Review and Comments on
Reasonable Progress Four-Factor Analyses
Evaluated as Part of the Georgia Regional Haze Plan
for the Second Implementation Period

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July 25, 2022

Prepared for
National Parks Conservation Association and Sierra Club

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I. Introduction

The Clean Air Act's regional haze provisions require states to adopt periodic, comprehensive revisions to their implementation plans for regional haze on 10-year increments to achieve reasonable progress towards the national visibility goal. The deadline for the regional haze plan revision for the second implementation period to be submitted to EPA was July 31, 2021.[1] As part of the comprehensive revisions to their regional haze plan, states must submit a long-term strategy that includes enforceable emission limits and other measures as may be necessary to make reasonable progress towards the national visibility goal.[2]

To that end, in June of 2022, the Georgia Environmental Protection Division (GEPD) made available its plan for addressing reasonable progress toward the national visibility goal for Class I areas.[3] GEPD identified three facilities for which it required four-factor analyses of regional haze controls.[4]

The following summarizes GEPD's proposed reasonable progress requirements for the three facilities that submitted four-factor analyses:

- Georgia Power – Plant Bowen found that no additional controls were reasonable. Plant Bowen will limit the Steam Generating Units (Emission IDs SG01, SG02, SG03 and SG04) to the Mercury and Air Toxics (MATS) SO2 emission limit of 0.20 lb/MMBtu based on a 30-day operating rolling average.
- International Paper (IP) – Savannah will no longer be allowed to burn coal in the No. 13 Power Boiler (PB13).
- Brunswick Cellulose is required to eliminate the firing of tire derived fuel (TDF) in the No. 4 Power Boiler, and to limit the firing of No. 6 fuel oil to times of natural gas curtailment with additional fuel oil firing allowanced during adverse bark/wood fuel conditions to give the facility operational flexibility. The facility will be limited to 15 tons per year of SO2 emissions from firing fuel oil outside of periods of natural gas curtailment.[5]

The four factors that must be considered in determining appropriate emissions controls for the second implementation period are as follows: (1) the costs of compliance, (2) the time necessary for compliance, (3) the energy and non-air quality environmental impacts of compliance, and (4) the remaining useful life of any source being evaluated for controls. EPA has stated that it anticipates the cost of controls being the predominant factor in the evaluation of reasonable progress controls and that

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[1] 40 C.F.R. §51.308(f).

[2] 40 C.F.R. §51.308(f)(2)(i); 42 U.S.C. § 7491(b)(2). Under the Clean Air Act, state implementation plans must include "include enforceable emission limitations and other control measures, means, or techniques . . . , as well as schedules and timetables for compliance, as may be necessary or appropriate to meet the applicable requirements of this chapter." 42 U.S.C. § 7491(a)(2)(A). An emission limitation is a "requirement" that "limits the quantity, rate, or concentration of emissions of air pollutants on a continuous basis, including any requirement relating to the operation or maintenance of a source to assure continuous emission reduction." *Id*. § 7602(k).

[3] June 24, 2022 Georgia's State Implementation Plan for Regional Haze (PREHEARING) (hereinafter referred to as "June 2022 Draft Georgia Regional Haze Plan").

[4] *Id.*, Executive Summary at iii.

[5] June 2022 Draft Georgia Regional Haze Plan, Executive Summary at iii.

the other factors will either be considered in the cost analysis or not be a major consideration. Specifically, the remaining useful life of a source is taken into account in assessing the length of time the pollution control will be in service to determine the annualized costs of controls. If there are no enforceable limitations on the remaining useful life of a source, the expected life of the pollution control is generally considered the remaining life of the source. In addition, costs of energy and water use of regional haze controls such as wet and dry flue gas desulfurization (FGD) at a particular source are considered in determining the annual costs of these controls, which means that the bulk of the non-air quality and energy impacts are generally taken into account in the cost effectiveness analyses as is the remaining useful life of a unit. The length of time to install controls is not generally an issue of concern for pollution controls, as FGD systems, dry sorbent injection (DSI), selective catalytic reduction (SCR), and selective noncatalytic reduction (SNCR) all can be and have been installed within three to five years of promulgation of a requirement to install such controls. In any event, EPA's August 20, 2019 regional haze guidance states that, with respect to controls needed to make reasonable progress, the "time necessary for compliance" factor does not limit the ability of EPA or the states to impose controls that might not be able to be fully implemented within the planning period; more specifically, when considering the time necessary for compliance, a state may not reject a control measure because it cannot be installed and become operational until after the end of the implementation period."

This report provides comments on the four-factor analyses for the two of the three facilities evaluated by GEPD, Georgia Power's Plant Bowen and International Paper – Savannah. In addition, this report provides comments on two additional facilities for which GEPD should have conducted four-factor analyses: Georgia Power's Plant Scherer and Georgia Power's Plant Wansley.

In brief, this report finds the following issues with the four-factor analyses for these facilities and/or provides the following recommendations for the other facilities:

Georgia Power – Plant Bowen

- The SO2 control measure of switching from high sulfur Illinois Basin coal to low sulfur Powder River Basin should be considered cost effective at $6,424/ton of SO2 removed. GEPD's cost effectiveness is less than the cost effectiveness thresholds being used by other states in their regional haze plans such as Oregon, Colorado, Nevada, New Mexico, and Arizona. The annual costs would likely be even lower if Georgia Power had considered the addition of new coal pulverizers which would lower or eliminate the derate of the generating capacity that would occur with the change to the lower heating value Powder River Basin coal. Moreover, a switching from bituminous to subbituminous coal could significantly reduce NOx emissions, which is an added benefit of this control measure that GEPD must take into account.
- If GEPD does not find that switching to Powder River Basin coal is justified, then any SO2 emissions limit that it imposes for the Plant Bowen units should be lower than its proposed 0.20 lb/MMBtu SO2 limit. Each Plant Bowen unit should be able to meet a 30-day average SO2 limit of no higher than 0.17 lb/MMBtu.
- GEPD must consider the adoption of a NOx emission limit of 0.07 lb/MMBtu applicable year-round for each Plant Bowen unit, because the actual emissions data show that the units do not appear to be operating their SCR systems year-round. Imposition of a 0.07 lb/MMBtu rolling 30-day average NOx limit could reduce NOx emissions by an average 2,400 tons per year.

International Paper – Savannah

- GEPD has proposed to require the removal of coal as a permitted fuel for Power Boiler 13 as a reasonable progress measure. However, International Paper has already ceased burning coal in Power Boiler 13 since 2017.
- GEPD failed to evaluate any NOx controls for Power Boiler 13 to achieve reasonable progress.
- With respect to the SO2 control cost analyses for Power Boiler 13, the analyses overestimated costs of both a circulating dry scrubber (CDS) and dry sorbent injection (DSI) by including an unjustified high retrofit factor, by including costs for a landfill expansion that appear to be overstated (especially for CDS), and by taking into account owner's costs and Allowance for Funds Used During Construction (AFUDC) which are not allowed in the EPA's Control Cost Manual methodology.
- Further, the cost analysis of CDS at Power Boiler 13 understated the SO2 removal capabilities by only assuming 90% control when CDS systems can achieve up to 98% SO2 removal.
- Revised cost analyses addressing some of these issues show that a CDS system would be a very cost effective SO2 control at Power Boiler 13 at a cost effectiveness of $3,790/ton to reduce SO2 by 3,900 tons per year on average. Thus, GEPD should adopt a reasonable progress requirement for Power Boiler 13 that reflects installation of a CDS system.

Georgia Power – Plant Scherer and Plant Wansley

- Despite the Plant Scherer and Plant Wansley units being equipped with top level SO2 and NOx controls, including wet scrubbers and SCR, the units are not consistently achieving emission rates that reflect the pollutant removal capabilities of these controls.
- GEPD must consider adopting emission limits for these units to reflect continual operation and optimization of their SO2 and NOx controls. For SO2 at these plants, GEPD should evaluate removing permit exemptions from the permit condition that requires 95% SO2 removal to ensure more continuous compliance with the 95% removal requirement. Alternatively, GEPD should impose a long term SO2 limit reflective of continuous operation and optimization of the SO2 controls at these units: that is an annual SO2 limit of 0.01-0.02 lb/MMBtu for the Plant Scherer units and an annual limit no higher than 0.13-0.14 lb/MMBtu at the Plant Wansley units.
- GEPD must consider the adoption of a NOx emission limit of 0.07 -0.08 lb/MMBtu applicable year-round for each Plant Scherer and Plant Wansley unit, because the actual emissions data show that the units do not appear to be operating their SCR systems year-round. Imposition of a 0.08 lb/MMBtu rolling 30-day average NOx limit at each of the Plant Scherer units could reduce NOx emissions by an average of 2,400 tons per year compared to the 2017-2021 average NOx emissions from Plant Scherer Units 1-3.[6] Requiring the Plant Wansley Units 1 and 2 to meet a NOx emission limit in the range of 0.07-0.08 lb/MMBtu could reduce annual emissions by approximately 150 to 260 tons per year from 2017-2021 average annual NOx emissions.

Below I provide my comments on these issues.

[6] Plant Scherer Unit 4 ceased operations in 2021. *See* https://www.flpublicpower.com/news/jea-reducing-carbon-emissions-with-closure-of-plant-scherer-coal-fired-unit

II. Georgia Power Company - Plant Bowen

Plant Bowen consists of four coal-fired electrical generating units (EGUs). The four units began operation between 1971-1975. The units have wet FGDs for SO2 control, specifically Chiyoda jet bubbling reactors, which were installed in 2008 at Units 3 and 4, in 2009 at Unit 2, and in 2010 at Unit 1. For NOx control, the units have low NOx burners and SCR. SCR was installed at Units 1 and 2 in 2001, and at Units 3 and 4 in 2003. The units all have cold-side electrostatic precipitators (ESPs) for particulate control. Despite the Plant Bowen units being equipped with top level air pollution controls, the units are not consistently achieving emission rates that reflect the pollutant removal capabilities of these controls. The table below shows the maximum and average 30-boiler operating day average SO2 and NOx rates for each Bowen Unit 1-4 over 2017-2021 to illustrate this point.

Table 1. Plant Bowen Units 1-4: Maximum and Average 30-Boiler Operating Day (30-BOD) Average SO2 and NOx Emission Rates Over 2017-2021[7]

Plant Bowen Unit	Max SO2, 30-BOD Avg, lb/MMBtu	Average SO2 30-BOD Avg, lb/MMBtu	Max NOx, 30-BOD Avg, lb/MMBtu	Average NOx 30-BOD Avg, lb/MMBtu
1	0.17	0.13	0.38	0.11
2	0.15	0.13	0.39	0.13
3	0.19	0.15	0.50	0.12
4	0.33	0.14	0.30	0.11

Georgia Power assumed 2019 emissions were reflective of 2028 emissions for the Plant Bowen units.[8] The 2019 SO2 and NOx emissions from the Plant Bowen units are provided in the table below.

Table 2. Plant Bowen Units 1-4 2019 SO2 and NOx Emissions (Which Georgia Power Assumed for 2028 Emissions)[9]

Plant Bowen Unit	SO2, tons per year	NOx, tons per year
1	3,026	1,994
2	1,778	1,029
3	1,749	874
4	2,678	1,835
Total	9,231	5,732

Compared to the most recent five years of emissions for Plant Bowen, 2019 SO2 emissions were higher than the 2017-2021 plantwide average SO2 of 8,324 tons per year and 2019 NOx emissions were lower than the 2017-2021 plantwide average NOx of 6,607 tons per year.

Three SO2 control options were evaluated for Plant Bowen Units 1-4: coal switching from Illinois Basin coal to Powder River Basin (PRB) coal, coal switching from Illinois Basin coal to Central Appalachian coal

[7] Calculated from data reported to EPA's Air Markets Program Database for 2017-2021, attached as Ex. 1.
[8] October 2021 Georgia Power Plant Bowen Regional Haze Four-Factor Analysis at 8.
[9] Based on emissions data reported to EPA's Air Markets Program Database.

(CAPP), and installation of dry FGD scrubbers.[10] GEPD did not propose to require any additional pollutant control measures for Plant Bowen, except that GEPD has proposed to require that Plant Bowen limit Units 1-4 to the MATS SO2 limit of 0.20 lb/MMBtu.[11] GEPD also did not provide any evaluation of control measures to reduce NOx emissions from Plant Bowen. The following provides comments on the evaluation of switching from Illinois Basin coal to PRB coal, on GEPD's proposed SO2 reasonable progress emission limits, and on control measures that GEPD should consider in order to reduce NOx emissions from the Plant Bowen units.

A. Comments on Analysis of Switching to 100% Powder River Basin Coal

The Plant Bowen units burn Illinois Basin (IB) coal which has a very high sulfur content. Based on an evaluation of the uncontrolled SO2 emission rates of the various coals shipped to Plant Bowen using EPA's AP-42 emission factors, I calculate a weighted average uncontrolled SO2 emission rate ranging from 3.99 lb/MMBtu to 4.17 lb/MMBtu over the past five years.[12] In contrast, PRB coal is much lower in sulfur content and typically has uncontrolled SO2 emission rates of 0.80 lb/MMBtu or lower.[13] Thus, with the existing wet scrubbers at each Bowen unit, a switch to PRB coal could result in a significant reduction in SO2 emissions from each unit.

GPED claimed that switching to Powder River Basin coal would result in a derate of the Bowen units: "A capacity derate of around 27% or greater would be expected using current unit equipment to process PRB coal at the same rate as current IB coal operations. The 27% derate was calculated based on the heat content of the PRB coal (8,800 Btu/lb) in comparison to IB coal (12,002 Btu/lb)."[14]

Georgia Power took into account the costs of an expected derating with a shift to PRB coal, and explained how it took into consideration the costs for the 27% derate with a switch to PRB coal as follows:

> The first indirect cost listed for switching to PRB coal for Plant Bowen Units 1-4 is the capacity penalty cost associated with the derate to unit capacities. Plant Bowen Units 1-4 provide capacity value by supporting system reliability and by avoiding costs associated with replacement capacity that would be required to meet customer peak demands and reserve margin requirements in the absence of such Plant Bowen units. Without these units, Georgia Power would have to procure short-term and long-term replacement capacity in order to restore Georgia Power and the Southern Company system to a comparable level of reliability that the system currently holds. The cost of replacement capacity in any year is assumed to be at either a market rate or the cost of new construction depending on whether Georgia Power has a projected capacity need in such year without Plant Bowen Units 1-4.

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[10] June 2022 Draft Georgia Regional Haze Plan at 208.
[11] *Id.* at 210-211.
[12] Based on data in the Energy Information Administration's Coal Data Browser, Shipments to Bowen attached as Ex. 2.
[13] Georgia Power assumed 0.80 lb/MMBtu uncontrolled SO2 with PRB coal. October 2021 Georgia Power Plant Bowen Regional Haze Four-Factor Analysis at pdf page 103.
[14] June 2022 Draft Georgia Regional Haze Plan at 209.

> The $51 million annualized cost of the estimated 27% derate of Plant Bowen Units 1-4 is therefore the annualized difference between the net present value of (1) the maximum capacity of the units on IB coal times the cost of replacement capacity in each year of the study period and (2) the maximum capacity of the units on PRB coal times the cost of replacement capacity in each year of the study period.[15]

Georgia Power cites to Technical Appendix A1.3-1 of its October 2021 four-factor submittal for calculations and supporting documentation for these calculations, but that Appendix does not appear to be not part of the publicly available four-factor analysis. Since this was the bulk of the cost of this control option, GEPD must make the underlying calculations publicly available for review.

Georgia Power took the costs for the estimated 27% derate into account in the cost analysis by calculating the net present value of derates to be $709 million, for which it then determined an annualized cost of derates of $51.7 million based on a 6.04% "firm-specific" interest rate and a life of control equipment (which is not stated but appears to be 30-years).[16] It is not clear why the company did not take the cost of purchasing electricity due to a derate as an operational expense, based on the current cost of purchasing electricity. Instead, it appears that Georgia Power took into account the future cost of purchasing electricity as essentially a capital expenditure for which it assumed a 6.04% rate of return.

In addition, although a 27% derate with a switch to PRB coal was assumed, Georgia Power stated "the level of unit capacity derate does not impact the annual SO_2 emissions reduction since the analysis assumes that the 2019 baseline annual heat input is achievable at this derated unit capacity with an increased amount of operating time."[17] This does not make sense to assume that a switch to 100% PRB coal would incur electricity purchase costs of $51 million per year while also assuming that the Plant Bowen units would increase operating time and electricity generation with a switch to PRB coal. By assuming the plant would burn the same heat input of coal with a switch to PRB coal by operating more hours but also assuming a 27% derating and the need to purchase electricity, there is a mismatch in the cost analysis. For example, the company assumed costs to purchase electricity as well as increased costs for PRB fuel purchases and operating costs (assuming same heat input of fuel purchased) but did not take into account the income from new sales of electricity due to the additional operating hours.

Further, Georgia Power did not quantify or evaluate the capital costs that could be made to each unit to reduce or eliminate the derate with the switch to PRB coal. The company acknowledged that the project derate could potentially be reduced by increasing coal throughput capacity with additional coal pulverizers.[18] The capital costs of additional coal pulverizers would likely be much lower than the net present value of $709 million of the capacity penalty cost calculated by Georgia Power,[19] and thus switching to Powder River Basin coal (along with adding coal pulverizers) could be more cost effective than calculated by Georgia Power.

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[15] October 2021 Georgia Power Plant Bowen Regional Haze Four-Factor Analysis at 15-16.

[16] October 2021 Georgia Power Plant Bowen Regional Haze Four-Factor Analysis at 17 and at Appendix B, pdf page 102 of report (Table A1.3).

[17] *Id.* at 15.

[18] *Id.*

[19] *Id.* at Appendix B, Table A1.3.

Regardless of these issues, the cost effectiveness of switching from the current Illinois Basin bituminous coal to lower sulfur Powder River Basin subbituminous coal should be considered as cost effective at GEPD's stated costs of $6,424/ton.[20] This is lower than the cost effectiveness thresholds being used by other states in their regional haze plans for the second implementation period. For example, Oregon, Colorado, and Nevada are using a cost effectiveness threshold of $10,000/ton.[21] New Mexico's threshold is $7,000 per ton.[22] Arizona is using a cost threshold of $6,500/ton.[23] GEPD stated that the cost of switching to PRB coal would be unreasonable at $6,424/ton.

Moreover, there is at least one other benefit that would be realized by switching from Illinois Basin to PRB coal. Specifically, this switch could result in significantly lower NOx emission rates. EPA's presumptive BART emission limits from its BART guidelines identify the presumptive NOx limit at tangentially -fired boilers that burn bituminous coal based on use of combustion controls alone (i.e., low NOx burners and overfire air, which the Bowen boilers are all equipped with) as 0.28 lb/MMBtu, whereas the presumptive BART limit at tangentially-fired boilers with combustion controls that burn subbituminous coal is listed as 0.15 lb/MMBtu.[24] That reflects a 46% decrease in NOx that could be realized at the Plant Bowen units from switching coals, assuming that the Bowen units' SCRs achieve the same level of NOx removal efficiency as they are currently achieving. Based on Georgia Power's assumption that 2019 emissions reflect 2028 projected emissions and assuming the switch to PRB coal would reduce NOx by 46%, 2,637 tons of NOx could be reduced per year with the coal switch. Taking into account both SO2+NOx reduced from switching to PRB coal (i.e., 7,482 tons of SO2 removed plus 2,637 tons of NOx removed), the cost effectiveness of switching to PRB coal would be $4,749/ton of SO2+NOx removed.[25] This significant decrease in NOx emission rates, which is also a source of regional haze, must be taken into account in evaluating the control of switching to Powder River Basin coal to reduce SO2 emissions and should weigh heavily in favor of requiring this cost-effective control as a reasonable progress control measure.

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[20] June 2022 Draft Georgia Regional Haze Plan at 208.

[21] *See*, e.g., September 9, 2020 letter from Oregon Department of Environmental Quality to Collins Forest Products, at 1-2, available at https://www.oregon.gov/deq/aq/Documents/18-0013CollinsDEQletter.pdf; Colorado Department of Public Health and Environment, In the Matter of Proposed Revisions to Regulation No. 23, November 17 to 19, 2021 Public Hearing, Prehearing Statement, at 7, available at https://drive.google.com/drive/u/1/folders/1TK41unOYnMKp5uuakhZiDK0-fuziE58v; Nevada Division of Environmental Protection, Nevada Regional Haze State Implementation Plan for the Second Planning Period at 5-6 (June 22, 2022 Draft), available at https://ndep.nv.gov/uploads/documents/1_all_sip_chpts_pn_draft.pdf.

[22] *See* NMED and City of Albuquerque, Regional Haze Stakeholder Outreach Webinar #2, at 12, available at https://www.env.nm.gov/air-quality/wp-content/uploads/sites/2/2017/01/NMED_EHD-RH2_8_25_2020.pdf.

[23] *See* Arizona Department of Environmental Quality, State Implementation Plan Revision: Regional Haze Program (2018-2028), June 3, 2022 Proposed, Appendix C at 45, available at https://static.azdeq.gov/aqd/haze/az_regional_haze_proposed_sip_20220603.pdf.

[24] 40 C.F.R. Part 51, Appendix Y, Table 1 Presumptive NOx Emissions Limits for BART-eligible Coal-Fired Units.

[25] Based on GEPD's stated annualized cost of switching to PRB coal of $48,059,482 per year. June 2022 Draft Georgia Regional Haze Plan at 208.

B. Comments on GEPD's Proposed SO2 Emission Limits for the Plant Bowen Units

Rather than requiring a switch from Illinois Basin coal to Powder River Basin coal to significantly reduce both SO2 and NOx emissions, GEPD has proposed to require a 0.20 lb/MMBtu, 30-day average SO2 limit for each Plant Bowen unit with exemptions for startup and shutdown.[26] As shown in Table 1 above, actual operating data shows that the Bowen units can achieve lower 30-boiler operating day average SO2 emission rates than a 0.20 lb/MMBtu SO2 limit and that no exemptions for startup or shutdown are warranted. A review of actual 30-boiler operating day average emission rates[27] based on emissions data reported to EPA's Air Markets Program Database from 2017 to 2021 reveals the following:

- Bowen Unit 2 did not have any 30-day average SO2 emission rates greater than 0.15 lb/MMBtu.
- Bowen Unit 1 did not have a 30-day average rate above 0.17 lb/MMBtu.
- With the exception of some 30-day averaging periods in 2017 due to one day of very high SO2 emissions out of the past five years, Bowen Unit 4 did not have 30-day average rates above 0.17 lb/MMBtu.
- Bowen Unit 3's maximum 30-day average SO2 rate was the highest of the four units at 0.19 lb/MMBtu over 2017-2021 but is still below 0.20 lb/MMBtu.
- The average 30-day average SO2 rates at each Bowen unit are at or below 0.15 lb/MMBtu.

This data shows that 1) a lower SO2 limit of 0.15 lb/MMBtu is a justifiable SO2 emission limit for each Plant Bowen unit, and 2) no exemption is needed for 30-day average SO2 limit for the Bowen units for startup and shutdown. At most, the Bowen units should not be subject to a limit any higher than 0.17 lb/MMBtu, as each unit has consistently been able to comply with such a limit (including Unit 3 which met a 0.17 lb/MMBtu 30-day average SO2 emission rate 93% of the time over 2017-2021). Imposing a lower SO2 emissions limit than 0.20 lb/MMBtu would lock in the current SO2 emission rates and ensure the wet FGD systems are being properly operated and maintained.

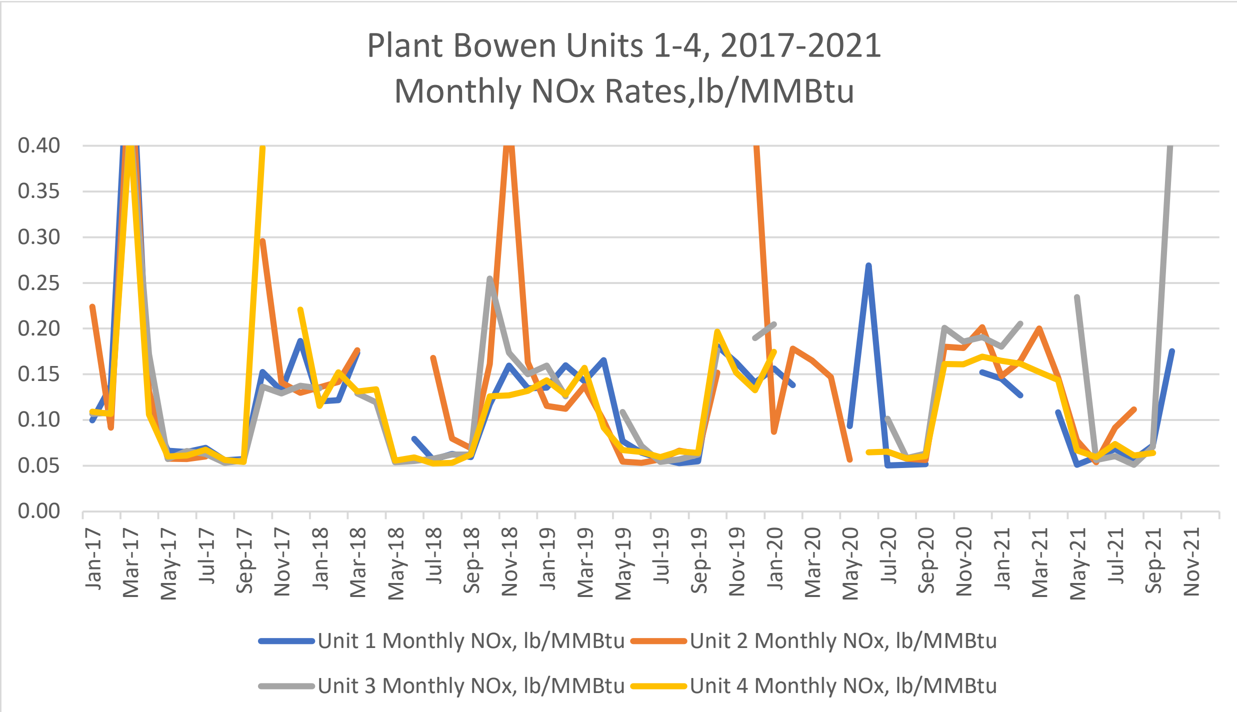
C. GEPD Must Adopt Reasonable Progress Requirements that Ensure Year-Round Operation of the SCR Systems at Each Bowen Unit.

GEPD did not evaluate any control options for NOx emissions from the Plant Bowen units. The Bowen units are all equipped with low NOx burners, separated overfire air, and SCR. Although Bowen Units 1-4 have very effective NOx controls, the units do not consistently reduce NOx emissions to the maximum extent practicable. A review of monthly NOx emission rates at each Plant Bowen unit as reported to EPA's Air Markets Program Database shows that the units appear to operate the SCR most optimally during the ozone season and, during other times of the year, either the SCR is not operated to minimize NOx to the extent practicable or not operated at all. This is shown in the chart below.

[26] June 2022 Draft Georgia Regional Haze Plan at 211.

[27] *See*. Ex. 1, Spreadsheet with Plant Bowen Daily 2017-2021 SO2 and NOx Emissions Evaluation.

Figure 1: Plant Bowen Units 1-4, Monthly NOx Emission Rates Reported to EPA's Air Markets Program Database



A review of the Plant Bowen Title V permit shows that the permit has NOx emission limits that only apply during the May – September ozone season and those emission limits offer a lot of flexibility in the required NOx emission rates. Specifically, the permit imposes a 7-power plant NOx emission limit of 32,355.8 tons per ozone season (May 1 through September 30), which includes the NOx emissions from Plant Scherer Units 1-4, Plant Bowen Units 1-4, Plant Branch Units 1-4, Plant Hammond Units 1-4, Plant McDonough Units 1-2, Plant Wansley Units 1-2, and Plant Yates Units 1-7.[28] However, several of these plants and units have shut down entirely or have converted to gas. Ozone season NOx emissions from the remaining units over 2020-2021 (i.e., Bowen, Scherer, Wansley, and Yates Units 6 and 7 (which are now gas-fired units)) ranged from 3,425 to 4,667 tons per ozone season. Thus, this 7-unit NOx emission limit will not ensure that NOx emissions from the Plant Bowen units are maintained, nor will the limit ensure that the SCR systems are operated and maintained for optimal NOx removal.

The Plant Bowen Title V permit also has individual unit NOx limits that only apply during the ozone season as follows of 0.07 lb/MMBtu applicable on a rolling 30-day averaging period at each Bowen unit.[29] If any unit does not comply with these limits, then the Plant Bowen units must comply with a 30-day average NOx limit of 0.13 lb/MMBtu averaged over the Plant Bowen, Wansley, and Yates units during the ozone season, and they must comply with a 30-day average 7-plant NOx emission limit of 0.18 lb/MMBtu.[30] However, these emission limits do not reflect the NOx capabilities of the Bowen units' NOx controls. A review of ozone season NOx emission rates at Plant Bowen Units 1-4 shows that the

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[28] GEPD, Bowen Steam-Electric Generating Plant, Air Quality-Part 70 Operating Permit No. 4911-015-0011-V-04-0, Condition 3.2.4.
[29] *Id.*, Conditions 3.4.7, 3.4.8, 3.4.9, and 3.4.10.
[30] *Id.*, Conditions 3.4.11 and 3.4.12.

average of each unit's 30-boiler operating day average NOx emission rate over the ozone seasons of the past five years (2017-2021) is 0.08-0.09 lb/MMBtu.[31] And a review of the 30-day average NOx emission rates over 2017-2021 shows that Plant Bowen Units 1-4 had 30-day average NOx emission rates at or below 0.08 lb/MMBtu for 75% of the time during the ozone season. Thus, the NOx emission limits in the current Title V permit do not reflect the optimal operation of the NOx controls at each unit including the SCR. Clearly, the Bowen units' SCRs are capable of high NOx removal efficiencies, but the SCRs are not always operated to achieve those NOx removal efficiencies.

Thus, GEPD must evaluate the readily implementable control option of establishing a 30-boiler operating day average NOx emission limit that reflects operation of the SCR year-round and that reflects the capability of the SCR systems. At the very minimum, GEPD should impose a 30-boiler operating day average NOx emission limit of no higher than 0.07 lb/MMBtu at each Plant Bowen unit. Given that GEPD has imposed 0.07 lb/MMBtu NOx limits in the Title V permit for Plant Bowen, presumably GEPD has found that Bowen Units 1-4 can meet a NOx rate of 0.07 lb/MMBtu on a rolling 30-day average basis. Based on the 2017-2021 average emissions, the requirement to consistently meet a 0.07 lb/MMBtu NOx emission limit with the existing NOx controls currently installed at each Plant Bowen unit would result in significant NOx emissions reductions, as shown in the table below.

Table 3. Average Annual NOx Emission Reductions from 2017-2021 Average NOx Emissions if a 0.07 lb/MMBtu 30-Day Average NOx Emission Limit Was Imposed on Each Bowen Unit

Bowen Unit	NOx Reduction at 0.07 lb/MMBtu Emission Limit, tpy
1	465
2	583
3	723
4	668
Total	**2,439**

For these reasons, GEPD must consider the adoption of NOx emission limits applicable year-round for each Plant Bowen unit as a readily implementable NOx control that could significantly reduce NOx emissions from the plant. On average, the requirement for each Bowen unit to meet a 0.07 lb/MMBtu NOx emission limit would reduce annual NOx emissions from the facility by about 46%. This significant emission reduction could be achieved at no capital cost but with the operational expense of increased operation of the SCR system and thus would surely be cost effective.

III. International Paper – Savannah Mill

The International Paper -Savannah Mill is located in Savannah, Georgia. GEPD states that there are four SO2 emission units at the facility: The No. 13 Power Boiler (PB13), the No. 15 Recovery Furnace (RF15), the No. 15 Recovery Furnace Smelt Dissolving Tank (RF10), and the No. 7 Lime Kiln (LK07). GEPD states that RF15, RF10, and LK07 are small sources of SO2 emissions that emit in total less than 30 tons per

[31] *See* Ex. 1, Spreadsheet with Plant Bowen Daily 2017-2021 SO2 and NOx Emissions Evaluation, at tabs for each unit during the ozone season.

year, and GEPD decided to focus its analysis of controls on PB13 which emits approximately 4,000 tons per year of SO2.[32]

According to International Paper's 2022 Four Factor Analysis, PB13 ceased firing fuel oil and coal in the boiler in the 2015-2017 timeframe, and the company requested that these fuels be removed from the list of permitted fuels in its December 2019 Title V permit application.[33] The company also stated that it installed load-bearing natural gas burners and also optimized combustion controls at PB13. All of these actions are stated to be based on requirements of 40 C.F.R. Part 63, Subpart DDDDD (otherwise known as the "Boiler MACT").[34]

A review of the current Title V permit for the International Paper- Savannah Mill shows that PB13 is currently allowed to burn biomass (bark), pulverized coal, natural gas, non-condensable gases, and condensate stripper off-gases.[35] Thus, the Title V permit has not yet been updated to not allow the burning of coal in PB13, even though International Paper stated that it stopped burning coal in PB13 in 2017.[36] International Paper indicates the following recent annual SO2 emissions of PB13 for the years 2018 and 2019 and its projected emissions for 2028. Based on the company's statement that coal-firing ceased in 2017, these actual SO2 emissions should not reflect any coal-firing in the power boiler.

Table 4. International Paper – Savannah Power Boiler 13 Actual SO2 Emissions and Projected 2028 Emissions[37]

Emission Unit	2018 SO2 Emissions, tpy	2019 SO2 Emissions, tpy	Projected 2028 SO2 Emissions, tpy
No. 13 Power Boiler	4,252	3,911	4,082

According to the company, the 2028 emissions are based on anticipated production, fuel, and non-condensable gas (NCG) firing scenarios.[38] The company also stated that the majority of SO2 emissions from the boiler are from combustion of NCGs that contain sulfur compounds and that the other fuels used (natural gas and biomass) are low sulfur fuels.[39]

GEPD has proposed to require the removal of coal as a permitted fuel for PB13 as a reasonable progress measure, claiming the removal of coal as a fuel would reduce SO2 emissions by 2,662 tons per year with no costs.[40] GEPD's representation of this reasonable progress control is misleading because International Paper has already ceased burning coal in PB13 since 2017. Also, for GEPD to indicate there were no costs associated with the cessation of coal burning ignores the fact that the company installed load bearing natural gas burners and possibly had associated costs because the boiler did not previously

[32] June 2022 Draft Georgia Regional Haze Plan at 202-203.
[33] International Paper, Regional Haze Rule Four-Factor Analysis for the International Paper Savannah Mill, November 2020, Revised June 2022, at 1-9.
[34] *Id.*
[35] GEPD Permit No. 2631-051-0007-V-30-0, July 15, 2015, at 3.
[36] International Paper, Regional Haze Rule Four-Factor Analysis for the International Paper Savannah Mill, November 2020, Revised June 2022, at 1-9.
[37] *Id.* at 1-3 (Table 1-1).
[38] *Id.* at 1-7.
[39] *Id.* at 1-8.
[40] June 2022 Draft Georgia Regional Haze Plan at 204.

burn natural gas. GEPD's estimate of 2,662 tons per year of SO2 reduced from the cessation of coal-burning also was not explained or documented. GEPD's estimated SO2 reduction does not reflect a reduction from 2028 projected SO2 emissions because those projections were based on 2018-2019 actual SO2 emissions and the company stated that PB13 no longer burned coal after 2017. Thus, GEPD's claimed SO2 reductions from its reasonable progress measure do not reflect any reduction from International Paper's 2028 SO2 emission projections for PB13. GEPD should thus evaluate SO2 controls for Power Boiler 13 more thoroughly. GEPD also did not evaluate any NOx controls for PB13. GEPD must also evaluate NOx controls for PB13 to achieve reasonable progress.

A. Comments on the SO2 Control Analyses for Power Boiler No. 13

International Paper evaluated two control options for PB13: a circulating dry scrubber (CDS) and dry sorbent injection (DSI). Although the company used EPA's Retrofit Cost Analyzer to estimate costs for these controls, there are several issues with the company's cost analysis that were not adequately documented and justified and that would inflate the costs of these controls. Those deficiencies are described below.

1. A 1.5 Retrofit Factor Was Not Justified for Either CDS or DSI.

International Paper assumed a 1.5 retrofit factor for both CDS and DSI without providing any documentation or justification. The company states this retrofit factor was used because "an engineering study has not been performed, space constraints exist, and production could be lost due to an extended Mill outage or unexpected delays."[41] This speculative and vague discussion is not sufficient documentation to justify applying a 1.5 retrofit factor to the cost of controls.

The company had a prior site-specific acid gas control cost analysis done in 2014, but the company did not rely on the 2014 site-specific analysis because it claimed that the fuel and emissions profile have changed since 2014.[42] Regardless, the 2014 site-specific acid gas controls analysis would be useful to review for comparison to the assumptions on which the company relied in using EPA's retrofit cost analyzer to estimate costs of control, especially pertaining to retrofit difficulty. GEPD should request the 2014 cost analysis conducted by Black & Veatch for PB13 and make it available to the public.

Without any site specific documentation, a 1.5 retrofit factor has not been justified for installation of a circulating dry scrubber at PB13, and such a high retrofit factor would not be justified for installation of DSI. Further, a high retrofit factor for CDS systems is not likely justified because CDS systems are known for their compact footprint.[43] In addition, for the installation of CDS at PB13, the existing ESP would no

[41] International Paper, Regional Haze Rule Four-Factor Analysis for the International Paper Savannah Mill, November 2020, Revised June 2022, at 2-9.
[42] *Id.* at 2-10.
[43] *See,* e.g., Babcock & Wilcox Circulating Dry Scrubber (CDS) at https://www.babcock.com/home/products/circulating-dry-scrubber-cds/, LDX Solutions DUSTEX™ Circulating Dry Scrubber (CDS) at https://www.ldxsolutions.com/circulating-dry-scrubber-cds/, Andritz Group Novel Integrated Desulfurization (NID) at https://www.andritz.com/products-en/pulp-and-paper/environmental-solutions/air-pollution-control/combined-flue-gas-cleaning/novel-integrated-desulfurization.

longer need to operate with the CDS and its integrated baghouse, and thus the removal of the ESP could free up space at the plant site. One of the reasons identified by International Paper for a 1.5 retrofit factor was that production could be lost due to an extended Mill outage. However, many CDS systems have a modular design which enables faster construction and minimizes plant downtime.[44] It must also be noted that the EPA retrofit cost analyzer algorithms that the company used are based on the costs to retrofit controls to an existing facility, and thus space constraints are taken into account in estimating costs. Further, the EPA cost algorithms are for a spray dryer absorber which has a larger footprint than a CDS, and thus would be more difficult to retrofit than a CDS. For all these reasons, along with the fact that the company did not provide any site-specific information to justify the use of any retrofit factor, GEPD should not allow the use of a 1.5 cost retrofit factor for the CDS.

Further, no retrofit factor is justified for DSI which is a much less complex technology than a CDS. DSI consists of the injection of dry sorbent into the flue gas ductwork. It is not considered to be a difficult retrofit, and International Paper has not provided any site-specific information to justify a 1.5 retrofit factor for DSI.

2. International Paper's Costs for an Onsite Landfill Expansion May Be Overestimated.

International Paper included the costs for an onsite landfill expansion for both CDS and DSI "because the mill is currently restricted on the amount of lime product that can be sent to the offsite landfill being used."[45] The costs were based on a 2007 study to expand the plant's onsite landfill done by URS Corporation, which International Paper scaled from 2007 to 2021 dollars. However, EPA's Control Cost Manual advises against escalating costs by more than five years because it can lead to inaccuracies in price estimation.[46] EPA recommends that current cost estimates be obtained rather than escalate costs over such a long timeframe if possible. Further, International Paper did not consider the possibility of increasing the amount of waste that can be sent to the offsite landfill being used or if another landfill could be used for scrubber or DSI waste, rather than expanding its onsite landfill.

In addition, the same acreage of landfill expansion was assumed for both a CDS and DSI.[47] Yet, the sorbent waste rate for DSI as calculated by EPA's cost calculator would 4.90 tons/hour whereas the sorbent waste rate for a dry scrubber is calculated by EPA's cost calculator as 2.6 tons/hour.[48] The waste from a CDS is thus projected to be 47% less than the waste from DSI, and yet International Paper assumed costs for the same size landfill expansion for both DSI and CDS.

Thus, the company appears to have overstated the needed size of the landfill expansion for CDS at PB13, and its estimates of the costs of a landfill expansion may also be overstated due to escalating the costs from 2007 by fifteen years. Moreover, in 2007 when the study was conducted, PB13 was burning coal

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[44] *See*, e.g., Buecker, Brad, Circulating Dry Scrubbers: A New Wave in FGD?, Power Engineering, available at https://www.power-eng.com/emissions/air-pollution-control-equipment-services/circulating-dry-scrubbers-a-new-wave-in-fgd/#gref.
[45] *Id.*
[46] EPA Control Cost Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, November 2017.
[47] International Paper, Regional Haze Rule Four-Factor Analysis for the International Paper Savannah Mill, November 2020, Revised June 2022, Appendix B, at pdf pages 57 and 59.
[48] *Id.*, Appendix B, at pdf pages 56 and 58.

and fuel oil, and now those fuels have been replaced by natural gas. That would presumably result in a lower waste generation rate from PB13 and less landfill space needed than projected in 2007.

3. International Paper Underestimated the SO2 Removal Efficiency of CDS and May Have Overstated the SO2 Removal Efficiency of DSI.

For DSI, International Paper assumed SO2 control of 65%, despite acknowledging that the documentation for the EPA's DSI retrofit costs state that 50% control of SO2 is the target SO2 removal efficiency at a boiler with an electrostatic precipitator (ESP) like PB13 is equipped with.[49] GEPD states in the draft regional haze plan that only 50% SO2 control was assumed for DSI.[50] If this reflects GEPD's view that DSI would not achieve higher than 50% SO2 reduction at the PB13, than GEPD must require the company to revise its DSI cost analysis to reflect 50% control. Otherwise, the company needs to provide support for its assuming 65% SO2 control with DSI at PB13.

For a circulating dry scrubber, International Paper assumed only 90% control of SO2. That is a very low SO2 removal efficiency to assume with a circulating dry scrubber. Sargent & Lundy state that a typical dry FGD retrofit has a target SO2 removal efficiency of 95% of the inlet sulfur, and that a circulating dry scrubber – the technology that was evaluated by International Paper – can meet SO2 removal efficiencies of 98% or greater over a wide range of inlet sulfur concentrations.[51] Thus, International Paper greatly understated the SO2 removal capabilities of CDS.

4. International Paper Took into Account Owner's Costs and Allowance for Funds Used During Construction, which is Not Allowed under the EPA's Control Cost Manual.

International Paper took into account both owners' costs and Allowance for Funds Used During Construction (AFUDC) in its cost effectiveness analyses of DSI and CDS.[52] EPA has stated that such owner's costs for activities related to engineering, management, and procurement are <u>not</u> included in the EPA Control Cost Manual methodology because they are not consistent with the overnight cost method.[53] Thus, GEPD must require that such costs not be included in the company's cost effectiveness analyses.

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[49] *Id.* at 2-11.
[50] June 2022 Draft Georgia Regional Haze Plan at 204.
[51] *See* Sargent & Lundy, IPM Model – Updates to Cost and Performance for APC Technologies, SDA FGD Cost Development Methodology, Final, January 2017, at 1-2, available at https://www.epa.gov/sites/default/files/2018-05/documents/attachment_5-2_sda_fgd_cost_development_methodology.pdf.
[52] International Paper, Regional Haze Rule Four-Factor Analysis for the International Paper Savannah Mill, November 2020, Revised June 2022, Appendix B, at pdf pages 56-57 and at 59.
[53] *See* EPA Control Cost Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, November 2017 at 11 and Section 5, Chapter 1 Wet and Dry Scrubbers for Acid Gas Control, April 2021, at 1-30, available at https://www.epa.gov/sites/default/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf.

5. Revised Cost Analyses to Address Some of these Deficiencies Are Much Lower than Estimated by International Paper and Show that CDS Would Be Very Cost Effective for Power Boiler No. 13

I revised the CDS and DSI cost estimates for PB13 taking several of these deficiencies in International Paper's cost estimates into account. Specifically, I used a retrofit factor of 1, did not include owner's costs or AFUDC, and assumed 95% SO2 control with a CDS. For DSI, I kept the SO2 removal efficiency at the 65% assumed by International Paper. The revised costs are provided in the table below.

Table 5. Revised Cost Effectiveness of CDS and DSI at International Paper Power Boiler 13, 2021 $[54]

Control	SO2 Removal Efficiency	Capital Costs, 2021 $	O&M Costs, $/year	Total Annual Costs, $/year	SO2 removed, tpy	Cost Effectiveness, $/ton (2021 $)
CDS	95%	$134,200,882	$4,150,000	$14,692,000	3,876	$3,790/ton
DSI	65%	$51,746,395	$11,637,000	$15,702,000	2,652	$5,920/ton

It must be noted that the revised costs in the above table are still likely overestimated, particularly because of taking into account the 2007 costs for the landfill expansion that were escalated to 2021 dollars without obtaining a new vendor quote. In addition, these costs are likely overstated because International Paper only assumed a 20-year life for both CDS and DSI. Yet, a 30-year life is justified for dry scrubbers and DSI.[55] If a 30-year life of CDS was assumed, the cost effectiveness would be reduced to $3,259/ton.

The revised costs shown in Table 5 above demonstrate that CDS would be very cost effective at $3,790/ton and would result in significant reductions of approximately 3,900 tons per year of SO2 from PB13.

Not only is CDS the most cost effective SO2 control evaluated for the Power Boiler No. 13, but it also has many other benefits as an SO2 control. Of all of the FGD systems, circulating dry scrubbers have the lowest energy usage, as well as low freshwater usage and zero liquid discharge.[56] The Southwestern Electric Power Company (SWEPCO) has recently installed a NID™ system at the Flint Creek Power Plant in Arkansas. Flint Creek is a 528 MW unit that burned low sulfur Powder River Basin coal with a 0.8 lb/MMBtu uncontrolled SO2 rate.[57] After evaluating several SO2 control systems, SWEPCO selected a NID™ system for SO2 control for the following benefits of a NID system: lowest capital and operation and maintenance costs on a 30-year cumulative present worth basis, lowest water consumption, lowest auxiliary power usage, lowest reagent usage, smallest footprint, best for mercury reduction with

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[54] *See* Ex. 3. EPA's Retrofit Cost Analyzer Spreadsheet for International Paper Power Boiler No. 13 for revised CDS and DSI cost effectiveness calculations.

[55] *See*, e.g., EPA, Control Cost Manual, Section 5, Chapter 1 Wet and Dry Scrubbers for Acid Gas Control, April 2021, at 1-8.

[56] *See* https://www.babcock.com/products/circulating-dry-scrubber-cds.

[57] *See* February 8, 2012 Direct Testimony of Christian T. Beam on behalf of Southwestern Electric Power Company, In the Matter of Southwestern Electric Power Company's Petition for a Declaratory Order Finding that Installation of Environmental Controls at the Flint Creek Power Plant is in the Public Interest, Before the Arkansas Public Utilities Commission, Docket 12-008-U, at 5, 18 (Ex. 4).

activated carbon injection, best for SO3 removal, and best for future National Pollution Discharge Elimination System (NPDES) permit compliance.[58] In addition, as previously stated, its compact size and modular design enables faster construction and minimizes downtime during construction.[59] For these reasons, neither the energy or non-air environmental impacts nor the time to construct the controls would present a valid reason to exclude CDS from consideration as a reasonable progress measure. The life of a CDS is at least 20 years, and International Paper has also stated that the life of Power Boiler 13 is at least 20 years. Thus, the remaining useful life of the Power Boiler is also not a reason to dismiss the very cost effective control of CDS.

Thus, GEPD should adopt a requirement for International Paper to install a CDS to achieve 95% SO2 reductions, almost 3,900 tons of SO2 reduced per year, at Power Boiler 13. At $3,790/ton, this control should be considered cost effective and also highly effective at reducing SO2 emissions.

IV. Georgia Power Co. - Plant Scherer

Georgia Power's Plant Scherer is a four unit coal-fired power plant located in Monroe County near Macon, Georgia. Unit 4 of Plant Scherer ceased operations on December 31, 2021.[60] Plant Scherer Units 1-3 are each equipped with an ESP, SCR, a wet lime FGD scrubber, and a baghouse with powdered activated carbon. The table below shows the 2017-2021 five-year average SO2 and NOx emissions from each Scherer unit.

Table 6. Plant Scherer Units 1-3 SO2 and NOx Emissions Averaged Over 2017-2021[61]

Plant Scherer Unit	SO2, tons per year	NOx, tons per year
1	183	2,206
2	240	1,685
3	270	2,014
Total	693	5,905

Despite Units 1-3 being equipped with these top level air pollutant controls, the units are not consistently achieving emission rates that reflect the pollutant removal capabilities of these controls. The table below shows the maximum and average 30-boiler operating day average SO2 and NOx rates for each Scherer Unit 1-3 over 2017-2021 to illustrate this point.

[58] *Id.* at 19-21.
[59] *See*, e.g., Buecker, Brad, Circulating Dry Scrubbers: A New Wave in FGD?, Power Engineering, available at https://www.power-eng.com/emissions/air-pollution-control-equipment-services/circulating-dry-scrubbers-a-new-wave-in-fgd/#gref.
[60] *See*, e.g., https://www.flpublicpower.com/news/jea-reducing-carbon-emissions-with-closure-of-plant-scherer-coal-fired-unit.
[61] Based on emissions data reported to EPA's Air Markets Program Database.

Table 7. Maximum and Average 30-Boiler Operating Day Average SO2 and NOx Emission Rates Over 2017-2021, Plant Scherer Units 1-3[62]

Plant Scherer Unit	Max SO2, 30-BOD Avg, lb/MMBtu	Average SO2 30-BOD Avg, lb/MMBtu	Max NOx, 30-BOD Avg, lb/MMBtu	Average NOx 30-BOD Avg, lb/MMBtu
1	0.16	0.02	0.42	0.16
2	0.20	0.02	0.25	0.13
3	0.03	0.02	0.32	0.14

As shown in the above table, the SO2 emission rate at each Scherer unit is often very low, averaging 0.02 lb/MMBtu, but at times, SO2 emission rates are as much as ten times higher. A review of the Title V permit conditions for the Scherer units shows that the units are not subject to federally enforceable permit conditions that require continuous compliance with SO2 emission limits that reflect the capabilities of the units' SO2 controls. While the Plant Scherer Title V permit does require that each unit achieve 95% removal of the inlet SO2 concentration to the wet FGDs on a 30-boiler operating day average basis, there are several exemptions from that 95% SO2 removal requirement including for startups, shutdown, scheduled maintenance, malfunction, relative accuracy test audits (RATA), some performance testing, and GEPD-approved periods of research and development of emission control technologies.[63] These requirements have been designated in the Title V permit as "state-only" enforceable.[64] GEPD should evaluate removing these exemptions to ensure more continuous compliance with the 95% reduction requirement. Alternatively, GEPD should consider imposing a long term average SO2 limit that will ensure the Scherer units' scrubbers are operating and maintained to ensure maximum SO2 removal efficiency. On a long term basis, each Plant Scherer unit is achieving an annual SO2 emission rate in the range of 0.01 to 0.02 lb/MMBtu. Thus, imposing an annual SO2 emissions limit of 0.02 lb/MMBtu, in addition to the 95% control requirements of the permit, would lock in the very low SO2 emission rates and ensure that SO2 emissions from the Scherer units do not increase in the future.

In contrast to the actual SO2 emission rates, the NOx emission rates at each Scherer unit vary greatly and do not reflect the capabilities of the SCR controls installed at the units. A review of the Plant Scherer Title V permit shows that the permit has NOx emission limits that only apply during the May to September ozone season and those emission limits offer a lot of flexibility in the required NOx emission rates. Specifically, the permit imposes a 7-power plant NOx emission limit of 32,355.8 tons per ozone season (May 1 through September 30), which includes the NOx emissions from Plant Scherer Units 1-4, Plant Bowen Units 1-4, Plant Wansley Units 1-2, and Plant Yates Units 6-7.[65] Ozone season NOx emissions from these over 2020-2021 (i.e., Bowen, Scherer, Wansley, and Yates Units 6 and 7 (which are now gas-fired units)) ranged from 3,4225 to 4,667 tons per ozone season. Thus, this 7-power plant NOx

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[62] Calculated from data reported to EPA's Air Markets Program Database for 2017-2021, see data in Ex. 5.
[63] GEPD, Scherer Steam-Electric Generating Plant, Air Quality – Part 70 Operating Permit No. 4911-207-008-V-04-0, 12/14/2018, Conditions 3.4.15, 3.4.17, 3.4.18, and 3.4.19.
[64] *Id.*
[65] *Id.,* Condition 3.2.4. As discussed in Section II above, the 7-power plant cap now only includes 4 plants because Plants Branch, Hammond, and McDonough are no longer operating.

emission limit will not ensure that NOx emissions from the Plant Sherer units are maintained, nor will the limit ensure that the SCR systems are operated and maintained for optimal NOx removal.

The Plant Scherer Title V permit also has individual unit NOx limits that only apply during the ozone season as follows: Unit 1 - 0.20 lb/MMBtu 30 day average, Unit 2 - 0.17 lb/MMBtu, 30 day average, and Unit 3 - 0.15 lb/MMBtu, 30 day average.[66] If any unit does not comply with these limits, then the Plant Scherer units must comply with a 30-day average NOx limit of 0.17 lb/MMBtu averaged over all Scherer units during the ozone season, and they must comply with a 30-day average 7-plant NOx emission limit of 0.18 lb/MMBtu.[67] However, these emission limits also do not reflect the NOx capabilities of the Scherer units' NOx controls either.

A review of ozone season NOx emission rates at Plant Scherer Units 1-3 shows that the average of each unit's 30-boiler operating day average NOx emission rate over the ozone seasons of the past five years (2017-2021) is 0.08 lb/MMBtu.[68] Indeed, each unit had 30-boiler operating day average NOx emission rates at or below 0.08 lb/MMBtu for approximately 81% of the time during the ozone season. Thus, the NOx emission limits in the current Title V permit do not reflect the optimal operation of the NOx controls at each unit including the SCR.

GEPD thus must evaluate setting lower NOx emission limits for each Plant Scherer unit to ensure that the SCRs are operated continuously throughout the year and to ensure optimal operation of the SCR systems. The actual emissions data for each Plant Scherer unit during the ozone season support a 30-boiler operating day average limit of 0.08 lb/MMBtu for each unit. Based on the emission rates actually being achieved at each Plant Scherer unit during the ozone season, each unit is clearly capable of achieving a 0.08 lb/MMBtu NOx emission rate on a 30-boiler operating day average basis. Based on the 2017-2021 annual average heat input at each unit, requiring compliance with a 0.08 lb/MMBtu 30-boiler operating day average NOx limit at each unit would result in approximately 2,420 tons per year of NOx emissions reduced from 2017-2021 NOx emissions at Plant Scherer Units 1-3. This significant emission reduction could be achieved at no capital cost but with the operational expense of increased operation of the SCR system and thus would surely be cost effective.

V. Georgia Power Company – Plant Wansley

Georgia Power's Plant Wansley has two coal-fired EGUs capable of producing 1,840 MW of electricity in total. The plant is located in Franklin, Georgia. The two units are each equipped with ESPs, low NOx burners, closed-coupled/separated overfire air, SCR, and wet lime FGD scrubbers. GEPD did not conduct a four-factor analysis of controls or emission reduction requirements for this power plant. The table below shows the 2017-2021 five-year average SO2 and NOx emissions from each Scherer unit.

[66] *Id.*, Conditions 3.4.6, 3.4.7, and 3.4.8.
[67] *Id.*, Conditions 3.4.10 and 3.4.11.
[68] *See* Ex. 5, Spreadsheet with Plant Scherer Daily 2017-2021 SO2 and NOx Emissions Evaluation.

Table 8. Plant Wansley Units 1 and 2 SO2 and NOx Emissions Averaged Over 2017-2021[69]

Plant Wansley Unit	SO2, tons per year	NOx, tons per year
1	864	535
2	655	505
Total	1519	1040

Despite Units 1-3 being equipped with these top level air pollutant controls, the units are not consistently achieving emission rates that reflect the pollutant removal capabilities of these controls. The table below shows the maximum and average 30-boiler operating day average SO2 and NOx rates for each Scherer Unit 1-3 over 2017-2021 to illustrate this point.

Table 9. Maximum and Average 30-Boiler Operating Day Average SO2 and NOx Emission Rates Over 2017-2021, Plant Wansley Units 1 and 2[70]

Plant Wansley Unit	Max SO2, 30-BOD Avg, lb/MMBtu	Average SO2 30-BOD Avg, lb/MMBtu	Max NOx, 30-BOD Avg, lb/MMBtu	Average NOx 30-BOD Avg, lb/MMBtu
1	0.17	0.13	0.18	0.09
2	0.17	0.13	0.17	0.11

While the Plant Wansley Title V permit does require that each unit achieve 95% removal of the inlet SO2 concentration to the wet FGDs on a 30-boiler operating day average basis, there are several exemptions from that 95% SO2 removal requirement including for startups, shutdown, scheduled maintenance, malfunction, relative accuracy test audits (RATA), some performance testing, and EPD-approved periods of research and development of emission control technologies.[71] These requirements have been designated in the Title V permit as "state-only" enforceable.[72] GEPD should evaluate removing these exemptions to ensure more continuous compliance with the 95% reduction requirement. Alternatively, GEPD should consider imposing a long term average SO2 limit that will ensure the Wansley units' scrubbers are operating and maintained to ensure maximum SO2 removal efficiency. Based on a review of annual SO2 emission rates over the past five years, both Plant Wansley Units 1 and 2 should be able to meet an annual average SO2 limit in the range of 0.13-0.14 lb/MMBtu, with no exemptions necessary.

With respect to NOx, the Plant Wansley Title V Permit includes the same 7-power plant NOx emission limit of 32,355.8 tons per ozone season that applies to Plant Bowen and Plant Scherer and is discussed in Sections II and IV above.[73] As with Plants Bowen and Scherer, this 7-power plant limit does not effectively control NOx from the Wansley units because the compliance buffer between actual and allowable emissions is so large. The Wansley units also appear to be subject to NOx emission limits of 0.07 lb/MMBtu, applicable during the ozone season on a 30-day average basis.[74] However, the permit

[69] Based on emissions data reported to EPA's Air Markets Program Database.
[70] Calculated from data reported to EPA's Air Markets Program Database for 2017-2021, see data in Ex. 6.
[71] GEPD, Wansley Steam-Electric Generating Plant, Air Quality – Part 70 Operating Permit Amendment No. 4911-149-0001-V-03-3, 1/21/2015, Conditions 3.4.13 and 3.4.14.
[72] *Id.*
[73] *Id.*, Condition 3.26.
[74] *Id.*, Conditions 3.4.7 and 3.4.8.

allows for an exception to complying with the 0.07 lb/MMBtu NOx limit, if the NOx emissions from Plant Bowen Units 1-4, Plant Wansley Units 1 and 2, and Plant Yates Units 6 and 7 do not exceed 0.13 lb/MMBtu on a 30-day average and if the NOx emissions from all of these units and from Plant Scherer Units 1-4 do not exceed 0.18 lb/MMBtu on a 30-day average.[75] These limits also only apply during the ozone season.

Given that GEPD has imposed ozone seasons NOx limits of 0.07 lb/MMBtu applicable on a rolling 30-day average basis in the Title V permit for Plant Wansley, then presumably GEPD has found that Wansley Units 1 and 2 can meet a NOx limit of 0.07 lb/MMBtu on a rolling 30-day average basis. Currently, Unit 1's 30-boiler operating day average NOx emission rate during the ozone season averages 0.09 lb/MMBtu and Unit 2's NOx rate averages 0.10 lb/MMBtu during the ozone season over the past five years, but the units each have maintained 30-day average NOx emissions of 0.07 lb/MMBtu approximately have of the time during the ozone season. Thus, the units and SCR systems are capable of meeting a 0.07 lb/MMBtu NOx limit. Accordingly, GEPD should evaluate the control option of requiring each Wansley unit to meet a 0.07 lb/MMBtu NOx emission limit year-round. At the minimum, GEPD should evaluate imposing a long term average limit that reflects year-round operation of the SCR systems at each Plant Wansley unit. Based on a review of the ozone season NOx emission rates achieved at each unit, an appropriate long term average limit for the units should be in the range of 0.07-0.08 lb/MMBtu.

[75] *Id.*, Conditions 3.4.9 and 3.4.10.

Exhibit	Description
1	Spreadsheet with Plant Bowen Daily 2017-2021 SO2 and NOx Emissions Evaluation
2	Spreadsheet with Coal Data from Energy Information Administration's Coal Data Browser, Shipments to Bowen
3	EPA's Retrofit Cost Analyzer Spreadsheet for International Paper Power Boiler No. 13 for revised CDS and DSI cost effectiveness calculations.
4	February 8, 2012 Direct Testimony of Christian T. Beam on behalf of Southwestern Electric Power Company, In the Matter of Southwestern Electric Power Company's Petition for a Declaratory Order Finding that Installation of Environmental Controls at the Flint Creek Power Plant is in the Public Interest, Before the Arkansas Public Utilities Commission, Docket 12-008-U
5	Spreadsheet with Plant Scherer Daily 2017-2021 SO2 and NOx Emissions Evaluation
6	Spreadsheet with Plant Wansley Daily 2017-2021 SO2 and NOx Emissions Evaluation