annual reporting of GHG emissions for CO2, methane, nitrous oxide, and most fluroitnated gases beginning with calendar year 2010 for CO2, methane, nitrous oxide, and most fluorinated gases. The Rule applies to facilities that emit 25,000 metric tons a year or more of CO2 equivalent, which includes many of Georgia Power's fossil fuel-fired generating plants. In addition, the rule requires sulfur hexafluoride (SF6) emissions, which may be emitted from transmission and distribution equipment, to be reported beginning with calendar year 2011.

**2.13 New Source Review Enforcement**

NSR is a pre-construction permitting program under the Clean Air Act that can be triggered by changes to an emissions source (e.g., electric generating unit) that result in a “significant” increase of a regulated NSR pollutant. Changes to NSR regulations or their interpretation can impact the Company’s compliance methods and unit operations. Over the years, the Company has actively participated in various legislative, regulatory, and judicial proceedings addressing NSR issues, and expects NSR-related pressure from external parties to continue.

In 1999, EPA brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including Alabama Power and Georgia Power, alleging that these subsidiaries had violated the NSR provisions of the CAA and related state laws at certain coal-fired generating facilities. The civil action sought penalties and injunctive relief, including an order requiring installation of the best available control technology at the affected units. The court quickly dismissed the claims against Alabama Power because the claims were improperly brought in Georgia. The case against Georgia Power was administratively closed in 2001 and has not been reopened.

**2.14 316(b) Regulation**

Section 316(b) of the CWA requires that the location, design, construction, and capacity of any cooling water intake structure (“CWIS”) reflect Best Technology Available (“BTA”) for minimizing adverse environmental impact. Historically, NPDES permits have applied Section 316(b) on a case-by-case basis using best professional judgment. However, in 2004, EPA published a final 316(b) rule for the purpose of setting national standards for reducing impingement and entrainment of fish, shellfish and other forms of aquatic life at existing power plant CWISs. Industry and environmental groups challenged the rule, and in January 2007 (*Entergy corp. v Riverkeeper inc., et al.)*, the U.S. Court of Appeals for the Second Circuit overturned and remanded several provisions of the rule, including the use of cost-benefit analysis, to EPA for revision. As a result, EPA withdrew the rule and began developing a new proposal. In April 2009, the U.S. Supreme Court reversed the Second Circuit’s decision with respect to the rule’s use of cost-benefit analysis, and held that the EPA could consider costs in arriving at its standards and in providing variances from those standards for existing power plant CWISs.

In August 2014, EPA published a final 316(b) rule that established impingement mortality and entrainment requirements for existing power generating facilities and manufacturing and industrial facilities that are designed to withdraw more than 2 million gallons per day of water from waters of the U.S. and use at least 25 percent of the water they withdraw exclusively for cooling purposes. The new rule became effective in October 2014. Compliance is required “as soon as practicable” according to the schedule of requirements set by the permitting authority.

The final rule established permit application requirements for all facilities subject to the rule. All existing facilities must submit information regarding the source waterbody, cooling water intake structure(s), characterization of the biological community in the vicinity of the cooling water intake structure(s), cooling water system, and operational status of the facility. All existing facilities that withdraw more than 125 million gallons per day for cooling purposes must also submit additional information to characterize entrainment and assess the costs and benefits of installing various potential technological and operational controls.

Facilities subject to the rule must comply with one of seven options identified as a national BTA standard for impingement mortality, which include modified traveling screens and closed-cycle recirculating cooling. The permitting authority can also require additional measures to protect shellfish and federally-listed threatened and endangered species and designated critical habitat. For entrainment, the rule does not prescribe a single nationally applicable entrainment performance standard. Instead, EPA established a detailed regulatory framework for the determination of BTA entrainment requirements by the permitting authority on a site-specific basis. The rule identifies the information that must be submitted in the permit application and prescribes procedures that the permitting authority must follow in decision making and factors that must be considered in determining what entrainment controls and associated requirements are BTA on a site-specific basis.

In addition, the final rule establishes a process whereby the Fish and Wildlife Service and the National Marine Fisheries Service (“Services”) will be provided an opportunity to review permit applications of each facility seeking compliance with 316(b) of the CWA, either during a Section 7 consultation with EPA or during review of every permit application submitted to a State or Tribe, and to analyze impacts to federally-listed species and designated critical habitat that may result from operation of the facility’s CWIS. During this review, the Services will have an opportunity to recommend control measures, monitoring, and reporting recommendations on a site-specific and species-specific basis that will minimize adverse effects of CWIS operations.

In September 2014, the final rule was challenged by industry. In July 2018, the Second Circuit Court of Appeals issued its opinion addressing the challenges to EPA’s 2014 316(b) Rule for Existing Facilities. The court’s decision upheld the rule, the Fish and Wildlife Services’ biological opinion (“BO”), and the incidental take statement set forth in the BO, concluding that each action was based on a reasonable interpretation of the statutes and sufficiently supported by the record. The court also held that EPA complied with applicable procedures, including giving adequate public notice of the subjects and issues addressed by the final rule.

In November 2018, the Second Circuit issued its order officially denying the environmental groups petition for rehearing. Therefore, parties have until February 14, 2019 to file petition for review with the U.S. Supreme Court.

**2.15 Effluent Limitations Guidelines Revision**

In September 2009, EPA announced its plans to commence a rulemaking to revise the effluent limitations guidelines and standards for steam electric power plants. These ELGs, which were last promulgated in 1982, established technology-based effluent limitations for new and existing discharges. EPA’s decision to revise them was based on a multi-year study of power plant wastewater discharges, from which EPA concluded that pollutant discharges from coal-fired power plants would increase as new air pollution controls are installed and that technologies are available to reduce pollutant loadings from ash transport water and FGD wastewater.

Prior to proposing changes to the rule, EPA sent a lengthy and comprehensive Information Collection Request (“ICR”) to 733 facilities seeking technical and economic data about FGD wastewater, ash handling, metal cleaning wastes, surface impoundments, wastewater treatment systems, and landfill operations. In addition, EPA conducted a wastewater sampling program focused on the evaluation of FGD wastewater treatment systems (e.g., chemical precipitation, biological, and evaporation processes) for the removal of nutrients and metals. In June 2013, EPA published a proposed rule with eight regulatory options, four of which were “preferred” by EPA, covering seven wastestreams.

In November 2015, EPA published a final rule that revised or established standards for BPT, BAT, PSES, NSPS, and PSNS that apply to six wastestreams: FGD wastewater, fly ash transport water, bottom ash transport water, combustion residual leachate, gasification wastewater, and flue gas mercury control wastewater. Of these six wastestreams, fly ash transport water, bottom ash transport water, and FGD wastewater are the primary wastestreams applicable to Company operations. The 2015 Rule established a “zero discharge” standard for bottom ash transport water and fly ash transport water, with one exception applying to bottom ash transport water being reused for FGD make-up water (i.e., water recycled for the FGD in lieu of discharge). The ELG Rule also established stringent FGD wastewater limits for mercury, arsenic, selenium, and nitrate-nitrite. Furthermore, the 2015 Rule established a new voluntary incentive program that provided a firm compliance date of December 31, 2023 for plants willing to meet even more stringent FGD wastewater limits based on evaporation technology.

EPA also set new BAT limitations for direct discharges of “legacy wastewater.” Legacy wastewater refers to “FGD wastewater, fly ash transport water, bottom ash transport water, flue gas mercury control wastewater, or gasification wastewater generated prior to the date determined by the permitting authority that is as soon as possible beginning November 1, 2018, but not later than December 31, 2023.”

The 2015 Rule stated that compliance with all of the new, more stringent BAT limits does not apply until a date determined by the permitting authority that is “as soon as possible” beginning November 1, 2018, “but in no case later than December 31, 2023.” The permitting authority must consider relevant information from the regulated source to determine the appropriate applicability date within the November 1, 2018 and December 31, 2023 compliance window. For facilities in the voluntary incentive program for FGD wastewater, the date for meeting those limitations is December 31, 2023.

In November 2015, several groups filed Petitions for Review of the 2015 Rule, including industry, industry groups, including Utility Water Action Group (“UWAG”), environmental groups, and other interested parties. In December 2015, all petitions were consolidated in the Fifth Circuit and, in December 2016, opening briefs were filed with the court.

In March 2017, UWAG filed a Petition for Reconsideration of the 2015 Rule. On April 12, 2017, the EPA Administrator granted the Petition and announced an administrative stay pursuant to § 705 of the Administrative Procedures Act. This administrative stay applied to the compliance applicability dates of the more stringent BAT limitations and pretreatment standards of the 2015 ELG Rule (e.g., those for fly ash transport water, bottom ash transport water, FGD wastewater, combustion residual leachate, flue gas mercury control wastewater and gasification wastewater). On April 14, 2017, EPA asked the court to hold the case in abeyance for 120 days while it reconsidered specific aspects of the rule. The court granted EPA’s request on April 24, 2017, with the administrative stay becoming effective the following day.

On June 6, 2017, EPA issued a proposed stay-by-rule on the postponement of the more stringent BAT limitations and pretreatment standards of the 2015 ELG Rule. This ELG Postponement Rule was finalized on September 18, 2017, postponing the earliest compliance dates for the 2015 BAT effluent limitations for bottom ash transport water and FGD wastewater until November 1, 2020 rather than November 1, 2018. With issuance of the Postponement Rule, EPA withdrew the administrative stay that it had issued on April 12, 2017 such that the 2015 ELG Rule applicability dates for fly ash transport water, flue gas mercury control wastewater and gasification wastewater were once again in effect. EPA also stated that it planned to take approximately three years to propose and finalize a new rule addressing bottom ash transport water and FGD wastewater.

On October 3, 2018, the U.S. Court of Appeals for the Fifth Circuit conducted oral arguments concerning a 3rd party challenge on the 2015 ELG Rule’s BAT determinations for legacy wastewater and combustion residual leachate. A decision by the court is expected in early 2019.

Also in October 2018, EPA stated that it expected to issue a proposed rule for the ELG reconsideration in March 2019. EPA stated it is currently evaluating new information for this rulemaking that may change the limits for bottom ash transport water and FGD wastewater, but there is still uncertainty, at this time, as to what the final rule will require for compliance and when the new limits will apply. EPA stated that it expects to issue the final ELG Rule reconsideration in December 2019.

**2.16 Water Quality Standards and Total Maximum Daily Load**

Water quality standards are set by state law on toxics and other pollutants based on the protection of aquatic life and human health. A water quality standard establishes the designated use of a waterbody and the water quality criteria to protect that use. Water quality standards serve as the basis for establishing water quality-based effluent limitations in NPDES permits. To meet water quality-based effluent limits, additional controls may be required in the form of wastewater treatment (e.g., physical-chemical, biological, or evaporation systems) or in the form of adjustments to power plant operations.

In August 2015, EPA published its final rule to update the federal water quality standards regulations. The rule became effective in October 2015 and revises six program requirements: (1) the EPA Administrator's determinations that new or revised water quality standards are necessary; (2) designated uses; (3) triennial reviews; (4) antidegradation; (5) water quality standards variances; and (6) compliance schedules. The rule requires states to address EPA’s CWA 304(a) nationally-recommended water quality criteria and either adopt them or otherwise provide an explanation.

In July 2016, EPA revised the selenium aquatic life water quality criteria, superseding EPA’s 1999 CWA section 304(a) recommendations. The new criteria consist of fish tissue and water column elements with the fish tissue elements generally taking precedence over the water column elements. EPA subsequently proposed implementation guidance. During Georgia’s 2016 triennial review, Georgia EPD evaluated EPA’s new selenium criteria and decided not to adopt due to insufficient and unreliable laboratory methods to detect selenium levels below the recommended criteria concentration. In its response to comments, Georgia EPD stated that it will evaluate whether there are alternative EPA-approved laboratory methods that could be used to support a change in the selenium criteria during its 2019 triennial review process.

In December 2016, EPA proposed a draft field-based methodology for developing aquatic-life criteria for specific conductivity, which is an indicator of water salinity. Once finalized, Georgia EPD could use this methodology to adopt specific conductivity criteria into its water quality standards. UWAG and Electric Power Research Institute (“EPRI”) filed comments on the draft methodology in April 2017.

In addition, states are required to identify impaired waters (waters that do not meet applicable water quality standards), develop total maximum daily loads (“TMDLs”) for those waters, and impose point and non-point source limitations designed to bring the waters into compliance. A TMDL is a calculation of the maximum amount of a pollutant that a water body can receive and still safely meet water quality standards. In developing TMDLs, the states have the responsibility to establish reasonable, scientifically sound allocations and divide the estimated pollutant loads equitably among non-point and point sources, such as utilities. The state of Georgia has identified numerous impaired waters, and in some cases, developed and implemented associated TMDLs for waterways on which Georgia Power operates.

**2.17 Waters of the United States**

In July 2015, the EPA and the U.S. Army Corps of Engineers (“the Agencies”) published in the Federal Register a final rule re-defining WOTUS under the Clean Water Act with an effective date in August 2015. The final rule exerts very broad jurisdiction over water features, including features that have not previously been regulated, such as ephemeral drainages and isolated ponds on industrial facilities. The rule affects all CWA programs that rely on this definition, including the NPDES permit program under Section 402, the dredge-and-fill permit program under Section 404, and oil spill prevention and response programs under Section 311.

Thirty-one states, including Georgia, and a number of industry and environmental groups filed challenges to the rule. In October 2015, the Sixth Circuit issued an order staying the rule nationwide pending completion of the court’s review of the merits of the rule. As a result of multiple motions challenging the Sixth Court’s jurisdiction over the rule litigation, the court issued a decision in February 2016 holding that it has exclusive jurisdiction to decide the challenges of the rule. Several industry petitioners filed petitions for rehearing, but the Sixth Circuit denied them.

The National Association of Manufacturers filed a petition in September 2016 seeking U.S. Supreme Court review of the Sixth Circuit’s decision that the courts of appeals have jurisdiction over challenges to the WOTUS Rule. In January 2017, the U.S. Supreme Court agreed to review the case and subsequently, the Sixth Circuit stayed briefing on the merits of the rule pending the U.S. Supreme Court’s decision on jurisdiction.

In response to EO 13778, the Agencies undertook a two-step process to rescind the 2015 WOTUS Rule and adopt a new rule defining “waters of the U.S.” In July 2017, the Agencies proposed a rule to repeal the 2015 WOTUS Rule and recodify the regulatory text that was in place prior to the 2015 Rule. In November 2017, the Agencies proposed a rule (the “Applicability Rule”) to extend the applicability date of the 2015 Rule by two years, providing certainty and continuity while the Agencies consider revisions to the rule. The Applicability Rule was finalized in February 2018, extending the 2015 Rule applicability date to February 2020.

Prior to the Applicability Rule being finalized, the U.S. Supreme Court issued a decision in January 2018 finding that jurisdiction over challenges to the 2015 Rule lie in the district courts. As a result, the Sixth Circuit lifted its nationwide stay in February 2018. States, industry, and environmental groups filed new and renewed litigation over the 2015 Rule as well as the Applicability Rule in multiple district courts across the country.

The 2015 Rule is stayed in 28 states, including Georgia, pursuant to three district court orders despite a South Carolina district court overturning the Applicability Rule in August 2018. The injunctions from these three district courts will remain in place until the Agencies finalize their proposed 2015 WOTUS repeal and recodify regulatory text proposed rule or until a court issues a final decision on the merits of the 2015 Rule, either upholding or setting aside the Rule.

In December 2018, the Agencies released a proposal redefining WOTUS.  This proposal is the second step in the two-step process to review and revise the WOTUS definition consistent with EO 13778.

**2.18 Coal Combustion Residuals**

In May 2000, after nearly 20 years of study, EPA concluded that coal ash should not be regulated as a hazardous waste under RCRA Subtitle C and that states should continue to be the primary environmental regulators for coal ash management.

In June 2010, EPA issued a proposal for regulating the management and disposal of CCR. In April 2015, EPA published the final rule regulating CCR under Subtitle D of RCRA for non-hazardous waste (“Federal CCR Rule”). The rule became effective in October 2015 and applies to: (i) new and existing CCR landfills and surface impoundments (“units” or ash ponds), including any lateral expansions of such units that dispose or otherwise manage CCR generated by electric utilities and independent power producers (“IPPs”); and (ii) inactive surface impoundments, located at active electric generating facilities, regardless of fuel currently used (i.e. natural gas, coal, or oil). The rule established compliance requirements, compliance schedules, and technical criteria for these categories of CCR surface impoundments and landfills. The compliance requirements for CCR landfills and surface impoundments include operating standards, location restrictions, design standards, groundwater monitoring, closure and post-closure care, recordkeeping and internet posting. CCR surface impoundments are required to begin closure within specified time frames if they do not meet certain criteria in the rule, including structural integrity requirements, location restrictions, or, if unlined, groundwater protection standards. The rule incorporates alternative closure requirements that allow for surface impoundments to continue to receive CCR for a limited amount of time beyond a date for which it would otherwise have to begin closure if controls are not in place to manage CCR without an ash pond. The rule establishes requirements for closure, post closure care, and corrective action for certain, not all, CCR ash ponds and landfills. The Federal CCR Rule exempted inactive surface impoundments that closed within three years from the operating, design, and location criteria, as well as groundwater monitoring and post closure care. The Federal CCR Rule also exempted CCR units located at sites that ceased generating electricity, regardless of the fuel type, as of October 19, 2015.

In July 2015, several parties, including industry, industry groups and environmental groups filed legal challenges to the Federal CCR Rule. In June 2016, the D.C. Circuit Court approved a settlement addressing several issues that were raised in the CCR litigation. First, as part of the settlement, the court vacated the three-year closure exemption for inactive surface impoundments, which meant that inactive CCR units that were pursuing the three-year closure exemption would be subject to the same rule requirements as existing CCR surface impoundments, except on a revised schedule. EPA established a revised compliance schedule for these units in the “Extension Rule,” effective October 4, 2016, which extended the compliance dates by 547 days. Additionally, as part of the settlement, EPA agreed to finalize a rulemaking by June 2019 that will propose the following: (1) requirements relating to the use of vegetation for slope protection; (2) type and magnitude of non-groundwater releases that require a facility to comply with some or all of the Rule’s corrective action procedures; and (3) adding boron to the list of Appendix IV constituents. EPA also agreed to review whether to modify the rule’s existing alternative closure provision to specifically include non-CCR waste streams.

On October 16, 2016, the Georgia Department of Natural Resources Board adopted amendments to Georgia’s Rules for Solid Waste Management pertaining to the storage and disposal of CCR. The Georgia CCR Rule became effective on November 22, 2016 and is in addition to the Federal CCR Rule. It includes more stringent requirements than the Federal CCR Rule and requires permitting, oversight, and monitoring for Georgia facilities by Georgia EPD. For example:

* The Georgia CCR Rule adopts requirements from the Federal CCR Rule, but unlike the Federal CCR Rule, which only regulates certain facilities, the Georgia CCR Rule regulates all CCR landfills and ash ponds.
* CCR units in Georgia are regulated by Georgia EPD through a comprehensive permitting program, which is not required by the Federal CCR Rule. CCR unit development, operation, and closure must be conducted in accordance with the requirements in the permit, which is approved and enforced by Georgia EPD.
* All CCR landfills with existing solid waste permits were also required to submit a new CCR permit application to Georgia EPD by November 22, 2018. This included previously closed CCR landfills and ash ponds.
* These permits will set forth the requirements at each facility that Georgia Power will be subject to under the Georgia CCR Rule. The permitting process will include review of the Company’s plans, engineering design, public notice, and public comment.

In December 2016, the WIIN Act was approved by the U.S. Congress. It includes a framework whereby states can develop and implement a CCR permit program and operate in lieu of the federal rule as long as EPA approves the state program. In August 2017, EPA published guidance for states to use in developing and submitting a state CCR permit program for EPA approval under the WIIN Act. According to the WIIN Act guidance, once EPA determines that a state’s permit package is administratively complete, EPA has 180 days to approve or deny their program. An EPA-approved state permit program provides more regulatory certainty and reduces the burden of overlapping regulations. In March 2017, Georgia EPD submitted Georgia’s CCR Rule for EPA’s review, but at this time, EPA still has not acted on that submittal.

In September 2017, EPA responded to two petitions for reconsideration of the Federal CCR Rule by informing the petitioners that EPA has determined that it is appropriate to reconsider the Federal CCR Rule. Subsequently, EPA filed a motion asking the D.C. Circuit Court of Appeals to hold the active CCR litigation in abeyance and postpone oral argument in the case while it reconsiders the rule. The Court rescheduled oral argument to November 20, 2017 and requested additional information from both parties before it would decide whether to hold litigation in abeyance. EPA subsequently filed a status report with the Court, outlining a phased approach to amend the Federal CCR Rule. These amendments are expected to address the issues remanded to EPA in June 2016 as well as issues raised in the petitions for reconsideration. EPA proposed to issue the amendments in phases, Phase One and Phase Two, recognizing priorities and the importance to compliance deadlines of certain requirements.

In February 2018, the Georgia Department of Natural Resources Board adopted amendments to the Georgia Solid Waste Rules, including the Georgia CCR Rule. The amendments incorporate EPA’s vacatur of inactive surface impoundments closing by April 17, 2018 (three-year closure exemption) and associated extension deadlines for these units. The rule amendments also add requirements for the review and renewal of solid waste permits every 5 years in Georgia. Following adoption of the amended Georgia CCR Rule, Georgia EPD resubmitted Georgia’s CCR Rule to EPA in April 2018 and is awaiting approval.

In March 2018, EPA published the proposed Phase One Amendments to the Federal CCR Rule. The proposal addresses four provisions of the Federal CCR Rule that the Court remanded to EPA in 2016 and allows for certain risk-based, alternative performance standards for coal ash disposal units that operate under an approved state or federal permit program.

On July 30, 2018, EPA published the Phase One, Part One Amendments to the Federal CCR Rule, entitled “Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals From Electric Utilities: Amendments to the National Minimum Criteria (Phase One, Part One).” In this rulemaking, EPA finalized portions of the March 2018 proposed Phase One Amendments, addressing the following specific issues:

* Allows additional time (until October 31, 2020) to cease receipt of CCR and non-CCR waste streams for CCR surface impoundments that do not demonstrate compliance with the location restriction regarding placement above an uppermost aquifer and unlined units that have detected a statistically significant increase above a groundwater protection standard. Units failing to demonstrate compliance with the structural stability assessment, safety factor assessment, or four of the location restrictions (wetlands, unstable areas, seismic impact zones and faults) do not qualify for the additional time.
* Groundwater protection standards were established for four constituents that do not have EPA maximum contaminant levels.

* Allows a participating State Director or EPA where EPA is the permitting authority to:
  + Issue technical certifications in lieu of the current requirement to have professional engineers issue certifications.
  + Suspend groundwater monitoring requirements if there is evidence that there is no potential for migration of hazardous constituents to the uppermost aquifer during the active life of the unit and the post-closure care period.

Georgia EPD has not yet amended the Georgia CCR Rule to adopt EPA’s final Phase One, Part One rule.

On August 21, 2018, the D.C. Circuit Court of Appeals issued its decision in the CCR litigation. The decision addresses all remaining issues raised in the litigation. The Court:

* Denied EPA’s request to hold the case in abeyance pending reconsideration of the Federal CCR Rule
* Remanded the rule to EPA to reconsider (1) beneficial use considerations; (2) operation of unlined impoundments and classification of clay-lined impoundments; and (3) regulation of legacy ponds (inactive surface impoundments located at non-generating facilities)
* Denied Inudustry Petitioner’s challenge to EPA’s authority to regulate inactive surface impoundments

The Department of Justice chose not to seek rehearing on the Court's decision and the Court issued a mandate implementing the judgment on October 15, 2018. Issuance of the mandate did not immediately change the substance of the Federal CCR Rule. Instead, EPA will have to issue new rulemakings to address elements of the Court’s decision.

On October 22, 2018, Environmental Petitioners in the CCR litigation filed a petition for review of the Phase One, Part One rule amendments in the U.S. Court of Appeals for the District of Columbia Circuit.  Environmental Petitioners challenged several aspects of the rule, one of which is the extension of deadlines to October 31, 2020 to cease sending CCR and other waste streams to impoundments that demonstrate compliance with all except two of the specified performance criteria.

On December 17, 2018 EPA filed a motion to voluntarily remand the Phase One, Part One rule without vacating the rule. This would allow them to revise the deadline extensions through a new notice-and-comment rulemaking without disrupting the extensions that are currently in place. Environmental Petitioners, on the other hand, filed a motion to stay the portion of the Phase One, Part One rule that extended the cease receipt deadlines to October 31, 2020, while the challenge to the rule is litigated, or alternatively, for the court to vacate those extensions. Briefing is currently scheduled to conclude on or around February 8, 2019.

The extent of any impact will not be known until the U.S. Court of Appeals for the District of Columbia Circuit responds to the motions and/or the merits of the case, and EPA undertakes additional rulemaking action to establish further guidance.

Regarding Phase One, Part Two and Phase Two rulemakings, EPA is expected to take action in 2019 on these rulemakings.

**2.19 Other Considerations**

Currently, there are no proposed regulations relating to lead that may have an effect on the installation of equipment or changes in the operation of electric generating plants. In addition, ECS-Appendix C provides an overview of existing and proposed regulations in regards to low-level and high-level nuclear waste. Southern Company and Georgia Power will continue to monitor these issues and evaluate the Company’s strategy as changes occur.

**3.0 Environmental Strategy**

Based on the extensive regulatory and legislative issues previously described, Georgia Power has developed a comprehensive compliance strategy designed to provide reasonable, cost-effective plans to comply with applicable environmental requirements. Where appropriate, Georgia Power’s strategy considers efficiencies that may be gained through strategic planning with other Southern Company affiliates. Georgia Power’s environmental strategy process has evolved and been refined over the years and has adapted to the changing regulations, but the purpose of the process has always been to produce cost-effective compliance strategies that will maximize the benefit to customers while achieving environmental objectives and assuring compliance with all requirements. This environmental planning or strategy process is illustrated in the figure below (Fig. 3-1). The process is essential for internal decision making and communication.



Figure 3-1 Annual Environmental Strategy Development Process for Existing Generation Retrofits

**3.1 Strategy Process**

The process for developing the environmental compliance strategy includes the comprehensive involvement of a number of organizations within the Company, including environmental, governmental affairs, planning, fuels, engineering, finance, operations, communications, generating plants, and research groups. This integrated process includes four steps as discussed below.

1. **Predicting and integrating the outcome of new environmental requirements**. The first step involves gathering all available knowledge about current and possible future local, state, regional, and federal environmental requirements. The future requirements may be in the form of legislation that will need future rulemakings or in the form of draft or proposed new rules that must go through the rulemaking process to become final. Some rules may be part of an allowance-based cap and trade program over a regional or national scale and others may be local or state requirements that mandate specific requirements on specific plants. For many rules, the possibility that litigation will result in changes to the rule creates additional uncertainty.

2. **Developing assumptions on national, Southern Company, and Georgia Power Company levels.** In order to predict the impacts of the requirements on the generating plants, the Company must make assumptions to predict generating unit, Georgia Power, Southern Company, and national electric system responses to existing and future environmental requirements (in addition to demands for electricity). These assumptions include:

* Unit operating characteristics such as heat rates, capacity, and emission rates
* Fuel characteristics and costs, including natural gas, coal, and oil
* Allowance prices for cap and trade programs
* Control technology options and costs
* Existing and future generation demand

To appropriately consider future regulatory and market uncertainty, a scenario planning process is employed for long-term resource planning. A range of planning scenarios are developed and modeled as a part of the Company’s Integrated Resource Plan. This range is established through the work of a coordinated planning team consisting of internal and external subject matter experts and Company planning managers. The planning scenarios identify two fundamental dimensions that affect the range of potential futures for the electric utility industry – (1) fuel market demand and supply fundamentals, and (2) GHG policy.

3. **Application of generating unit-specific cost-effective control technology options.** The application of control technology is dictated initially by the anticipated environmental requirements for each specific generating plant and/or unit. In some cases, the plant or unit’s environmental control requirements are mandated, such as a plant-specific limit to meet ELG requirements. In other cases, such as the cap and trade program for SO2 established to address acid rain, utilities can choose the most cost-effective option, including fuel switching, applying a control technology, or purchasing emission allowances. The decision process reviews the cost, control effectiveness, regulatory timing requirements and operational considerations of each of these options for each unit. All of these considerations are taken into account in developing a unit-specific decision on the application of environmental control technologies. Several of the most important environmental control technologies for Georgia Power compliance are described in the technology review discussion that follows.

The availability or options for control technology can vary by pollutant, by process and by plant specifics. For example, when complying with SO2 reduction requirements, the choices may include fuel switching to lower sulfur coal, installing FGDs, or buying allowances. FGDs are also effective for the reduction of fine particulate matter and mercury. For NOX control, there are several control technology options available, such as low-NOX burners, SCR, and selective non-catalytic reduction (“SNCR”). Mercury emissions can be reduced through co-benefits from the combined operation of an SCR and a FGD, injection of activated carbon with or without alkali sorbents, and injection of chemical additives to the coal upstream of the boiler. A fabric filter technology such as a baghouse may be used for fine particulate matter and/or mercury reduction at some units.

In cases where the Company is responding to compliance with the CCR Rule or compliance with ELG requirements, technology choices include closure of ash ponds and installation of controls that allow facilities to eliminate the discharge of ash transport water, such as dry ash handling equipment, including remote drag chain conveyors and ash coolers. Similar options apply to potential treatment of FGD wastewater, where FGD operations, coal type and receiving stream flows influence wastewater chemistry and the treatment technology that may be most appropriate, such as physical, chemical, and biological treatment.

The following figure (Figure 3.1-1) illustrates possible control technologies and applications for coal-fired boilers.

**Emission Control Technologies for Coal-Fired Boilers**

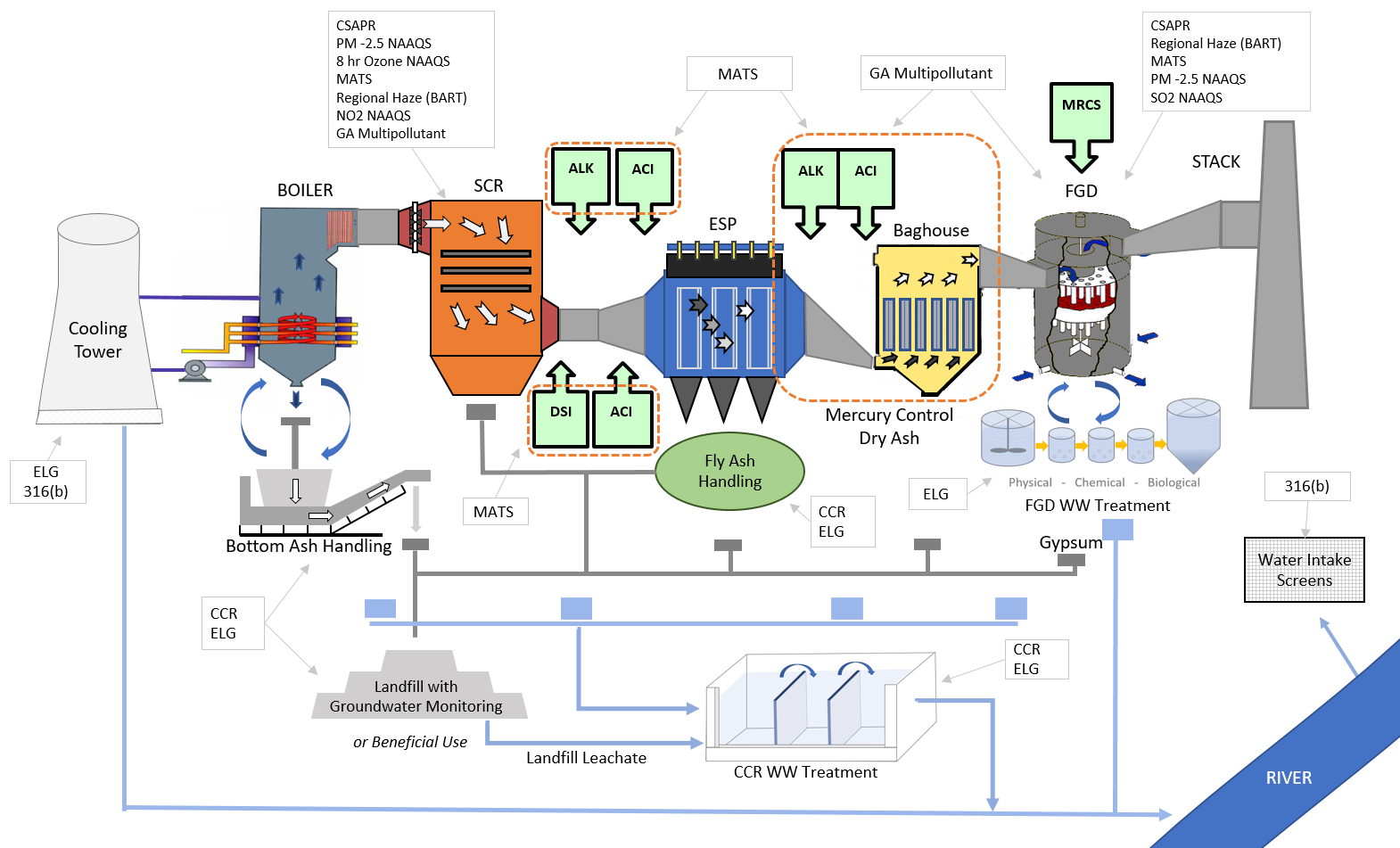


Figure 3.1-1 Possible Environmental Control Technologies for Coal-Fired Boilers

1. **Determining and evaluating the financial impacts of the strategy.** The final step is to include the environmental compliance strategy into unit retirement study scenarios. Some units and plants may not be able to achieve the required environmental limits in a cost-effective manner and would need to acquire additional allowances, switch fuels, or retire to comply. If environmental controls are mandated for a specific unit, then the economic value of the generating asset including future operating costs must be considered before application of the technology.

After the compliance strategy process is completed and analyzed across the various planning scenarios, a strategy is compiled on a unit level and reviewed annually based on the most current information. One major goal of the environmental strategy process is to maintain flexibility in compliance options and operations across the generating fleet.

A key advantage of this process is that it allows decision making on an incremental basis. While the strategy includes environmental control plans for the next 10 years, final decisions on specific environmental control projects are not made until commitments are required so that construction can commence. That is, while controls may be planned and required on a particular unit in 2023, no firm commitment to that plan will be made until necessary to assure that the control equipment is in place and operational when needed. This flexibility allows the company to adapt to changing requirements (such as the delay or change in scope of a final rule) and thus reduce costs to the customer.

Future regulatory and legislative requirements that could significantly impact both the scope and the cost of compliance over the next decade are incorporated into the strategy. Georgia Power will continue its involvement in emerging regulations, and these requirements will be incorporated into future strategy updates, as appropriate.

The uncertainty surrounding the legislative and regulatory environment reinforces the need for a flexible, robust compliance strategy. Accordingly, the strategy balances the need to make decisions on certain timelines (such as fuel and equipment purchases) with the need for more information relative to regulatory and economic drivers. The analysis will be updated to determine the most cost-effective compliance decisions while maintaining future flexibility in the strategy. Because the Company’s compliance strategy is impacted by factors such as new regulations, new legislation, changes to existing environmental laws and regulations, the cost of emissions allowances, technology advancements, and changes in fuel use, future environmental compliance costs will continue to be incurred.

**3.2 Strategy Assumptions**

Based on this extensive strategy process and the regulatory and legislative requirements discussed in Section 2.0, the Georgia Power environmental strategy is reviewed and updated each year. The environmental strategy combines the assumptions surrounding the regulatory requirements with the most cost-effective environmental control technology that is commercially available and results in specific environmental control applications across Georgia Power.

The current and expected requirements underlying the current system strategy include:

* **REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED**
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* Compliance with the Georgia Multipollutant Rule and the Georgia SO2 Emissions Rule through operation of SCRs, FGDs, baghouses, and switching to natural gas as applicable.
* MATS compliance with technology options including the co-benefits of SCR and FGDs, mercury re-emission control systems, injection of activated carbon, injection of alkali sorbents, baghouses, and switching to natural gas as the primary fuel.
* **REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED**
* **REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED**
* **REDACTED REDACTED REDACTED REDACTED REDACTED**
* Potential permitting requirements.

While there is uncertainty surrounding the stringency and timing of many of these rules, particularly the clean water and solid waste rules, they must be, and are currently, considered in the development of the Company’s environmental strategy.

**3.3 Environmental Compliance Technologies**

Research and development (“R&D”) is an integral part of the overall Georgia Power environmental strategy and compliance plan. Through research, technologies are considered, evaluated, developed, and selected for possible implementation to meet compliance with federal and state regulatory requirements. Technology-related decisions are made based on compliance alternatives, technical review (often following actual testing), schedules, equipment-vendor price quotes, total costs over the useful life, specific unit issues, and performance guarantees. Operations, maintenance, and cost effectiveness are important parts of the decision-making process.

Since the implementation of the CAAA of 1990, R&D has been crucial for Southern Company in assuring that the best possible environmental compliance strategies are selected for implementation at Georgia Power. ECS-Appendix B provides a list of technologies considered in an ongoing effort to reduce emissions, meet mandated requirements in a timely manner, maintain system reliability, and assure cost-effective generation for customers.

Research programs are conducted at Georgia Power plants, at other Southern Company system plants, and through industry affiliations at plants across the U.S. and around the world. To minimize cost and risk, only proven technologies should be implemented commercially. These industry R&D efforts are leveraged to test low-NOX burners, precipitators, catalyst materials for SCRs, FGDs, mercury reduction systems, CCS, and other equipment and have contributed to Georgia Power’s ability to meet stringent requirements while continuing to provide affordable energy for customers.

The Water Research Center (“WRC”), for example, which is located at Georgia Power’s Plant Bowen, provides a venue for developing and testing various types of cutting-edge technologies to reduce power plant water withdrawals and consumption and improve the quality of water related to power generation. Since it began operation in 2012, research conducted at the WRC has and continues to inform technological strategies for achieving cost-effective environmental compliance.

In partnership with EPRI, Southern Research, and other industry partners, Southern Company and Georgia Power are expanding the WRC at Plant Bowen to become the Water Research and Conservation Center with locations at Plants Bowen and McDonough-Atkinson. The center at Plant Bowen will maintain its focus on researching technologies to maintain compliance with current and future environmental regulations, while continuing the testing and evaluation of pilot systems that are nearing commercialization. The new center at Plant McDonough-Atkinson will promote long-term solutions and advancements in power plant cooling systems leading to reduced freshwater withdrawal and consumption as well as improved plant efficiency while optimizing total cost and energy generation. The center will provide a venue with the necessary infrastructure, like the one at Plant Bowen, that the Company and project partners can use in developing and testing technologies to reach these goals.

Additionally, the Company is developing a center for beneficial use of harvested CCR. Using CCR that has been stored in closed ponds or landfills for commercial products is an effective way to recycle CCR for beneficial use. Scientific research and larger-scale process engineering tests and demonstrations are necessary to further develop advanced processing and beneficial use technologies that can expand the use of CCR into more markets and increase the amount of stored CCR that can be harvested for beneficial use.

The current Georgia markets for CCR use, **REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED**. This center aims to develop new technologies or processes that drive downward cost pressure associated with beneficiation and expand current and potential markets. This downward cost pressure would create an adjustable mechanism to obtain market equilibrium such that beneficial reuse from operating power plants is preserved. In addition, technology developments or enhancements to beneficiate CCR could ultimately allow Georgia Power to reduce the amount of CCR that is stored in landfills or reclaim CCR already stored in landfills and ash ponds. This would result in lower capital and O&M costs for CCR storage in landfills. The strategy associated with implementing a cost-effective mechanism to inject beneficiated ash into the market, as well as limiting the quantity of CCR in landfills, focuses on current and future customer benefit.

This center will be built and operated by EPRI at a company-owned coal-fired power plant and will be used for testing and development of technologies for using harvested CCR. The objectives for the center are to:

* review commercial beneficiation processes
* speed development of emerging beneficial use technologies
* understand performance of reuse products
* develop realistic cost profiles

The facility will allow for pilot projects and continued testing of technologies to potentially produce valuable products from ponded and landfilled CCR. The research center will be a collaborative project with other electric power utilities supporting construction and operations through funding from the EPRI.

**4.0 Strategy Results and Financial Summary**

Since 1990, Georgia Power has faced a host of new environmental regulations and requirements as described in Section 2.0. The Company has consistently responded with a timely, comprehensive, and cost-effective strategy that has either met or exceeded new and revised environmental regulations, allowing our facilities to meet the needs of customers.

Historically, the applicable regulations and the Georgia Power compliance strategy have centered largely on air quality and emissions, with a focus on the reduction of SO2 and NOx emissions as well as mercury and other HAP emissions.

More recently, while still focused on operation and compliance activites related to air quality regulations, the Company’s environmental compliance strategy concentrates on compliance with increasing and significant regulations governing water resources and solid waste management.

This section provides the Company’s compliance strategy for air, water, and solid waste management requirements.

**4.1 Air Compliance Strategy Review**

The air emission reductions that Georgia Power has achieved to date have been driven by the need to comply with many CAA and state regulations focused on SO2 and NOX emissions from power plants, including the Acid Rain Program, CSAPR, CAVR, and state regulations designed to achieve attainment with the ozone and PM NAAQS. In addition, state and federal regulations, such as the Georgia Multipollutant Rule and MATS, have also required reductions in emissions of mercury and other HAPs through installation of controls on the Company’s power plants.

Table 4.1-1 (below) summarizes the emissions control equipment installed at Georgia Power’s coal-fired units since the 1990 CAAA. Continuing to operate the control equipment, as required to remain in compliance with the applicable rules, requires ongoing operation and maintenance expenditures. The Selected Supporting Information section of Technical Appendix Volume 1 outlines such anticipated estimates for the ongoing operational and maintenance requirements. ECS-Appendix Aprovides a reference list of the acronyms/abbreviations used in the table for both controls and vendor names. See ECS-Appendix B for additional technical summaries on environmental control technologies.

**Table 4.1-1 Current Emissions Control Equipment**

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| **Unit** | **Unit Type** | **NOX Control** | **SO2 Control** | **Mercury Control** |
| Bowen 1 | Tangentially Fired | LNCFS II / SCR | FGD | ACI / ALK / MRCS / FGD / SCR |
| Bowen 2 | Tangentially Fired | LNCFS II / SCR | FGD | ACI / ALK / MRCS / FGD / SCR |
| Bowen 3 | Tangentially Fired | LNCFS II / SCR | FGD | ACI / ALK / BH / FGD / SCR |
| Bowen 4 | Tangentially Fired | LNCFS II / SCR | FGD | ACI / ALK / BH / FGD / SCR |
| Gaston 1 | Wall Fired | LNB | Gas Fired | Gas Fired |
| Gaston 2 | Wall Fired | LNB | Gas Fired | Gas Fired |
| Gaston 3 | Wall Fired | LNB | Gas Fired | Gas Fired |
| Gaston 4 | Wall Fired | LNB | Gas Fired | Gas Fired |
| Hammond 1 | Wall Fired | LNB | FGD | ACI / ALK / FGD |
| Hammond 2 | Wall Fired | LNB | FGD | ACI / ALK / FGD |
| Hammond 3 | Wall Fired | LNB | FGD | ACI / ALK / FGD |
| Hammond 4 | Wall Fired | LNB / OFA / SCR | FGD | ACI / ALK / FGD / SCR |
| McIntosh 1 | Wall Fired | OFA | - | ACI / DSI |
| Scherer 1 | Tangentially Fired | LNCFS III / SCR | FGD | Baghouse / ACI |
| Scherer 2 | Tangentially Fired | LNCFS III / SCR | FGD | Baghouse / ACI |
| Scherer 3 | Tangentially Fired | LNCFS III / SCR | FGD | Baghouse / ACI |
| Wansley 1 | Tangentially Fired | LNCFS II / SCR | FGD | ACI / ALK / MRCS / FGD / SCR |
| Wansley 2 | Tangentially Fired | LNCFS II / SCR | FGD | ACI / ALK / MRCS / FGD / SCR |
| Yates 6 | Tangentially Fired | LNB, SOFA | Gas Fired | Gas Fired |
| Yates 7 | Tangentially Fired | LNB, SOFA | Gas Fired | Gas Fired |

The following discussion details Georgia Power’s compliance strategy as it relates to each regulatory requirement.

**4.1.1 SO2 Compliance**

Since 2007, the SO2 controls strategy and schedule for Georgia Power have been largely mapped out by the requirements in the Georgia Multipollutant Rule and the companion SO2 Emissions Rule. The Georgia Multipollutant Rule required the installation and operation of FGD systems at certain units by specified dates between 2008 and 2015 and required switching from coal to natural gas for units at Plant Yates. In addition to the reductions that have been driven by the Georgia Multipollutant Rule, the sections below review the historical, ongoing, and expected potential impacts of other rules on the SO2 compliance strategy.

**Acid Rain SO2 Compliance Review**

The Acid Rain Program sets a cap on SO2 emissions from power plants by allocating a fixed number of allowances to each unit subject to the program. At the end of each year, a unit must surrender allowances in an amount equal to the number of tons of SO2 emitted. Unused allowances may be sold to offset the cost of compliance or saved, i.e., banked, for future use. Initial allowance allocations were received in 1995 when Phase I of the program began. When Phase II began in 2000, the number of allowances available was reduced to limit SO2 emissions to 50% below 1980 levels by 2010.

Historically, Georgia Power’s compliance strategy relied heavily upon use of low-sulfur coal. However, today the strategy relies on FGDs for SO2 control at the larger coal-fired units. For purposes of Acid Rain compliance, Georgia Power currently expects **REDACTED REDACTED REDACTED** **REDACTED REDACTED REDACTED** **REDACTED REDACTED REDACTED** **REDACTED REDACTED REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED**. Under current regulations for the Acid Rain Program, projections show that **REDACTED REDACTED** **REDACTED REDACTED REDACTED** **REDACTED REDACTED REDACTED** **REDACTED REDACTED REDACTED** **REDACTED** **REDACTED** **REDACTED**.

**CSAPR SO2 Compliance Review**

In 2015, Phase I of the CSAPR SO2 program began. Similar to the Acid Rain Program, CSAPR sets a cap on SO2 emissions from power plants subject to the program and requires units to surrender allowances in an amount equal to the number of tons of SO2 emitted for compliance. However, unlike the Acid Rain Program, CSAPR prevents or limits trading of allowances between certain states. Phase II of the CSAPR SO2 program began in 2017 and increased SO2 reduction requirements to help states fulfill certain SIP obligations related to the PM NAAQS and interstate transport.

The compliance strategy for CSAPR Phase II primarily relies on FGDs for SO2 control at coal-fired units. For purposes of Phase II CSAPR compliance, Georgia Power currently expects **REDACTED** **REDACTED REDACTED REDACTED** **REDACTED REDACTED** **REDACTED** **REDACTED** **REDACTED**. Under current regulations for the CSAPR SO2 trading program, projections show that **REDACTED** **REDACTED REDACTED REDACTED** **REDACTED** **REDACTED REDACTED REDACTED** **REDACTED REDACTED** **REDACTED** **REDACTED** **REDACTED REDACTED REDACTED**

**MATS SO2/Acid Gases Compliance Review**

Under the MATS Rule, a unit that has a FGD may comply with an emissions limit for SO2 as an alternate to the hydrogen chloride (“HCl”) limit. Since FGDs are effective at removing both HCl and SO2, the Company’s coal-fired units that have FGDs installed can, in general, meet the MATS limit. However, due to the stringency of the MATS standard and limited operational flexibility relative to the Georgia Multipollutant Rule and SO2 Emissions Rule, the Company has performed plant-specific optimization projects on the existing FGDs at Plants Bowen, Hammond, and Wansley to minimize potential impacts to reliability in the future. Coal-fired units without FGDs use a low chlorine/low SO2 fuel (e.g. Powder River Basin coal (“PRB”)) and employ Dry Sorbent Injection (“DSI”), as needed, to meet the MATS HCl limit. Additional detail regarding the MATS strategy for SO2/acid gases and the other MATS limits is provided in Section 4.1.3.

**Future Rules SO**2 **Compliance Review**

Future regulations related to the NAAQS for SO2 and PM2.5 and the Clean Air Visibility Rule may drive the need for additional SO2 reduction strategies in the future.

While the outcome of these future rules is unclear, **REDACTED** **REDACTED REDACTED** **REDACTED** **REDACTED REDACTED REDACTED** **REDACTED REDACTED** **REDACTED REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED.** Coal-fired units may be subject to more stringent SO2 limits in the future.

In this IRP, Georgia Power is requesting decertification of Plant Hammond Units 1-4 and Plant McIntosh Unit 1. If the Georgia PSC approves the request for decertification, **REDACTED** **REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED**

**4.1.2 NOX Compliance**

Since 2007, like SO­2, the NOx controls strategy and schedule for Georgia Power have also been largely mapped out by the requirements in the Georgia Multipollutant Rule. The sections below review the historical, ongoing, and expected potential impacts of other rules on the NOx compliance strategy.

**Acid Rain NOx Compliance Review**

Instead of a cap and trade based system, the Acid Rain Program for NOX established emissions limitations for certain coal-fired boilers, or groups of boilers in an averaging plan. The Georgia Power NOX compliance strategy for Acid Rain compliance historically consisted of installing low-NOX burners, OFA systems, burner tips, and associated controls. Georgia Power complies with the NOx requirements under the Acid Rain Program through a NOx Averaging Plan. Under the plan, affected units covered by the regulation must achieve an annual-average NOx emission rate below the specified limit.

The NOX Averaging Plan is filed with each state environmental agency and EPA. Averaging of NOX emissions lowers system cost and further ensures compliance with Acid Rain regulations. Subsequent regulations, including ozone nonattainment area requirements, CSAPR, and the Georgia Multipollutant Rule, have required further NOx reductions which provide adequate control for Acid Rain Program NOX compliance. Controls installed under these regulations, as discussed below, reduce NOX emissions well below Acid Rain Program requirements.

**Ozone Nonattainment Compliance Review**

To meet the NOX reduction requirements for the 1-hour and 1997 8-hour ozone standards, additional controls beyond those necessary for the Acid Rain Program were required. Various alternatives were considered and evaluated on a technological, operational, and economical basis, including SCR, overfire air (“OFA”), low NOx burners, use of natural gas, PRB coal, and various other low NOx technologies. Analysis of the best solution for NOX reduction at affected units considered the capital and operating cost of the controls, as well as their performance and resulting production cost savings. Actual compliance implementation decisions were made based on a technical review of the compliance alternatives, equipment-vendor price quotes, specific unit issues, and performance guarantees. In addition to controls required to comply with ozone nonattainment area requirements, the Georgia Multipollutant Rule required the installation and operation of SCR systems at certain additional units by specified dates between 2008 and 2015. The Company expects to continue to operate and maintain these controls to comply with the ozone season NOx emission limits applicable to each unit, or each group of units when using emissions averaging, as applicable.

After EPA redesignation of 15 counties in the Atlanta metropolitan area to attainment with the 2008 ozone NAAQS in June 2017, a smaller, seven county area was designated as nonattainment with the 2015 ozone NAAQS in April 2018. However, the area was classified as “marginal” nonattainment, meaning that adoption of additional controls is not required to achieve attainment in a timely manner. Therefore, Georgia Power currently does not expect that additional NOX reductions will be required as a result of the 2015 ozone NAAQS.

**CSAPR Annual NOX Compliance Review**

The CSAPR Annual NOX trading program functions in a manner very similar to that of the SO2 trading program, except that participating states are not prevented from trading with one another. The compliance strategy for Phase II of the CSAPR Annual NOX program primarily relies on SCRs for NOX control at the larger coal-fired units. For purposes of Phase II CSAPR compliance, Georgia Power currently expects **REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED** Under current regulations for the CSAPR NOX trading program, projections show that **REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED**

**CSAPR Seasonal NOX Compliance**

The compliance strategy for Phase II of the CSAPR Seasonal NOX program is functionally identical to that of the CSAPR Annual NOX program. Beginning in 2017, the CSAPR prevents interstate trading of seasonal allowances between two exclusive trading groups – Group 1 and Group 2 – similar to the CSAPR SO2 program. Currently, Georgia is the only state in Group 1. Under current regulations for the CSAPR Seasonal NOX program, projections show that **REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED**

**Future Rules NOx Compliance Review**

Expected regulations related to the NAAQS for ozone and CAVR may drive the need for additional NOx reductions strategies in the future. While the outcome of these future rules is unknown, **REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED**

**4.1.3 Mercury and Air Toxics Standards**

Georgia Power and Southern Company have long been uniquely positioned to understand and implement mercury control technology appropriately across the operating fleet in large part due to the wealth of research and demonstration experience. Southern Company has collaborated with the U.S. Department of Energy, EPRI, equipment suppliers, and other utilities on mercury research. Building off of its previous experience, the Company’s research and testing program has enabled it to make individualized, targeted decisions for each unit that optimizes the available technology while minimizing costs to the customer.

On April 16, 2016, Georgia Power began complying with the MATS Rule, which established stringent emission limits for mercury, particulate matter (as a surrogate for certain metals), and acid gases. The compliance strategy for the MATS Rule is unit-specific. While not yet final, EPA’s MATS RTR proposal does not propose any changes to the MATS standards applicable to the Company’s units. Therefore, Georgia Power expects to continue to use the following MATS compliance strategies for each scrubbed and unscrubbed unit.

**MATS Compliance Strategy for Units with FGD**

Coal-fired units with FGDs have the option to comply with either the MATS HCl or alternate SO2 emissions limit. For mercury, significant reductions are achieved on bituminous coal-fired units through the mercury reduction and capture co-benefits of the SCR and FGD. However, additional incremental mercury reductions were required to comply with the MATS mercury limit on a continuous basis. Therefore, GPC installed activated carbon and alkali sorbent (e.g., hydrated lime) injections systems on all units at Plants Bowen, Hammond, and Wansley. In addition, to minimize operational costs associated with the injection systems, Mercury Re-emission Control Systems (“MRCSs”) were also installed at Plant Bowen Units 1-2 and at Plant Wansley Units 1-2 to prevent re-emission of mercury once it is captured in the FGD. To ensure compliance with the MATS particulate matter limits, optimization of the existing electrostatic precipitators (“ESPs”) was performed at Plant Bowen Units 1-2, Plant Hammond Units 1-4, and Plant Wansley Units 1-2, while baghouse retrofits were necessary at Plant Bowen Units 3-4 to capture additional particulate in the flue gases in order to comply.

For the subbituminous coal-fired units at Plant Scherer, existing controls installed to comply with the Georgia Multipollutant Rule (i.e. FGD, SCR, and baghouse with activated carbon injection (“ACI”)) are used to comply with the MATS limits.

Additionally, given the stringency of the MATS requirements and the resulting reduction in operational flexibility, additional measures were implemented at Plants Bowen, Hammond, and Wansley to optimize balance of plant performance and ensure reliability of mercury, acid gas, and particulate matter controls.

**MATS Compliance Review for Units without FGD**

For units that do not have FGDs, the compliance strategy is based on site-specific factors and evaluations. The strategies for these units are discussed below.

Plant McIntosh Unit 1, which switched to subbituminous PRB coal in 2014, is able to comply with MATS using alternatives to FGD and baghouse technology. Use of PRB, which is a low-chlorine and low-sulfur coal, enables compliance with the MATS limits, and DSI was installed to ensure compliance under all operating scenarios. Plant McIntosh Unit 1 uses ACI for mercury control and DSI for acid gas control. The existing ESP for this unit was also optimized to maintain emissions performance with the additional particulate loading from the injection systems.

Plant Yates Units 6 and 7 and Plant Gaston Units 1-4 switched to natural gas as the primary fuel. By switching to natural gas, these units are no longer subject to MATS because MATS applies only to coal- and oil-fired units. The Company has determined that use of natural gas at these plants is the most economic choice for customers and is feasible both from a boiler technology as well as a natural gas fuel supply perspective.

For other unscrubbed coal- or oil-fired steam generating units, options for MATS compliance was very limited and/or cost prohibitive. Thus, these units were retired.

**4.1.4 Greenhouse Gases**

On October 23, 2015, EPA finalized the CPP, which set guidelines for CO2 emission reductions from existing coal-, oil-, and natural gas-fired electric generating units. The CPP is not directly applicable to individual sources, but required states to develop a state-specific compliance plan.

Numerous parties filed petitions for review and accompanying motions to stay the rule pending resolution of the litigation with the D.C. Circuit Court. On February 9, 2016, the U.S. Supreme Court granted a stay of the CPP, which put the rule on hold while the legal challenge proceeds through the courts. While the case was argued before the D.C. Circuit Court in September 2016, the court is currently holding the litigation in abeyance.

In October 2017, EPA began an effort to repeal and replace the CPP starting first with the CPP repeal proposal. On August 21, 2018, EPA proposed the ACE Rule which would replace the CPP and establish procedures for states to develop plans to address carbon emissions from existing power plants. EPA plans to finalize the ACE Rule in the first part of 2019. At this time, there is still significant uncertainty regarding the future of the CPP and ACE due to both EPA and court activity. Developing detailed analysis of the implications of the ACE Rule would be premature and speculative for this filing. The rule has yet to be finalized, state plans have yet to be developed, and potential legal proceedings have yet to occur. As clarity on the rule increases, and once state plans and any legal proceedings develop, the Company will undertake analyses to determine the implications of the rule.

Additionally, Georgia Power expects that efforts by the U.S. Congress to regulate carbon emissions in some manner will continue. In the past, carbon-related legislation has included carbon tax and cap-and-trade program proposals. Both of which the Company may utilize to analyze various compliance strategies.

While there is still significant uncertainty regarding the future form of carbon legislation, as well as the CPP and ACE, the Company expects the implications to be adequately represented by the Company’s approach to handling CO2 in its modeling analysis. This approach, as discussed in section 1.0, has resulted in both the most economic outcome for customers and CO2 emission reductions of more than 50 percent since 2007. Georgia Power will continue to monitor the CPP and ACE as well as legislative efforts to regulate carbon and develop additional compliance strategies as it becomes necessary.

**4.2 Water Compliance Strategy Review**

The water compliance strategy considers a variety of regulations related to both water quality and biological management. The strategy considers both nationwide standards as well as state requirements developed for specific water bodies. The strategy and actions required to meet these regulations are discussed below.

**4.2.1 Cooling Water Intake Structures**

**REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED** Georgia Power is continuing to evaluate compliance alternatives for the Section 316(b) rule with the current strategy based on plant-specific evaluations. **REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED** A summary of the cooling types and associated controls included in the Company’s strategy for each unit are included in Table 4.2.2-1.

In this IRP, Georgia Power is requesting decertification of Plant Hammond Units 1-4 and Plant McIntosh Unit 1. If the Georgia PSC approves the request for decertification, **REDACTED** **REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED** If decertification is not approved for Plants Hammond and McIntosh Unit 1 **REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED**

**4.2.2 Wastewater Treatment Facilities**

There are several drivers that require new or supplemental wastewater treatment on multiple waste streams at Georgia Power plants. The final ELG Rule includes stringent requirements for handling of fly ash, bottom ash, and landfill leachate. In addition, the rule includes wastewater treatment limits for installed and operational FGDs across the Georgia Power system. The Company’s compliance strategy for the ELG and CCR Rules builds on and refines the Commission-approved ECS in the 2016 IRP filing (Docket No. 40161) as well as the Company’s 2017 ECS filing with the Commission. These requirements are being incorporated in Georgia Power’s NPDES permits by state regulators with allowance for changes necessitated by the ELG Postponement Rule.

As discussed in Section 2.15, the ELG Rule requires zero discharge of ash transport water, which requires ash handling conversions be implemented. These conversions can be either ‘wet’ or ‘dry’ but must meet the zero discharge standard. The Company’s strategy for compliance for fly ash includes conversions to pneumatic (dry handling) systems that convey ash via vacuum/blowers to collection hoppers and silos for reuse or disposal at Plants Bowen, Scherer, and Wansley. Similarly, the ELG Rule requires zero discharge of bottom ash and compliance options include conversions that are more complex and require significant site-specific analysis related to coal type, water volumes, space availability and boiler lay-out. Based upon these considerations, the conversions may be ‘wet’ or ‘dry’, but must result in zero discharge. The two primary technology options for bottom ash handling are either an under-boiler or remote system, which will primarily be determined by space availability and headroom constraints under the boiler. The Company’s strategy for bottom ash transport water compliance is **REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED** **REDACTED** If the Georgia PSC approves the request for decertification **REDACTED REDACTED REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED** If decertification is not approved for Plants Hammond and McIntosh Unit 1 **REDACTED** **REDACTED** **REDACTED REDACTED REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED**

**REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED** Because the ELG Rule regulates other wastewater streams from coal-fired plants to include low volume wastewater (“LVW”), combustion residual lechate, and coal pile runoff **REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED REDACTED** **REDACTED** **REDACTED** **REDACTED**

If the Georgia PSC approves the request for decertification **REDACTED** **REDACTED REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED REDACTED** **REDACTED** **REDACTED** If decertification is not approved for Plants Hammond and McIntosh Unit 1 **REDACTED** **REDACTED REDACTED** **REDACTED** **REDACTED** **REDACTED REDACTED**

Finally, due to the stringent ELG requirements for FGD wastewater, the strategy includes **REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED  
REDACTED** **REDACTED** **REDACTED** Compliance with the ELG Rule for FGD wastewater is unique, site-specific, and requires detailed analysis and planning. Many factors will influence the ultimate technology installation for a power plant, such as: fuel type, FGD type, capacity factors, sourcewater quality, and air pollution control equipment. It should also be noted that FGD wastewater treatment systems are not widely deployed in the U.S. and therefore, the Company has undergone significant review and consideration to develop a strategy to ensure cost-effective technology performance, reliability, and compliance. Based on the existing ELG Rule, the Company’s FGD wastewater strategy includes **REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED** If the Georgia PSC approves the request for decertification, **REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED** **REDACTED** If decertification is not approved for Plant Hammond, **REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED**

In addition to FGD wastewater technology choice, implementation scheduling is also difficult to predict for each plant. The timing of decisions and installation is dependent on the reconsideration of the regulation, as well as the existing controls that may be in place. Based on current requirements in the rule, the Company has developed a design, procurement, construction, and commissioning schedule that provides a strategy to be in-compliance by the latest applicability date of December 31, 2023.

The installation of new treatment systems for ash handling, FGD wastewater and CCR wastewater will result in additional operation and maintenance costs. These costs will primarily be operation and maintenance activities, but will also include costs associated with chemical commodities.

The Company’s current wastewater treatment strategy for compliance with the ELG and CCR rules is illustrated in Table 4.2.2-1.

**Table 4.2.2-1 Cooling Type / Wastewater Treatment / ELG Technologies**

|  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- |
| **Unit** | **Unit Type** | **Cooling Type** | **Bottom Ash Transport Water** | **Fly Ash** | **FGD WW** | **CCR WW** | **316(b) Cooling Water** |
| Bowen 1 | Tangentially Fired | Closed-Cycle | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| Bowen 2 | Tangentially Fired | Closed-Cycle | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| Bowen 3 | Tangentially Fired | Closed-Cycle | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| Bowen 4 | Tangentially Fired | Closed-Cycle | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| Gaston 1 | Wall Fired | Once-Through | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| Gaston 2 | Wall Fired | Once-Through | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| Gaston 3 | Wall Fired | Once-Through | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| Gaston 4 | Wall Fired | Once-Through | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| Hammond 1 | Wall Fired | Once-Through | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| Hammond 2 | Wall Fired | Once-Through | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| Hammond 3 | Wall Fired | Once-Through | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| Hammond 4 | Wall Fired | Once-Through | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| McIntosh 1 | Wall Fired | Once-Through | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| Scherer 1 | Tangentially Fired | Closed-Cycle | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| Scherer 2 | Tangentially Fired | Closed-Cycle | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| Scherer 3 | Tangentially Fired | Closed-Cycle | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| Wansley 1 | Tangentially Fired | Closed-Cycle | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| Wansley 2 | Tangentially Fired | Closed-Cycle | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| Yates 6 | Tangentially Fired | Closed-Cycle | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| Yates 7 | Tangentially Fired | Closed-Cycle | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| *No footnote for In-Service projects. (1) Projects Under Construction, (2) ECS Strategy Projects* | | | | | | |  |

**4.3 Solid Waste Management Compliance Strategy Review**

The federal and state CCR rules regulate storage and disposal of CCR and apply to CCR landfills and ash ponds. The compliance requirements include location restrictions, design criteria, operating criteria, groundwater monitoring and corrective action, closure and post-closure care, recordkeeping, notifications, and posting of information to the internet. Under both the federal and state CCR rules, ash ponds are required to close if they do not meet certain technical criteria, including structural integrity requirements, groundwater protection standards, and location restrictions. In compliance with the Federal CCR Rule and the more stringent Georgia CCR Rule, Georgia Power has identified its strategy to close the Company’s ash ponds and implement these new, more stringent measures.

**Background and Compliance Requirements**

Ash ponds were originally designed, installed, and operated to function as a treatment system for power plant wastewaters, and they have effectively served in this capacity for decades. These ponds were previously identified by EPA in both 1974 and 1982 as the Best Practicable Control Technology and are used as settling basins to remove particulates in the wastewater generated from the power production process to comply with NPDES permit requirements.

As detailed in Section 2, the Company’s CCR ash ponds and landfills are subject to EPA’s Federal CCR Rule, as well as the more stringent requirements in the Georgia CCR Rule. The Company will, therefore, have dual compliance requirements, under the Federal and Georgia CCR Rules separately, until Georgia EPD’s CCR program is approved by EPA per the WIIN Act.

Georgia Power’s ash pond closure plans and compliance strategy are designed to comply with the Federal CCR Rule, as well as the more stringent requirements of the Georgia CCR Rule. The Georgia CCR Rule regulates all ash ponds and landfills in the state and requires a comprehensive permitting program through which Georgia EPD will direct and approve all permits and actions to ensure ash pond closures meet the requirements of the CCR rule and are protective of human health and the environment. Georgia was one of the first states in the country to develop its own rule regulating management and storage of CCR such as gypsum and coal ash.

In compliance with Georgia’s CCR Rule, extensive permit applications for all CCR units (landfills and ash ponds) were submitted to Georgia EPD on or before November 22, 2018. These permit applications outlined significant and detailed engineering information about Georgia Power’s ash pond closure plans and landfill operations plans. The CCR permits issued by Georgia EPD will include the details of site-specific requirements that each facility must follow in order to close the ash ponds as well as to operate and close CCR landfills to comply with the more stringent Georgia CCR Rule. These CCR permits will under go 5-year permit reviews as required under the Georgia CCR Rule.

**Ash Pond Closure Compliance Strategy**

The Company’s compliance strategy includes permanently closing 29 ash ponds at 11 facilities across the state and ceasing placement of coal ash in ash ponds in 2019. The Company underwent significant work to determine the closure method and site-specific plan for each ash pond. The Company engaged with third-party engineering design firms as well as Southern Company Services to develop feasibility-level estimates for both closure method and use of advanced engineering methods to determine each site-specific strategy. The Company conducted a comprehensive review of design criteria and risk assessments. Each design is then evaluated based on implementation timeline and cost. The output of this process enables the Company to develop a comprehensive and cost-effective compliance strategy. Ash pond closure designs are certified by independent professional engineers following a detailed, site-specific engineering analysis. The engineering analyses included the consideration of multiple factors including but not limited to ash pond size, location, geology, safety and volume of material. These factors were evaluated, in combination with closure engineering methods that could be implemented safely, in compliance with the federal and state CCR rules, meet expected permit conditions, and minimize future risk and costs for the Company.

Georgia Power’s closure plans include removing the ash from 19 ash ponds located adjacent to lakes or rivers. Each closure is designed and will be managed to comply with federal and state CCR rules where the CCR from these ponds will be relocated to permitted landfills, or consolidated with other closing ash ponds on site. As discussed in Section 3.3, the Company is developing a center for beneficial use of harvested CCR to evaluate potential benefits. The Company’s strategy includes maximizing the amount of ash from these closed facilities that can be put into productive applications through beneficial reuse. This includes direct reuse from the ash ponds and also ensuring the future benefical reuse capability by ensuring permits issued by Georgia EPD allow for harvesting of ash stored in the Company’s CCR landfills. The remaining 10 ash ponds are being closed-in-place using advanced engineering methods. The site-specific advanced engineering methods will be designed to enhance the protection of groundwater, improve closure stability, and facilitate efficiencies in future maintenance of the unit. Methods selected and under evaluation include consolidating CCR to minimize the closed footprint, slurry walls, in-situ solidification/stabilization, accelerated dewatering, and cover system enhancements. Each closure is designed with purpose to: (1) protect water quality, (2) prevent post closure infiltration of water, (3) prevent future impoundment of water and sediment, (4) ensure slope stability that prevents the sloughing or movement of the final cover system, and (5) facilitate efficiencies for future maintenance of the CCR unit following closure.

As part of the ash pond closure process, the Company will develop comprehensive and customized plans to treat all water from the ponds during closure. This treatment and removal activity is known as "dewatering." The Company prepares and submits dewatering plans to Georgia EPD for approval in conjunction with the NPDES wastewater discharge permits, installs new water treatment systems designed for each site, and provides Georgia EPD and surrounding communities advanced notice prior to dewatering. Georgia Power’s efforts to dewater its ash ponds are well underway and results are posted to Georgia Power’s website and reported to the Georgia EPD. The Company's dewatering process treats the water from the ash ponds to ensure that it meets the requirements of each plant's wastewater discharge permit approved by the Georgia EPD and is protective of water quality standards. These water treatment systems have shown through demonstrated performance that they are effective and provide protection of receiving stream water quality. To date, the Company has submitted and received approval from Georgia EPD for five dewatering plans, three of which are in use. Additional dewatering plans will be required for all remaining projects, and will be submitted to EPD for review and approval prior to implementation. The dewatering activities occur under the direction of independent third-party licensed wastewater operators throughout the duration of each closure project. In addition, the company has also engaged independent, third-party contractors for effluent and receiving stream sampling, and accredited independent laboratories for analysis.

As mentioned above, these ash pond closure and advanced engineering methods are site-specific, which creates the need for an in-depth evaluation of site characteristics before and throughout the closure process to determine the most appropriate method for both initiating and progressing toward closure. Each closure design will be approved and regulated through permits issued and monitored by Georgia EPD.

While developing this comprehensive and cost-effective CCR compliance strategy, Georgia Power considered utilization of all available compliance options necessary to meet the deadlines in the CCR rules. At some plants, additional time for compliance may be necessary for the installation of controls or to complete closure activities in a manner that is compliant, cost-effective, as well as taking into consideration the multitude of other compliance and operational requirements. A summary of the Company’s closure strategy that follow the permits submitted to Georgia EPD is provided in Table 4.3-1.

**Table 4.3-1 CCR Strategy**

|  |  |  |  |
| --- | --- | --- | --- |
| **Plant** | **Impoundment/Landfill** | **Closure Method** | **Description** |
| Arkwright | LF (AP-1) | Closure by Removal to Permitted LF | AP-1 was closed in 2010 under EPD's Solid Waste Regulations. Under the new Georgia CCR Rule, AP-1 will be closed by removal to an on site landfill. Site restoration will be completed following CCR removal. |
| Arkwright | LF (AP-2DAS) | Closure by Removal to Permitted LF | AP-2 DAS was closed in 2010 under EPD's Solid Waste Regulations. Under the new state CCR rule, AP-2 DAS will be closed by removal to an on site landfill. Site restoration will be completed following CCR removal. |
| Arkwright | LF (AP-3/Monofill) | CCR Consolidation with Permitted Landfill | AP-3/Monofill was closed in 2010 under EPD's Solid Waste Regulations. AP-3/Monofill will be expanded to incorporate AP-1 and AP-2 DAS and closed in place. AP-3/Monofill is in post closure care. This post closure care will expand to include the new footprint and monitoring and maintenance will continue for the expanded unit (existing closed in place AP-3/Monofill, AP-1, and AP-2 DAS) in accordance with state and federal CCR rules. |
| Bowen | AP-1 | Advanced Close in Place with Liner | AP -1 will be closed in place following excavation of CCR to install a new liner system. The CCR within AP-1 will be excavated and consolidated into an approximately 144-acre fully-contained engineered structure (composite-lined and final-covered area) that will be constructed in the south-central portion of the current AP-1 approximatley 250 acre footprint. |
| Bowen | LF | Active LF/Close in Place | The landfill will be closed in place when permitted capacity is reached or when CCR disposal is no longer needed at the facility. |
| Branch | AP-A | Closure by Removal to Permitted LF | AP-A was closed by removal and consolidated with AP-E before the State CCR Rule was in effect. Site restoration (grading and vegetation) has been completed. Georgia Power submitted a Certification of Ash Removal from AP-A to EPD in 2018 to provide documentation of the AP-A closure. |
| Branch | AP-B, C, D | Closure by Removal to Permitted LF | AP-B, C, & D will be closed by removal to a new permitted onsite lined CCR landfill. Site restoration will be completed following CCR removal. |
| **Plant** | **Impoundment/Landfill** | **Closure Method** | **Description** |
| Branch | AP-E | Closure by Removal to Permitted LF | AP-E will be closed by removal to a new, permitted onsitelined CCR landfill. AP-E is regulated as a Category I dam under the Georgia Safe Dams Program. Closure design will include plans with restoration for removal of the dam from being regulated such that compliance requirements associated with maintaining a Category I dam will no longer be necessary. Site restoration will be completed following CCR removal. |
| Hammond | AP-1, 2, 4 | Closure by Removal to Permitted LF | AP-1, 2, and 4 will be closed by removal to a GPC-owned, off-site permitted landfill. Site restoration will be completed following CCR removal. |
| Hammond | AP-3 | Advanced Close in Place | AP-3 was closed-in-place with a geomembrane cover system in the second quarter of 2018. Advanced engineering methods are being evaluated and will be incorporated in the closure. |
| Hammond | LF (Huffaker Rd) | Active LF /Closure in Place | This landfill will be closed in accordance with Federal CCR Rule and the CCR permit that will be issued from the Georgia EPD. The landfill will be closed when permitted capacity is reached or when CCR disposal is no longer needed. |
| Kraft | AP-1 | Closure by Removal to Permitted LF | AP-1 was closed by removal to offsite permitted landfills. Site restoration (grading and vegetation) is complete. |
| Kraft | LF (Grumman Rd) | Inactive LF /Closure in Place | Grumman Road Landfill is an inactive landfill and is being closed in place in accordance with the current landfill permit. |
| McDonough | AP-1 | Advanced Close in Place | AP-1 was closed in place in 2017 with a geosynthetic cap cover system. Advanced engineering methods are being evaluated and will be incorporated into the closure. |
| McDonough | AP-2 | Closure by Removal | AP-2 has been closed by removal and consolidated with AP-1. Site restoration activities are forecasted to be complete in 2019. |
| McDonough | AP-3 & 4 | Advanced Close in Place | AP-3 & AP-4 are being consolidated and closed in place with a geosynthetic cap cover system. Advanced Engineering methods are being implemented. |
| **Plant** | **Impoundment/Landfill** | **Closure Method** | **Description** |
| McIntosh | AP-1 | Closure by Removal to Permitted LF | AP-1 will be closed by removal to a permitted on-site landfill. Site restoration will be completed following CCR removal. |
| McIntosh | LF3 | Closed in Place LF | This landfill was closed in 2008 and is in post-closure care. When issued, LF-3 will comply with EPD requirements defined in its permit. |
| McIntosh | LF4 | Active LF /Closure in Place | LF4 will be closed in place according to the permit issued from the EPD. LF4 considers closure when permitted capacity is reached or when CCR disposal is no longer needed. |
| Mitchell | AP-A, 1, 2 | Closure by Removal to Permitted LF | AP- A, 1, and 2 will be closed by removal of the CCR to an off-site permitted landfill. After CCR removal, the site will be restored. |
| McManus | AP-1 | Closure by Removal to Permitted LF | AP-1 is being closed by removal to an off-site permitted landfill. The site will be restored following CCR removal. |
| Scherer | AP-1 | Advanced Closure In Place | AP-1 will be closed in place with an engineered cap-cover system and by consolidating the CCR within the 550-acre ash pond to a smaller 330-acre footprint. Advanced engineering methods are being evaluated and will be incorporated in the closure. |
| Scherer | LF | Active LF /Closure in Place | The landfill will be closed in place according to the permit issued from the EPD. The landfill considers closure when permitted capacity is reached or when CCR disposal is no longer needed. |
| Wansley | AP-1 | Advanced Closure In Place | AP-1 will be consolidated into a smaller footprint and closed in place with an geosynthetic cap cover system. The footprint of the pond will be reduced from 343 acres to 138 acres. Advanced engineering methods are being evaluated and will be implemented in the closure. |
| Wansley | LF | Active LF /Closure in Place | This landfill will be closed in place according to the permit issued from the EPD. The landfill considers closure when permitted capacity is reached or when CCR disposal is no longer needed. |

|  |  |  |  |
| --- | --- | --- | --- |
| **Plant** | **Impoundment/Landfill** | **Closure Method** | **Description** |
| Yates | AP-1 | Closure by Removal & Consolidation | AP-1 was closed by removal to R6 and AP-B' and AP-3. Removal activities at AP-1 were completed in 2018. Site restoration activities will be completed and are planned for 2019. |
| Yates | AP-2 | Closure by Removal & Consolidation | AP-2 will be closed by removal to AP-B' and AP-3. Site restoration will be completed following CCR removal. |
| Yates | AP-3 | Advanced Closure In Place | AP-3 is currently being consolidated and will be closed in place with an engineered cap-cover system. Advanced engineering methods are being evaluated and will be incorporated in the closure. |
| Yates | AP-A | Closure by Removal & Consolidation | AP-A was closed by removal to AP-B' and AP-3. Removal and restoration activities at AP-A were completed in 2017. |
| Yates | AP-B | CCR Removal & Consolidation | AP-B is currently being closed by removal to AP-B' and AP-3. Site restoration will be completed following CCR removal. |
| Yates | AB-B' | Advanced Closure In Place | AP-B’ is being consolidated and will be closed in place with an engineered cap-cover system. Advanced engineering methods are being evaluated and will be incorporated in the closure. |
| Yates | AP-C | Inactive LF/ Closure In Place | R6 (inclusive of AP-C) is being closed in place according to the permit issued from the EPD |
| Yates | LF (R-6) | Inactive LF/Closure in Place |
| Yates | LF | Closed by Removal to Permitted Landfill and Beneficial Re-Used | The Landfill was closed by removal; the gypsum material was both beneficially reused and disposed to an off-site permitted landfill. Site restoration was complete and GPC is coordinating with EPD to obtain approval for the landfill closure. |

**Dry Ash Systems and Wastewater Treatment Systems to Replace Ash Ponds**

When ash ponds are closed, new dry ash handling systems and wastewater treatment systems will be necessary for compliance at operational plants. As discussed in section 4.2, these wastewater treatment systems are designed to meet not only our wastewater permit discharge requirements, but also the requirements of the ELG rule. As a result of the requirements of the ELG Rule and the CCR rules, the Company has developed a comprehensive strategy to address all waste streams, while maintaining reliable service to customers (see Table 4.2.2-1).

The implementation of this strategy ensures reliable electricity for customers during the significant construction work that must take place at fossil fuel-fired plants to accommodate the installation of new treatment systems for ash handling, FGD wastewater, and CCR wastewater that will allow the Company to proceed with the ash pond closure process. These efforts include conducting work when the plants are on planned outages or as customer demand allows operations to accommodate the work.

**Landfill Disposal and Beneficial Reuse**

Since ash ponds will no longer be used for ash handling, the Company will rely on Company-owned CCR landfills for the future disposal of CCR generated from coal-fired facilities when reuse opportunities are not available. Georgia Power will continue to rigorously manage and operate CCR landfills in compliance with CCR permits, the Georgia CCR Rule, and the Federal CCR Rule.

**REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED**

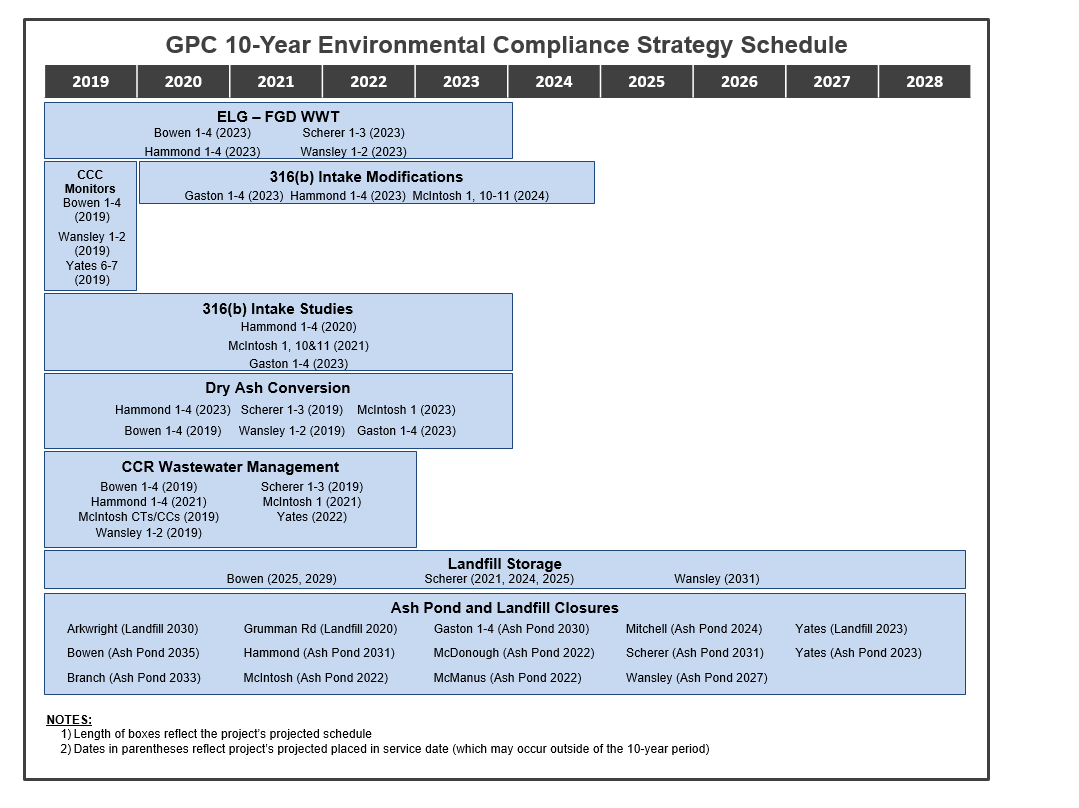
**Ongoing and Post Closure Requirements**

Throughout the ash pond closure process, Georgia Power is and will continue to monitor groundwater and regularly report the results to the Georgia EPD as well as post regular updates to the Company's website. Georgia Power has installed approximately 500 groundwater monitoring wells around its ash ponds and on-site landfills to actively monitor groundwater quality. Groundwater monitoring is being conducted in compliance with federal and state regulations. Following pond closure, groundwater will continue to be monitored as required under both the federal and state CCR Rule. Once closure is complete, post closure care will be implemented in accordance with the federal and state CCR rules.

In general, post closure care will include inspecting the closed ash pond to verify continued structural integrity, maintaining the integrity effectiveness of the final cover system for ash ponds closed in place, and maintaining the groundwater monitoring system.

**4.4 Strategy and Schedule**

The environmental strategy and schedule continues to evolve, even as state and federal requirements are being proposed and finalized. The 2018 GPC environmental strategy and schedule, resulting from the 2018 strategy review process, for all media are provided in Figure 4.4-1. The Company continues to review each schedule and update as applicable throughout implementation of this complex and multifacted strategy. Schedule changes that have occurred do not affect the Company’s ability to comply with applicable environmental requirements and timelines. The environmental compliance strategy schedule as shown in Figure 4.4-1 does not reflect the retirement of Plant Hammond and Plant McIntosh.

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**Figure 4.4-1 2018 Environmental Compliance Strategy Schedule**

**REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED**

For the land and water compliance schedule, **REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED**

In addition to those projects included in the schedule above, additional compliance obligations are possible as a result of new or revised future rules.

**4.5 Financial Summary**

Through 2017, Georgia Power has invested approximately $5.5 billion in capital projects to comply with applicable environmental statutes. Georgia Power’s annual totals were $0.3 billion, $0.2 billion, and $0.3 billion in 2017, 2016, and 2015, respectively. In Georgia Power’s Annual Report on Form 10-K for the year ended December 31, 2017, Georgia Power projected that base level capital expenditures to comply with existing statutes and regulations will be a total of approximately $1.2 billion from 2018 through 2022, with annual totals of approximately $0.5 billion, $0.1 billion, $0.2 billion, $0.2 billion, and $0.2 billion for 2018, 2019, 2020, 2021 and 2022, respectively. The environmental compliance capital as well as operating and maintenance (“O&M”) costs are recovered through the Environmental Compliance Cost Recovery (“ECCR”) tariff, established in the Georgia PSC’s final order in Docket 25060-U.

The Company’s compliance strategy, including potential unit retirement and replacement decisions, and future environmental capital expenditures will be affected by the final requirements of any new or revised environmental statutes and regulations that are enacted, including the proposed environmental legislation and regulations described; the cost, availability, and existing inventory of emissions allowances; and the Company’s fuel mix.

In addition to capital and O&M financial impacts from the installation of environmental controls, Title IV of the 1990 Clean Air Act and CSAPR both can financially impact the Company through SO2 and NOx emission allowances. The Company’s allowance purchase strategy is discussed below.

**4.5.1 Allowance Strategy**

Southern Company and Georgia Power manage allowance resources by balancing compliance with value. It is imperative to ensure sufficient allowances are available and allocated to the correct generating unit accounts to satisfy the requirements of the CAAA and CSAPR. The planning process outputs projected allowance needs over time for GPC. However, the volume of allowances surrendered for compliance will depend upon the individual unit operations realized within that compliance year. The Southern Company system, which functions as a centrally dispatched system, has a mechanism in place to track unit operations. At the end of a compliance period, any reallocation of allowances between or among units only takes place at the operating company level.

Value management focuses on optimizing the use of the allowances available to Georgia Power. The goal of value management is to plan for the ultimate disposition of allowances in a manner that will serve in the best interest of Georgia Power’s customers.

**4.5.2 CCR Asset Retirement Obligations**

In accordance with Financial Accounting Standards Board (“FASB”) Statement No. 143 and FASB Interpretation No. 47, Georgia Power is required to capture costs incurred for the legal obligations associated with the retirement of certain fixed assets. Expenditures associated with the closure and post closure care of CCR units under the federal and state CCR Rules are therefore reflected in the Company’s Asset Retirements Obligation (“ARO”) liabilities.

As a result, and as part of the ongoing strategy process, Georgia Power evaluated the costs connected with CCR AROs related to compliance with the federal and state CCR Rule requirements associated with CCR landfill closures, ash pond closures, and post closure care. The evaluation included project-specific engineering assessments, closure studies, constructability reviews, and various assumptions related to timing and methods for complying with CCR Rule closure requirements. Projected CCR unit closure costs and post closure care costs necessary to comply with the federal and state CCR Rules are identified as AROs and are included in the Selected Supporting Information section of Technical Appendix Volume 1.

Georgia Power will continue to comply with all applicable state and federal regulatory requirements and is continually seeking to increase appropriate beneficial uses of CCR. Georgia Power continues to evaluate these options and will consider market opportunities to determine the most cost-effective strategy, as evidenced by the ash beneficiation demonstration project.

**ECS-APPENDIX A**

**Acronyms/ABBREVIATIONS and Terminology**

|  |  |  |
| --- | --- | --- |
| **A/C** | Air-to-Cloth Ratio | |
|  |  | |
| **ACE** | Affordable Clean Energy | |
|  |  | |
| **ACI** | Activated Carbon Injection | |
|  |  | |
| **ALK** | Alkali Sorbent Injection | |
|  |  | |
| **ANPRM** | Advanced Notice of Proposed Rulemaking | |
|  |  | |
| **ARO** | Asset Retirement Obligation | |
|  |  | |
| **BACT** | Best Available Control Technology | |
|  |  | |
| **BART** | Best Available Retrofit Technology | |
|  |  | |
| **BAT** | Best Available Technology | |
|  |  | |
| **BO** | Biological Opinion | |
|  |  | |
| **BPT** | Best Practicable Control Technology | |
|  |  | |
| **BTA** | Best Technology Available | |
|  |  | |
| **CAA** | Clean Air Act | |
|  |  | |
| **CAAA** | Clean Air Act Amendments (of 1990) | |
|  |  | |
| **CaBr2** | Calcium Bromide | |
|  |  | |
| **CAIR** | Clean Air Interstate Rule | |
|  |  | |
| **CAMR** | Clean Air Mercury Rule | |
|  |  | |
| **CAVR** | Clean Air Visibility Rule | |
|  |  | |
| **CCOFA** | Close-Coupled Overfire Air | |
| **CCR** | Coal Combustion Residuals | |
|  |  | |
| **CCS** | Carbon Capture and Sequestration | |
|  |  | |
| **CEIP** | Clean Energy Incentive Program | |
|  |  | |
| **CEMS** | Continuous Emissions Monitoring System | |
|  |  | |
| **CERCLA** | Comprehensive Environmental Response, Compensation, and Liability Act | |
|  |  | |
| **CFS** | Concentric Firing System | |
|  |  | |
| **CO** | Carbon Monoxide | |
|  |  | |
| **CO2** | Carbon Dioxide | |
|  |  | |
| **COHPAC** | Compact Hybrid Particulate Collector |
|  |  |
| **COP** | Conference of Parties |
|  |  |
| **CMP** | Meeting of the Parties to the Kyoto Protocol |
|  |  | |
| **CPP** | Clean Power Plan | |
|  |  | |
| **CSAPR** | Cross State Air Pollution Rule | |
|  |  | |
| **CWA** | Clean Water Act | |
|  |  | |
| **CWIS** | Cooling Water Intake Structure | |
|  |  | |
| **CWWS** | Cylindrical Wedge Wire Screens | |
|  |  | |
| **DOE** | Department of Energy | |
|  |  | |
| **DSI** | Dry Sorbent Injection | |
|  |  | |
| **ECS** | Environmental Compliance Strategy | |
|  |  | |
| **ELG** | Effluent Limitations Guidelines | |
|  |  | |
| **EPA** | U.S. Environmental Protection Agency | |
| **EPCRA** | Emergency Planning and Community Right-to-Know Act | |
|  |  | |
| **EPD** | Georgia Environmental Protection Division | |
|  |  | |
| **EGU** | Electric Generating Unit | |
|  |  | |
| **EO** | Executive Order | |
|  |  | |
| **EPRI** | Electric Power Research Institute | |
|  |  | |
| **ESA** | Endangered Species Act | |
|  |  | |
| **ESP** | Electrostatic Precipitator | |
|  |  | |
| **FASB** | Financial Accounting Standards Board | |
|  |  | |
| **FGD** | Flue Gas Desulfurization | |
|  |  | |
| **FGMC** | Flue Gas Mercury Control | |
|  |  | |
| **FIP** | Federal Implementation Plan | |
|  |  | |
| **GHG** | Greenhouse Gas | |
|  |  | |
| **GPC** | Georgia Power Company | |
|  |  | |
| **GW** | Gigawatt | |
|  |  | |
| **HAP** | Hazardous Air Pollutant | |
|  |  | |
| **HCl** | Hydrogen Chloride | |
|  |  | |
| **HDPE** | High-Density Polyethylene | |
|  |  | |
| **IB** | Industrial Boiler | |
|  |  | |
| **ICR** | Information Collection Request | |
|  |  | |
| **IGCC** | Integrated Gasification Combined Cycle |
|  |  |
| **IPP** | Independent Power Producers |
|  |  | |
| **IRP** | Integrated Resource Plan | |
|  |  | |
| **LNB** | Low-NOX Burner | |
|  |  | |
| **LNCFS** | Low-NOX Concentric Firing System | |
|  |  | |
| **LNCFS I** | LNCFS + CCOFA | |
|  |  | |
| **LNCFS II** | LNCFS + SOFA | |
|  |  | |
| **LNCFS III** | LNCFS + CCOFA + SOFA | |
|  |  | |
| **LVW** | Low Volume Wastewater | |
|  |  | |
| **MACT** | Maximum Achievable Control Technology | |
|  |  | |
| **MATS** | Mercury and Air Toxics Standards | |
|  |  | |
| **MRCS** | Mercury Re-emission Control System | |
|  |  | |
| **MW** | Megawatt | |
|  |  | |
| **N2** | Nitrogen | |
|  |  | |
| **NAAQS** | National Ambient Air Quality Standards | |
|  |  | |
| **NCMCW** | Nonchemical Metal Cleaning Waste | |
|  |  | |
| **NGCC** | Natural Gas Combined Cycle | |
|  |  | |
| **NO2** | Nitrogen Dioxide | |
|  |  | |
| **NOX** | Nitrogen Oxide | |
|  |  | |
| **NPDES** | National Pollution Discharge Elimination System | |
|  |  | |
| **NSPS** | New Source Performance Standards | |
|  |  | |
| **NSR** | New Source Review | |
|  |  | |
| **OFA** | Overfire Air | |
|  |  | |
| **O&M** | Operating and Maintenance | |
|  |  | |
| **OMB** | Office of Management and Budget | |
|  |  | |
| **PJFF** | Pulse-Jet Fabric Filter | |
|  |  | |
| **PM** | Particulate Matter | |
|  |  | |
| **PM2.5** | Particulate Matter less than 2.5 micrometers in size | |
|  |  | |
| **PPA** | Power Purchase Agreement | |
|  |  | |
| **PPB** | Parts Per Billion | |
|  |  | |
| **PPM** | Parts Per Million | |
|  |  | |
| **PRB** | Powder River Basin | |
|  |  | |
| **PSC** | Georgia Public Service Commission | |
|  |  | |
| **PSD** | Prevention of Significant Deterioration | |
|  |  | |
| **PSES** | Pretreatment Standards for Existing Sources | |
|  |  | |
| **PSNS** | Pretreatment Standards for New Sources | |
|  |  | |
| **R&D** | Research and Development | |
|  |  | |
| **RACT** | Reasonably Available Control Technology | |
|  |  | |
| **RCRA** | Resource Conservation and Recovery Act | |
|  |  | |
| **RTR** | Risk and Technology Review | |
|  |  | |
| **SAB** | Science Advisory Board | |
|  |  | |
| **SCR** | Selective Catalytic Reduction | |
|  |  | |
| **SEGCO** | Southern Electric Generating Company | |
|  |  | |
| **SER** | Significant Emission Rate | |
|  |  | |
| **SIP** | State Implementation Plan | |
|  |  | |
| **SNCR** | Selective Noncatalytic Reduction | |
|  |  | |
| **SO2** | Sulfur Dioxide | |
|  |  | |
| **SO3** | Sulfur Trioxide | |
|  |  | |
| **SO­x** | Sulfur Oxides | |
|  |  | |
| **SOFA** | Separated Overfire Air | |
|  |  | |
| **SSM** | Startup, Shutdown, Malfunction | |
|  |  | |
| **T-Fired** | Tangential or tangentially fired | |
|  |  | |
| **TVA** | Tennessee Valley Authority | |
|  |  | |
| **TMDL** | Total Maximum Daily Load | |
|  |  | |
| **TSCA** | Toxic Substances Control Act | |
|  |  | |
| **TWS** | Traveling Water Screens | |
|  |  | |
| **UARG** | Utility Air Regulatory Group | |
|  |  | |
| **UNFCCC** | United Nations Framework Convention on Climate Change | |
|  |  | |
| **USWAG** | Utility Solid Waste Activities Group | |
|  |  | |
| **UWAG** | Utility Water Act Group | |
|  |  | |
| **VOC** | Volatile Organic Compound | |
|  |  | |
| **WIIN Act** | Water Infrastructure Improvements for the Nation Act | |
|  |  | |
| **WOTUS** | Waters of the U.S. | |
|  |  | |
| **WRC** | Water Research Center | |
|  |  | |
| **WQS** | Water Quality Standards | |

**ECS-APPENDIX B**

**envrionmental Control Alternatives**

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**environmental Control Alternatives**

**I. Selective Catalytic Reduction (SCR)**

SCR technology involves the catalytic reaction of ammonia, which is injected into the flue gas, with NOX to produce molecular nitrogen (N2) and water vapor. These reactions take place across multiple layers of catalyst in the SCR reactor and generally result in a NOX reduction capability of 85 to 90 percent depending upon the particular application. Theoretically, the NOX and ammonia react in the presence of SCR catalysts. However, side reactions that produce undesirable byproducts can occur between ammonia and sulfur trioxide (SO3) in the flue gas.

The SCR operating temperature ranges from 550 to 750°F. As a result, the SCR system normally is located in a high-dust configuration between the boiler economizer flue gas outlet and the air preheater flue gas inlet where the above temperature range normally occurs. Prior to entering the reactor, ammonia is injected into the flue gas at a sufficient distance upstream of the reactor to provide for adequate mixing of the ammonia and flue gas. The quantity of ammonia injected is adjusted to maintain the desired NOX reduction level (within design limits). NOX emissions are reduced in direct proportion to the quantity of ammonia injected up to an ammonia-to-NOX ratio of approximately 0.80. Above this value (and as the activity of the catalyst declines with age), some of the ammonia can escape the SCR reactor as ammonia slip. This ammonia can react with small quantities of SO3 present in the flue gas to form ammonium bisulfate, which can foul and/or increase the corrosion potential for downstream equipment.

**II. Selective Noncatalytic Reduction (SNCR)**

SNCR employs chemical injection of ammonia or urea directly into the boiler at a flue gas temperature between 1,600 and 2,100°F. In this temperature range, which is typically near the top of the boiler close to the furnace exit or in the convective pass, the reagent reacts with NOX to form nitrogen and water without the use of a catalyst to promote the reaction.

As with SCR, the ammonia slip constraint imposes a limit on the maximum amount of NOX that can be removed with the SNCR process. Because the process is so temperature sensitive, the ability to follow boiler load becomes critical when constrained by ammonia slip limits. Advanced SNCR systems use retractable injection lances that improve load-following control for the process. These lances use a “jet curtain” to provide better cross-sectional coverage and rotation of the lance allows for better response to process signals such as boiler load or furnace temperature.

Application of SNCR to utility-scale boilers is highly site specific. Generally, SNCR is capable of 15- to 40-percent NOX removal, consistent with a 5-parts per million (ppm) ammonia slip constraint. Removal levels above 40 to 50 percent are difficult to achieve due to the high-ammonia slip that is produced, the stringent requirements placed on the distributions for injected reagents, and the narrow temperature window required for the reaction.

One particular benefit of SNCR as compared to SCR is that capital cost is limited due to the absence of catalyst and the associated reactor vessel. However, potentially much higher ammonia slip levels cause increased downstream problems. In addition, the difficulty in meeting temperature and distribution requirements makes implementation of the technology difficult on many boilers, especially on a large-scale boiler (typically greater than 300 MW). SNCR systems also generally require more reducing agent for a given NOX reduction than do SCR systems since part of the reducing agent can be oxidized at the higher injection temperature, representing an initial loss of reagent. Furthermore, the oxidation product is often NOX, requiring additional reagent (ammonia) to remove the NOX formed via oxidation.

**III. Fuel Switch to Natural Gas**

Existing coal plants can be partially or completely converted to burn natural gas instead of coal. Since natural gas contains very little sulfur, sulfur oxide emissions can be reduced to a level that is below that produced by flue gas desulfurization. Natural gas does not have constituents that remain after combustion to create ash, unlike coal where the natural minerals are transformed in the coal combustion process. Trace metals, which are present in coal, are largely absent from natural gas and so they are not emitted from natural gas combustion.

Nitrogen oxides or NOx results from both fuel chemistry and from the air used in combustion. Therefore, a natural gas conversion does not automatically eliminate emissions of nitrogen oxides. The level of NOx in such a conversion is determined by the boiler design plus the presence and design of low NOx firing systems (see the next section). Well designed and operated low NOx firing systems on coal boilers can produce similar NOx emissions to those seen in natural gas conversions.

Natural gas steam electric boilers are not subject to the MATS Rule, which also allows up to an annual 10% heat input from coal. Thus, a coal boiler which is switched to natural gas could still use coal as a backup fuel and not be subject to MATS requirements.

The choice of switching a coal boiler to natural gas is complex, with many factors to be considered. The location of natural gas pipelines, the availability of natural gas in either summer or winter, the energy diversity of the generating fleet, the other environmental regulations surrounding coal ash and water treatment, and local ambient air attainment status all have to be considered. Switching a coal unit to natural gas can produce lower emissions and – if natural gas prices remain low – produce affordable electricity for customers.

**IV. Low-NOX Burners and Overfire Air**

Low-NOX Burner (“LNB”) is a generic term for a burner designed to combust the fuel while reducing the amount of NOX that is formed. Since there are several different firing arrangements for oil- and coal-fired boilers, there are several different types of LNBs.

NOX is formed during combustion from either the nitrogen in the fuel or the air. NOX formed from nitrogen in air requires high-flame temperatures and because of this, is usually referred to as thermal NOX. Some fuels, particularly coal and oil, contain small amounts (2 percent or less) of nitrogen as a chemical constituent. When these fuels are burned, this fuel nitrogen can be oxidized in the flame-producing NOX, which is referred to as fuel NOX. Thus, coal and oil can form NOX from the thermal NOX and the fuel NOX mechanisms, but the fuel-nitrogen pathway is by far the predominant one. Since natural gas contains no fuel nitrogen, thermal NOX *only* is formed, explaining why natural gas flames have much lower NOX levels than coal.

LNBs for coal and heavy oil are designed to reduce NOX by allowing the fuel nitrogen to be released from the fuel in a region with low-oxygen concentration. Most of the fuel nitrogen can then react to molecular nitrogen (N2, the main constituent of air). High temperatures are needed to extract most of the nitrogen from the fuel and low-oxygen concentrations are also necessary to prevent the fuel nitrogen from being oxidized. This approach is known as air staging because a portion of the combustion air must be introduced later in the combustion process to form this low-oxygen reduction zone. Wall-fired LNBs achieve this end by an aerodynamic trick in each burner’s flame while, in a tangentially fired furnace, a portion of the secondary air is diverted above the flame (i.e. OFA), producing a low-oxygen zone in the entire lower furnace.

LNBs for wall-fired units are typically dual-register burners. By using two separate registers for the secondary air, some of the secondary air is used to initiate and stabilize the flame (with inner-register air), while most of the secondary air is directed by the outer register to bypass the initial flame and then mix with the flame after the fuel nitrogen is released and converted to N2. Different manufacturers use different hardware implementations for this process, but the general technical concept is much the same. Most also use some means of ensuring the flame stays attached to the tip of the burner. A stable, attached flame is a lower NOX producer than either an unstable flame or a detached flame.

LNBs for tangentially fired boilers serve to assist in NOX reduction by supporting the air staging used for the major NOX reduction technique. There are different manufacturing designs for low NOX burners for these plants that control the mixing and direction of the combustion air relative to the coal-air mixture injected into the furnace. Most tangentially-fired boilers rely heavily on OFA in addition to low NOX burners.

OFA is a very effective method to reduce NOX emissions. In fact, the most general approach to lowering NOX produced in oil or coal combustion is to create a main flame zone that is deficient in oxygen and is known as a reducing atmosphere. If the temperature can be held high in this reducing zone, the majority of the fuel nitrogen can be driven from the fuel. Since little oxygen would be present, this fuel nitrogen then reacts to form N2, which is the main constituent of air. OFA is the air that is added to finish the combustion process started in the combustion zone. In a vertical flow typical of boilers, the reducing zone is the main combustion zone. OFA is added above this flame zone, thus the name “overfire” air.

Up to approximately 30 percent of the total air needed for combustion may be supplied as OFA. As the amount of OFA increases, the NOX emissions of the combustion process decrease, up to a point. Any further increase in the amount of OFA above this point will cause the NOX emissions to increase. The practical limitations on the amount of OFA that can be used are:

* Stability of the main flame
* Corrosion of the metal steam tubes
* Production of carbon monoxide
* Increases in the amount of unburned carbon that escapes the furnace and is collected with the fly ash

OFA is a part of most of the tangentially fired NOX control systems described.

**V. Powder River Basin (PRB) Coal**

PRB coal is a subbituminous coal mined primarily from seams in the PRB located in Wyoming and Montana in the western United States. Reasons for broadening the use of PRB coal include favorable economics and the added benefits of lower fuel-bound nitrogen and sulfur components that enhance the ability of generating units to minimize NOX, as well as SO2 emissions. Additional NOX reductions are realized because of the lower combustion flame temperature brought about by the higher moisture content in PRB coal. With this increase in moisture content come lower heat contents (heating values), suppression of mill outlet temperatures below design minimums, possible loss of generation due to unit-load deratings, and potential increased forced outage rates during the peak season. Increased heat rate and higher operating and maintenance costs are also usually associated with a switch to PRB coal from bituminous coal. Compacting the stockout piles and increased housekeeping around transfer points are considerations to alleviate potential problems with self-heating of the higher-reactivity PRB coal. Soot blower maintenance and increased boiler inspection may be required to maintain/sustain boiler operation. ESP capacity may also be affected and additional fields or flue gas conditioning may be required to adequately collect the PRB fly ash. The impact on SCR catalyst activity of elevated levels of alkali earth metals in PRB fly ash is also a concern, but has been seen as a controllable factor.

**VI. Flue Gas Desulfurization (FGD)**

Flue gas from coal- and oil-fired boilers will contain sulfur oxides produced from any sulfur in the fuel. FGD is any process that removes these sulfur oxides, primarily SO2 with a small amount of SO3. These sulfur oxides (SOX), can range from 0.3 percent of the flue gas by volume down to several hundred parts per million. The two main types of processes are characterized by either wet- or dry-process chemistry.

As implied by the category, wet processes collect the SOX by treating the flue gas with a water-based solution or slurry. One typical design the utility industry uses is a spray tower module where the flue gas flows up the tower and a series of nozzles spray an alkaline solution into the flue gas. The common chemical used in wet FGDs is limestone and the solids produced by modern designs are predominantly calcium sulfate, or gypsum. This gypsum can either be sold as a pre-cursor to wallboard, used in cement or concrete, or used for agricultural purposes or be disposed of in a landfill or pond. The wet processes are very efficient and remove 80 to 99 percent of the SO2 in flue gas with 95 percent removal typical.

Dry processes inject an alkaline slurry into the flue gas stream in a spray dryer followed by a particulate control device. The spray dryer is a unit where the hot flue gases are contacted with the wet alkaline spray that absorbs the SO2. The hot flue gas evaporates the water and leaves a dry residue that can then be captured with the fly ash, typically in a baghouse. ESPs are normally not used behind a spray dryer because of the high resistivity of the calcium residues that are added to the fly ash. The residue also contains a mixture of calcium sulfite/sulfate, along with the fly ash from the fuel. This waste is not suitable for other uses and must be disposed of in a landfill or pond. Historically, dry scrubbing is considered to typically remove 75 to 90 percent of the SO2 in flue gas.

**VII. Dry Sorbent Injection (DSI)**

Dry sorbent injection is a technology that can help reduce acid gas emissions. DSI systems remove HCl and other acid gases through two basic steps. In step one, a powdered sorbent is injected into the flue gas where it reacts with the HCl. The sorbents most commonly associated with DSI are trona (sodium sesquicarbonate, a naturally occurring mineral mined in Wyoming), sodium bicarbonate, and hydrated lime.

For step two, the compound is removed by a downstream PM control device such as an ESP or a baghouse. Baghouses are generally more effective (when combined with DSI) than ESPs, with respect to overall HCl reduction. For modeling purposes, EPA estimates a DSI system with a baghouse is expected to achieve 90% removal of HCl, while a DSI system with an ESP only achieves 60% removal, although actual performance will vary by individual plant.

DSI systems generally do not require significant capital expenses, but may rely on significant quantities of sorbent to operate effectively, which increases the operating costs. Waste disposal for DSI may also be a significant variable cost, while the waste products from an FGD system can be sold as feedstock for industrial processes. In addition, DSI's potential effectiveness is limited to certain types of plants. Because of the amount of sorbent needed, DSI will likely be implemented most often at plants that are 300 megawatts or less and burn low-sulfur coal.

DSI systems can also significantly reduce SO2 emissions through the same process as HCl removal.

**VIII. Baghouses**

Baghouses are filter devices that remove solid particles from flue gas streams by passing the gases through a fabric, and thus collecting the particles. While baghouses can either operate as a standalone control device or in conjunction with other particulate capture devices, all of Georgia Power’s baghouses are located downstream of the plant’s electrostatic precipitators. This configuration – a baghouse located downstream of an existing ESP – was patented by EPRI and is known as a Compact Hybrid Particulate Collector (“COHPAC”).

The basic COHPAC concept is to place a pulse-jet fabric filter (“PJFF”) downstream of an existing ESP to serve as a “polishing” or performance-upgrading unit. The flue gas enters the PJFF and passes through the fabric where the fly ash particles are filtered from the gas. The particles are collected on the outside of the fabric and the resulting dust layer is cleaned from the bags by air pulses (and thus, the nomenclature: pulse-jet fabric filters). Since the ESP removes a significant amount of the particles from the gas stream the flue gas reaching the baghouse has a significantly reduced dust load. The residual electrical charge from particle charging in the ESP and low-dust loading enables the COHPAC PJFF to operate at an air-to-cloth ratio (A/C) in the 6 to 12 range. (A/C is a ratio of the amount of gas to the amount of fabric present.) A typical full-scale PJFF without an upstream ESP must operate at A/C ratios of 4 or below, allowing the physical size of a COHPAC PJFF to be up to one-fourth the size of a normal PJFF, which reduces the cost significantly.

**IX. Activated Carbon Injection and Alkali Sorbent Injection**

ACI for mercury control involves the addition of powdered activated carbon to flue gas streams where it adsorbs vapor phase mercury. This powdered material is made by “cooking” low rank coals with steam and temperature to activate the surface, generating a highly reactive product that acts like a chemical sponge. Once injected into the flue gas, the activated carbon (and adsorbed mercury) must be collected in a particulate collection device. The applications of this technology are either (1) ahead of an ESP or (2) downstream of an existing ESP but upstream of a high ratio (COHPAC) baghouse.

The first configuration mentioned above has been tested under various conditions with wide ranging results depending on contact time, fuel type, ESP size, and process conditions. Typically, due to rapid removal of the carbon in the ESP and limited contact time with the flue gas, these applications typically achieve lower removal of mercury than carbon into baghouses. Injecting activated carbon upstream of an ESP remains useful as needed for mercury control to complement the passive co-benefits of SCR and FGD.

The second application, injection into a COHPAC baghouse, is an EPRI patented technology known as TOXECONTM. This process attempts to limit the co-mingling of fly ash and activated carbon by collecting a high fraction of fly ash in the ESP before injecting the activated carbon. Furthermore, because the activated carbon is collected on bag surfaces (where it can stay from several minutes to hours), the TOXECONTM process can typically achieve much higher removal rates than ESP injection (up to 90 percent), again depending on fuel type and process conditions. The primary drawback to this process is the added financial requirement in building a COHPAC baghouse, which significantly affects the overall cost of mercury removal.

In either application, the mercury removal effectiveness of activated carbon injection can be enhanced when burning coals with higher sulfur content (e.g. non-PRB coals) by employing ALK, typically hydrated lime injection, ahead of the activated carbon injection. Typically, the hydrated lime used for ALK is less expensive than the activated carbon, so the use of ACI plus ALK is a more economical process than ACI alone for a given mercury capture target.

**X. Chemical Injection for Mercury Removal (Halogen Injection)**

One relatively inexpensive way to capture and remove mercury from a flue gas stream is through the injection of chemical additives. Combustion of PRB coal produces primarily elemental mercury, which is insoluble in a wet FGD system. The presence of relatively high levels of elemental mercury in PRB flue gas is due to low levels of chlorine in the PRB coal, relative to other coals. High chlorine concentrations in many coals contribute to higher levels of oxidized mercury at the FGD inlet. Calcium bromide or calcium chloride can be injected to oxidize mercury in PRB and other low chlorine coals, so that the mercury can be captured in a flue gas desulfurization FGD or baghouse.

**XI. Mercury Re-emission Controls System (MRCS)**

Wet FGDs are effective at removing oxidized mercury. However, as the captured mercury may remain in a dissolved form in the FGD slurry in the vessel, the FGD may from time to time re-emit the mercury that was captured from the flue gas. This can cause increased levels of mercury emissions out of the stack. The addition of additives into the FGD slurry can help prevent the occurrence of mercury re-emission by encouraging the mercury dissolved in the slurry to precipitate into a solid. Typically, additives injected into the FGD slurry to address mercury re-emission are less expensive than the activated carbon injected upstream of the ESP or baghouse for mercury control; therefore, if mercury re-emission is observed in a given FGD, an installed MRCS can be a cost-effective means of removing mercury in the FGD.

**XII. Containment and Control Technologies for Ash Storage Areas**

Several technologies are available to control and close ash storage areas. The most common technologies include liners, caps, slurry walls, sheet pile walls, grouting, and *in situ* solidification and stabilization. A brief description of each technology is provided below.

**Advanced Engineering Methods (AEMs)**

AEMs are the technologies that will be implemented in conjunction with close in place pond closures to enhance the protection of groundwater. AEMs are implemented for the following reasons:

* To compliment closure and reduce the potential for groundwater impacts
* To improve or enhance the stability of the closure, where applicable
* To assist in minimizing long-term O&M efforts

**Closure Footprint Reduction**

Ash ponds closed in place may involve consolidating ash into a smaller footprint. This promotes closure improvements by reducing the potential for groundwater impacts as well as reduces long term O&M associated with maintaining the closed facility.

**Liners**

A liner is a layer of impermeable or low-permeability material placed at the bottom of ash storage facilities, which prevents ash leachate from entering soil and groundwater. Liners can be constructed of compacted natural material (such as clay), synthetic materials (such as High-Density Polyethylene (“HDPE”)), or composite materials (combination of synthetic and natural materials). Regulations generally require liners under new ash storage areas.

**Caps**

A cap is a layer of impermeable or low-permeability material placed on top of ash storage areas, to preventsurface water infiltration and resulting leachate. By preventing water movement through the ash, environmental impacts are prevented or reduced. As with liners, caps can be constructed of natural materials (for example, compacted clay), synthetic materials (HDPE), or a composite. Capping may be used in conjunction with liners or barrier walls to encapsulate a material in place.

**Slurry Walls**

Slurry walls are subsurface walls constructed in trenches excavated down to the top of a relatively low-permeability layer, such as clay or bedrock. The trench is filled with a slurry of materials that forms an impermeable barrier to prevent/minimize the migration of groundwater within the area. Slurry materials can include various mixtures of soil, bentonite clay, and/or cement.

**Sheet Pile Walls**

Sheet piling includes interlocking wood, concrete, or steel sectors driven into the ground or forced into pre-dug trenches, usually to the top of a relatively impermeable layer (for example, clay or bedrock). As with slurry walls, sheet pile walls form an impermeable barrier to prevent/minimize the migration of groundwater. Steel sheet pilings are the most reliable and most commonly used. Sheet piling is often used as a temporary measure of containment while dewatering or excavation, or while other containment is constructed.

**Grout Curtains**

A grout curtain is a method of sealing gaps in subsurface geology by injection of grout to fill voids in fractured rock, or to consolidate soil by filling the pore space. The grout material may be a Portland cement mix or any fluid material that hardens, such as a resin or sodium silicate. The grout material is injected as a pressurized fluid through holes drilled into the ground, generally in rows. Under ideal conditions, the injected fluids harden to create a relatively impermeable barrier, similar to a wall, in the subsurface.

**In situ Solidification/Stabilization**

Solidification/stabilization describes the technique of solidifying soil or waste material (e.g., a sludge), to reduce the potential for groundwater interaction. Solidification refers to the addition of a binder to produce a solid. Stabilization refers to the addition of a chemical agent to convert the soil or waste material to a more chemically stable form. Some additives, such as Portland cement, produce both physical and chemical changes. Large augers or equipment with rotary blades are used to mix the additives with contaminated soil or waste material.

**XIII. Cooling Water Intake Screen Technology**

Inclined traveling water screens (“TWS”) and cylindrical wedge wire screens (“CWWS”) will generally be the preferred water screen technologies. Both screens will allow debris handling and the design is also adaptable to minimize impingement and entrainment. Screen wash systems for the TWS and airburst systems for the CWWS can maintain screen cleanliness to an acceptable level. If needed, continuous fish and debris handling systems can also be designed to work with the TWS. As needed, fish-return technologies are also available.

**XIV. Water Cooling Technologies**

Cooling water systems are generally placed into two catgeories: either wet systems, which use water as the cooling medium, or dry systems that utlize air. Wet cooling systems withdraw water to absorb heat via indirect contact with steam in a condenser. These wet cooling systems are divided into two types, based on the manner in which the cooling water is used: once-through and closed-cycle systems with cooling towers or ponds. Unlike once-through systems that continuously draw fresh cold water from a large water source, closed cycle systems recirculate the same cooling water in a continuous loop through the condenser, with only very small amounts of water being withdrawn from a source to replace the water that is lost due to evaporation, drift, and blowdown in the cooling tower.

Because of the relative simplicity, the capital and operating costs for once-through systems are less than those for closed-cycle systems with a cooling tower. Once-through systems can also include helper cooling towers to reduce thermal load at the water discharge point, but these systems do not reduce water withdrawals. Conversion to a closed-cycle cooling water system reduces water withdrawals about 95%. Because of this, implementation of a closed-cycle system with a cooling tower is one potential method of minimizing impingement and entrainment. However, consumptive use of water will be increased from use of cooling towers and approximately 75% of the cooling water withdrawn is not returned to source but is lost to the atmosphere via evaporation. Also, conversion to a closed-loop system needs to be considered carefully, since it may mean that all the materials in the loop (*e.g.*, condenser tubes) will be exposed to water that may be significantly more aggressive than with a once-through water system.

Dry cooling systems transfer heat to the atmosphere without the use of water. Steam leaving the turbine is piped to an air-cooled, finned-tube condenser. Dry cooling has an adverse effect on power plant efficiency, requires a large area of land, and is more expensive than wet cooling. A hybrid system incorporates elements of both wet and dry cooling systems in an attempt to maximize the benefits of each. Few large-scale applications of hybrid systems exist in the United States and the cost is commensurate with that of dry cooling. Neither a dry nor a hybrid cooling system is considered an economically or technically viable option for retrofit of an existing generating unit in the Southeast.

**XV. Water Research and Conservation Center**

Originally developed in 2012 through collaboration with EPRI and Southern Company, WRC at Plant Bowen has provided a venue for independent performance evaluations of technologies to address water use, withdrawal, consumption, treatment, and recycling throughout the power generation process. In addition to providing electric generating companies with independent testing and evaluation of current and cutting-edge technologies, the WRC has generated new information regarding current and future regulatory compliance issues related to water withdrawal, use, and discharge restrictions. Testing at the WRC has and continues to inform technological strategies for achieving cost-effective environmental compliance with a focus on the following key areas:

* Cooling tower and advanced cooling systems
* Zero liquid discharge systems
* Moisture recovery
* Wastewater treatment
* Solid waste landfill management
* Carbon technology water questions
* Water management modeling

In partnership with EPRI, Southern Research Institute, and other industry partners, Southern Company R&D and Georgia Power are expanding the Water Research Center at Plant Bowen in 2019 to become the Water Research and Conservation Center with locations at Plants Bowen and McDonough-Atkinson. The center at Plant Bowen will maintain its focus on researching technologies to maintain compliance with current and future environmental regulations, while continuing the testing and evaluation of pilot systems that are nearing commercialization.

The new center at Plant McDonough-Atkinson will promote long-term solutions and advancements in power plant cooling systems leading to reduced freshwater withdrawal and consumption as well as improved plant efficiency while optimizing total cost and energy generation. This center will provide a venue with the necessary infrastructure, like the one at Plant Bowen, that the Company and project partners can use in developing and testing technologies to reach these goals.

**XVI. Ash Handling Methods**

The ELG and federal and Georgia CCR rules affect coal ash handling and disposal methods at most Georgia Power units. While some units have dry ash handling capability, most use wet sluicing to ponds or settling basins as either the primary method of disposal or as back-up to the dry handling equipment. In order to comply with the federal and Georgia CCR rules and ELG Rule requirements, Georgia Power is closing all ash ponds and will stop sluicing coal ash in 2019. Significant construction is underway at each generating plant to modify coal ash handling systems, such as pneumatic dry ash handling equipment, remote submerged chain conveyors and ash coolers. These systems are utilized in conjunction with additional storage silos and collection systems to facilitate disposal or reuse options.

**XVII. Landfills**

As additional ash storage is needed beyond the useful life of existing landfills or as the federal and Georgia CCR rules may require ash ponds to be closed before their useful life is spent, landfill disposal is the likely alternative for long term ash disposal. This technology has been implemented for ash and gypsum at several Georgia Power facilities. This requires regulatory permitting, hydrogeologic/geologic studies, and large amounts of available property. In addition, a leachate collection and pumping system would be installed to manage any landfill leachate collected.

**XVIII. Wastewater Treatment**

As discussed in section 4.2, the ELG Rule requires additional treatment of the wastewater discharged from FGD systems to remove from the water certain trace metals that the FGD removed from the flue gas. Most of the metals may be treated to the anticipated limits by relatively conventional physical and chemical treatment, such as flocculation, coagulation, precipitation and filtration. However, the selenium limits in the rule are very low and the best performing removal method is biological treatment, which has not been demonstrated to consistently meet these limits. Southern Company continues to research alternative treatment technologies that are more effective, economical and reliable.

LVW is another category of waste stream that requires new treatment systems in the future due to the closure of ash ponds. LVW is currently collected from many sources throughout the plant and conveyed to the ash pond for co-treatment with ash transport water. The new site-specific treatment facilities could include physical-chemical treatment systems, utilizing lined settling basins, tanks, clarifiers, pH adjustment, and associated pumps, piping and equipment.

**ECS-APPENDIX C**

**HIGH-LEVEL AND LOW-LEVEL RADIOACTIVE WASTE STORAGE**

**PLANTS HATCH AND VOGTLE**

Georgia Power’s affiliate, Southern Nuclear Operating Company (“Southern Nuclear”) safely operates and maintains Plants Hatch and Vogtle in accordance with industry standards and regulatory requirements. Southern Nuclear is dedicated to maintaining the highest standards for safely handling radioactive waste to protect the public, the environment, and its workers.

**High-Level Radioactive Waste (“HLRW” - spent fuel)**

Dry Cask Storage:

Plant Hatch and Plant Vogtle– currently store spent fuel in underwater spent fuel pools and some above ground in dry casks on concrete pads until such time that the federal government licenses and builds a permanent disposal facility which can accept this waste.

These above ground dry casks (also known as Independent Spent Fuel Storage Installations or ISFSI) are engineered to assist in cooling the spent fuel bundles while providing adequate shielding for the protection of plant employees as well as the surrounding community and environment.

Southern Nuclear, as well as the nuclear industry, has a strong commitment to the Yucca Mountain repository as a scientifically safe and appropriate long-term solution for used nuclear fuel. The issues surrounding Yucca Mountain are political, not scientific. At the same time, the nuclear industry has adopted a used fuel management strategy that supports the research, development, and demonstration of projects to close the nuclear fuel cycle (i.e., reprocessing). It is important to note that even with reprocessing, the Yucca Mountain repository is necessary to dispose of the byproducts of nuclear fuel.

**Low-Level Radioactive Waste (“LLRW” - trash, tools, scrap, filtering media, irradiated hardware, etc.)**

Similar to the nuclear power industry, over 95 percent of the LLRW generated by Plant Hatch and Plant Vogtle continues to be buried at the Energy Solutions burial site in Clive, UT.

The remaining LLRW cannot be buried at Clive, UT. In the past, it was buried at the Barnwell, SC burial facility, but that site is no longer accessible to most states including Georgia.

Plant Hatch and Plant Vogtle will store this remaining LLRW on the site where it was generated inside concrete shields on a concrete pad. Contract companies that can properly process, reduce, and/or dispose of Class B and C waste are being evaluated. There is a burial site in Andrews, TX that will accept “B & C” LLRW.

Southern Nuclear in conjunction with the nuclear industry is always working towards reducing the generation of radioactive waste.