Southern Company

Jeffrey A. Burleson
Senior Vice President
Environment, System Planning & Sustainability

Southern Company Services, Inc.
600 18th Street North
Birmingham, AL 35203
205 257 3090 tel
205 757 2027 fax
jaburles@southernco.com

August 8, 2023

EPA Docket Center, U.S. EPA
Attn: Docket ID No. EPA–HQ–OAR–2023–0072
Mail Code 28221T
1200 Pennsylvania Avenue NW
Washington, DC 20460

VIA ELECTRONIC SUBMISSION AT: www.regulations.gov

RE: New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule; Proposed Rule; 88 Fed. Reg. 33,240 (May 23, 2023)

Dear Principal Deputy Assistant Administrator Goffman,

The Southern Company appreciates the opportunity to submit these comments in response to the U.S. Environmental Protection Agency's (EPA) May 23, 2023, Federal Register notice seeking public input on EPA's proposed standards of performance for new, modified, and reconstructed fossil fuel-fired electric generating units (EGUs) and emission guidelines for existing EGUs. We support regulatory action that achieves greenhouse gas (GHG) emissions reductions from the electric sector while recognizing the importance of maintaining clean, safe, reliable, and affordable energy for the customers and communities we are privileged to serve. These comments are submitted on behalf of The Southern Company and its subsidiaries: Alabama Power Company, Georgia Power Company, Mississippi Power Company, and Southern Power Company.

The Southern Company is committed to GHG emissions reductions and has a goal of net-zero GHG emissions by 2050. We have made excellent progress toward our goal and in 2022 have already achieved a 46 percent reduction in GHG emissions from 2007 levels. Since 2007, Southern Company has retired or converted to natural gas over 10,000 MW of nameplate coal generating capacity, representing about 75 percent of our coal generating units. As one of the largest utilities in the nation, and through our long commitment to research and development to advance low- and no-carbon technologies, we understand the importance of decarbonizing at a pace that is supported by technology and infrastructure advancement to enable an orderly energy transition.

As we continue our transition to net-zero GHG emissions, we remain focused on maintaining a reliable and resilient system that provides service at just and reasonable rates for our customers. To facilitate

the ongoing energy transition, we encourage EPA to consider refinements and clarifications to the proposal. Some of the key points discussed in our comments include:

- Support for subcategories and compliance flexibilities under Clean Air Act section 111 regulations and recommended refinements to mitigate reliability and affordability concerns;
- Recognition that states are delegated broad flexibility under section 111 to address reliability and affordability concerns under the "remaining useful life and other factors" (RULOF) provision; and
- Extending the proposed compliance timelines to better reflect expected project schedules and adjusting the proposed subcategory thresholds to facilitate the ongoing energy transition.

The Southern Company commits to collaboration on this rulemaking, and we look forward to continuing our engagement with the Agency on this topic. We confirm that Southern Company will engage constructively with EPA to support carbon standards for not only existing coal but also for new and existing gas plants in their final form. If you have any questions about these comments or need additional information, please do not hesitate to contact me or Justin Walters at (205) 257-7558 or jwalters@southernco.com.

Sincerely,



Jeffrey A. Burleson
Senior Vice President
Environment, System Planning & Sustainability

CC Mr. Christian Fellner
Ms. Lisa Thompson



Comments of

The Southern Company

to the

U.S. Environmental Protection Agency

NEW SOURCE PERFORMANCE STANDARDS FOR GREENHOUSE GAS EMISSIONS FROM NEW, MODIFIED, AND RECONSTRUCTED FOSSIL FUEL-FIRED ELECTRIC GENERATING UNITS; EMISSION GUIDELINES FOR GREENHOUSE GAS EMISSIONS FROM EXISTING FOSSIL FUEL-FIRED ELECTRIC GENERATING UNITS; AND REPEAL OF THE AFFORDABLE CLEAN ENERGY RULE

88 Fed. Reg. 33,240 (May 23, 2023)

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I. INTRODUCTION.

On May 23, 2023, the U.S. Environmental Protection Agency (EPA or Agency) published a proposed rulemaking package, titled *New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule*[1] (proposal or proposed rules), to regulate greenhouse gas (GHG) emissions from fossil fuel-fired electric generating units (EGUs) under section 111 of the Clean Air Act (CAA). This package includes proposed revisions to new source performance standards (NSPS) for carbon dioxide (CO_2) emissions from new, modified, and reconstructed fossil fuel-fired EGUs under section 111(b) of the CAA and proposed emissions guidelines for states to develop plans to regulate CO_2 emissions from existing EGUs under section 111(d) of the CAA. EPA is also proposing to repeal the Affordable Clean Energy Rule.

The Southern Company (Southern Company or the Company) is a leading energy company serving nine million customers through its subsidiaries.[2] Southern Company is committed to GHG emissions reductions and has a goal of net-zero GHG emissions by 2050 that recognizes the importance of decarbonizing at a pace that is supported by technology and infrastructure advancement. Southern Company is committed to a net-zero future and appreciates EPA's recognition in the proposal that flexibility is needed for the continued transition of the generating fleet. It is important for EPA to recognize and support the broad authority provided to states under section 111 of the CAA to address reliability and affordability concerns. The timelines in the proposal, some of which are infeasible, could lead to an inefficient fleet transition pathway that adds unnecessary costs and reliability risk for customers. As discussed in these comments, we recommend refinements and clarifications to EPA's proposal to support the ongoing energy transition to ensure clean, safe, reliable, and affordable energy for the customers and communities we are privileged to serve.

[1] 88 Fed. Reg. 33,240 (May 23, 2023).

[2] Southern Company is a holding company that conducts its business through its subsidiaries; accordingly, unless the context otherwise requires, references in these comments to Southern Company's operations, such as generating activities and GHG emissions, refer to those operations conducted through its subsidiaries.

While population and the economic growth in the Southeast region of the United States are expected to outpace the nation through the 2030s, our customers are challenged by the effects of inflation and rising costs across the economy. Maintaining affordable and reliable electric service for our communities is critical to supporting this growth as the power sector and the rest of the economy transition to net-zero GHG emissions. During this critical period, the proposed rules would place widespread additional constraints on the electric grid, which agencies, such as the North American Electric Reliability Corporation (NERC), have cautioned will already face challenges across the nation, even absent the additional pressures from this proposal. EPA's regulatory impact analysis for the proposed rules likely substantially underestimates the risks, costs, and time requirements of the proposal. Transmission, pipelines, and other critical elements and infrastructure affecting cost and schedule are not adequately accounted for and projections of availability and cost of the proposed "best system of emissions reduction" (BSER) options for reducing GHGs from fossil-fired EGUs, such as carbon capture and sequestration (CCS) and low-GHG hydrogen (H_2), are unrealistic. While the full impacts of constraining numerous critical electric generation resources on an already challenged system cannot be quantified within the short time frame allowed for public comment, we believe that these incremental and unquantified costs of the proposal are likely significant.

While the proposal suggests that power plant operators have a choice in how to comply with the proposed rules and, thus, can optimize cost by choosing the least-cost option, that assumption overlooks important factors that may constrain or eliminate choice in many cases. For example, the proposal suggests capacity factor limitations and early retirement of units as alternatives to installation of emissions reduction technology. However, if the technology options or timelines are infeasible or cost-prohibitive for a facility, the options become limited and the resulting impacts to the system and the associated costs cannot be mitigated. When regulatory compliance obligations force capacity factor limitations or early retirement for critical generating units, especially during an era of increasing electricity load, additional resources will be needed to maintain the same level of system reliability, increasing the costs of the proposal by requiring a much larger amount of installed capacity.

EPA should ensure that all costs and reliability impacts of the proposed section 111 rules are better understood and more fully evaluated before moving forward with rule finalization. While such complex analyses cannot be completed in the time allowed by the public comment period,

Southern Company urges EPA to take the time that is necessary, including consulting with regional reliability authorities, state public service commissions, and vertically integrated regulated utilities to more fully understand the impacts, both at the plant level and to the electric grid, rather than rush to finalize rules that may result in unintended consequences that adversely impact customers. At a minimum, significantly extending the proposed timelines for compliance would provide a better opportunity for technology and infrastructure advancement to reduce cost and reliability impacts over time. Compliance flexibilities that can reduce compliance costs and help maintain affordability while protecting reliability are necessary to mitigate risks to customers.

Southern Company appreciates the opportunity to comment on this important rulemaking and respectfully submits these comments on behalf of itself and four of its subsidiaries.[3] Southern Company is uniquely qualified to provide input to EPA as its subsidiaries own and operate fossil fuel-fired EGUs and as a company that has long been committed to research and development to improve electric generation, including our recent efforts to advance carbon capture, utilization, and sequestration through our management and operation of the Department of Energy's (DOE's) National Carbon Capture Center (NCCC).

A. Southern Company supports constructive regulatory action that does not disrupt the orderly transition toward net-zero emissions.

Climate change is real, and Southern Company supports U.S. engagement in a coordinated, global strategy to address climate change by actively advancing a net-zero by 2050 goal in alignment with the commitments of the landmark Paris Agreement. According to EPA data, as of 2021, the power sector has reduced its GHG emissions by nearly 36 percent relative to 2005, more than any other sector of the economy.[4] According to the Edison Electric Institute (EEI), "50 EEI member companies have announced ambitious emissions reduction commitments, 41 of which aim for net-zero or equivalent by 2050 or sooner."[5]

[3] Alabama Power Company, Georgia Power Company, Mississippi Power Company, and Southern Power Company.

[4] https://cfpub.epa.gov/ghgdata/inventoryexplorer/index.html

[5] https://www.eei.org/-/media/Project/EEI/Documents/Issues-and-Policy/Finance-And-Tax/WSB-Prepared-Remarks.pdf.

Southern Company has previously announced its own goal of net-zero GHG emissions by 2050 with an interim goal to achieve a 50 percent GHG emissions reduction by 2030 relative to 2007 levels. Southern Company has made excellent progress toward these goals while driving business decisions that are in the best interest of our customers. We are on track to meet our interim goal as early as 2025, having already achieved a 46 percent reduction in GHG emissions from 2007 levels in 2022. Since 2007, Southern Company has retired or converted to natural gas over 10,000 megawatts (MW) of nameplate coal generating capacity, representing about 75 percent of our coal generating units and more than 50 percent of our coal nameplate capacity. Subject to regulatory approval, we expect to have eight to ten coal units remaining in operation by the end of 2028, down from 66 in 2007, with further reductions expected by 2035. Our current portfolio of more than 15,000 MW of clean energy resources will continue to grow, with a total of over 21,000 MW expected by 2030.

As we continue our transition to net-zero GHG emissions, we remain focused on maintaining a reliable and resilient system that provides service at just and reasonable rates for our customers. As an industry leader in research and development for more than 50 years, Southern Company is well-positioned to facilitate an orderly transition to a net-zero GHG emissions electric generation fleet.

Southern Company is one of the largest owners of renewable resources in the U.S. In 2022, nearly one-third of the electricity generated or purchased by Southern Company subsidiaries came from clean energy resources, including solar, wind, biomass, landfill gas, hydro, and nuclear. Georgia Power is also completing construction of the first new nuclear units in the U.S. in over 30 years at Plant Vogtle (Units 3 & 4), with Unit 3 successfully placed into commercial operation on July 31, 2023. The final stages of construction and testing continue at Unit 4, with the unit projected to be placed in service during the late fourth quarter 2023 or the first quarter of 2024. Once all four units are online, the Plant Vogtle site will be the largest generator of clean energy in the nation.[6]

The electric utility industry is in a critical period of transition as it continues toward decarbonization, with the ongoing retirement of coal-fired EGUs and increased deployment of renewable energy resources occurring at a staggering pace. According to NERC, "Energy systems

[6] https://www.southerncompany.com/newsroom/clean-energy/vogtle-unit-3-goes-into-operation.html.

and the electricity grid are undergoing unprecedented change on a scope, scale, and speed that challenges the ability to foresee and design for their future states."[7] Thus, the recent high rate of coal-fired EGU retirements across the U.S. has introduced new risk to grid reliability that must be mitigated. Dispatchable and reliable resources are necessary, and coal-fired units, with their ability to store months of fuel on-site, have long been relied upon to ensure these critical elements. NERC expressed concern in its 2021 Long Term Reliability Assessment (LTRA) that the retirement of fossil fuel-fired generation "accelerates the change in resource mix and punctuates the urgency for implementing resource adequacy and energy sufficiency initiatives…."[8] In its 2022/2023 Winter Reliability Assessment, NERC found that "[a] large portion of the North American [bulk power system] is at risk of insufficient electricity supplies during peak winter conditions."[9] These concerns about reliability will only be exacerbated in the next several years as additional coal-fired EGUs retire and electric load continues to grow.

As a general matter, the section 111 regulations for the power sector should support and facilitate the ongoing and orderly transition of the power sector. NERC recommends that, "[r]egulatory and policy-setting organizations should use their full suite of tools to manage the pace of retirements and ensure replacement infrastructure can be timely developed and placed in service."[10] To that end, EPA should make clear that states have broad authority to include compliance flexibilities in state plans that are needed for utilities to respond to the evolving needs of the electric grid. Furthermore, EPA should take steps to harmonize any section 111 compliance and implementation deadlines with announced power sector plans and other impactful environmental rules and existing regulatory programs that could drive EGU retirements or changes to facility operations. Current rulemaking efforts include, but are not limited to, EPA's 2023 Supplemental Effluent Limitation Guidelines (ELG) proposal,[11] which similarly utilizes

[7] 2022 Long Term Reliability Assessment Press Release, North American Electric Reliability Corporation (December 15, 2022) https://www.nerc.com/news/Headlines%20DL/2022_LTRA_Release.pdf.

[8] 2021 Long Term Reliability Assessment, North American Electric Reliability Corporation (Dec. 17, 2021) https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2022.pdf..

[9] 2022/23 Winter Reliability Assessment, North American Electric Reliability Corporation (Nov. 17, 2022)https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2022.pdf.

[10] 2022 Long Term Reliability Assessment, North American Electric Reliability Council (Dec. 15, 2022)https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2022.pdf.

[11] 88 Fed. Reg. 18,824 (Mar. 29, 2023).

compliance subcategories, and EPA's Good Neighbor Plan rule.[12] In addition to these recent rulemaking efforts, it is also important for EPA to consider that compliance with the 2020 ELG Rule is expected to result in nearly 10,000 MW of retirements of dispatchable coal-fired generation in the year 2028 alone.[13] Accordingly, the power sector needs appropriate time to evaluate the impact of multiple rulemakings on the generation fleet and to make informed decisions that are protective of the environment and in the best interests of customers.

B. EPA should finalize Section 111 GHG rules for the power sector that better provide the flexibility needed to ensure clean, safe, reliable, and affordable service for customers and avoid unnecessary disruption to the ongoing orderly fleet transition.

One foundational aspect of the electric utility industry is that our product must be delivered to customers in the exact quantity needed on a real-time, second-by-second basis. To provide this service in a reliable manner, the generating fleet is connected to our customers through hundreds of thousands of miles of transmission and distribution lines and thousands of substations across multiple states. This system, while complex to operate and maintain, provides us with the flexibility to serve customers in a way that optimizes costs while achieving high degrees of reliability. The transition of the generating fleet to low- and no-carbon resources requires careful consideration and coordination of intricate, interrelated system impacts and thorough planning for each retirement, conversion, expansion, or addition of generation, transmission/distribution, fuel delivery, and other associated infrastructure.

The electric utility industry and the Southeast region we serve are at a critical juncture in the clean energy transition to ensure reliable and affordable electric service for our customers for the coming decades. The transition of the power sector is a complex and long-term endeavor that must account for the time and costs to deploy necessary transmission and replacement generation resources, as well as the associated technology development, infrastructure needs, and the supporting policy, legal, and permitting frameworks that must be put into place. While Southern Company supports constructive regulation that is aligned with our net-zero goal, the proposed rules would impose severe limitations on resources that are needed to support our ongoing fleet

[12] 88 Fed. Reg. 36,654 (June 5, 2023).

[13] U.S. Energy Information Administration - EIA - Independent Statistics and Analysis (https://www.eia.gov/todayinenergy/detail.php?id=54559).

transition and the reliability of service to customers. We believe EPA has heavily underestimated the potential impacts and time frames necessary for complying with the proposed standards, which would unnecessarily impede our ability to provide clean, safe, reliable, and affordable energy to customers in support of our net-zero goal.

Southern Company anticipates the eventual retirement of our coal fleet and the continued advancement of clean energy technologies in conjunction with our transition to net-zero emissions. However, this transition must occur in a responsible manner over time to address the robust growth in customer demand that the Southeast region is experiencing, as well as the necessary, but extensive and expensive, infrastructure investments that are required. New and growing industries are driving rapid economic expansion in the Southeast, especially in the state of Georgia. Since Georgia Power filed its 2022 Integrated Resource Plan (IRP), load forecasts have increased dramatically, highlighting the need to maintain flexibility in resource planning to continue to ensure clean, safe, reliable, and affordable electricity. Through 2031, Georgia Power's winter peak demand is projected to grow by more than 25 percent relative to its forecast winter peak demand for 2024 – a substantial amount of growth that is forecast to materialize in less than a decade.

The robust pipeline of both committed and potential projects in Georgia corresponds to an influx of new business lines, including hyper-scale data centers and the electric vehicle industry. Not only does the scale of individual projects fall outside of historical norms, with some projects surpassing 1,000 MW each, the energy profiles of these new load additions are also more intensive. High load factor facilities, such as solar panel, electric vehicle, battery, or other clean energy support manufacturing, and especially data centers, require a substantial amount of generation and consistent and/or high levels of reliable energy delivery around the clock. Supporting these energy needs with reliable electric service is key to the continued advancement of technology to support the achievement of net-zero across the economy. Prematurely constraining dispatchable resources, such as the remaining coal units and efficient natural gas combined cycles (NGCC), could hurt the long-term transition of the economy by risking the continued availability of reliable and affordable electricity to serve clean technology industries that renewables alone are not yet ready to serve.

Given regulatory, permitting, and construction timelines for new resources and the need to respond to any changes in the load forecast, a comprehensive and flexible solution is critical to ensure the timely development of generation, transmission, and demand-side resources necessary to serve and sustain the accelerated expansion of the economies of the Southeast region.

Therefore, Southern Company encourages EPA to recognize that decisions regarding the continued operation or retirement of existing generation resources, the addition of new generation sources, expansion of transmission capacity and pipelines, and expansion plans for load growth are closely interrelated and must be carefully coordinated. Further, as renewable and distributed energy resources continue to grow in our service territories, the importance of maintaining adequate dispatchable resource options increases accordingly, as these resources are needed to maintain grid reliability while serving increasing load demand. Our electric operating companies must consider all these elements together in their comprehensive, coordinated generation and transmission integrated resource planning processes within their respective state regulatory constructs. While EPA's section 111 proposal provides some acknowledgements of the importance of unit-specific and state-specific needs, the proposal does not adequately account for these critical interrelated and interconnected considerations and, in some cases, such as infrastructure requirements and constraints, does not account for them at all. Thus, in support of achieving constructive regulation that meets the needs of customers and the environment, these comments cover the important considerations that we urge EPA to fully evaluate before finalizing the section 111 GHG rules for the power sector.

II. SOUTHERN COMPANY SUPPORTS SUBCATEGORIES AND COMPLIANCE FLEXIBILITIES UNDER SECTION 111 REGULATION AND RECOMMENDS REFINEMENTS AND CLARIFICATIONS.

A. Southern Company supports subcategorization under section 111 as an equitable approach for addressing CO_2 emissions reduction options across the diverse fleet of fossil generating units.

Resilience, reliability, and affordability are critical considerations as the power sector transitions. Subcategorization of units based on unit retirement plans and/or unit utilization recognizes the need for dispatchable capacity resources necessary to support the power sector's ongoing fleet transition and our ability to maintain a resilient, reliable, and affordable electric system. Southern Company appreciates EPA's acknowledgement of these concerns and the need for subcategorization. Subcategories for existing fossil generating units based on planned retirement dates and utilization can provide important compliance flexibility; however, as discussed throughout these comments, longer compliance and implementation time frames than those EPA has proposed are necessary to support a reliable and affordable energy transition and to

align with other power sector rules, including, but not limited to, EPA's Supplemental ELG proposal.

With regard to new sources, EPA may establish subcategories directly in accordance with CAA section 111(b)(2), which states, "The Administrator may distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing such standards."[14] In comparison, for existing sources, CAA section 111(d)(1) states,

> Regulations of the Administrator under this paragraph shall permit the State in applying a standard of performance to any particular source under a plan submitted under this paragraph to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies.[15]

EPA is thus directed to afford states substantial flexibility in setting unit-specific standards in accordance with EPA emission guidelines, including flexibility to establish subcategories with differing retirement dates and/or operational constraints based on state-specific concerns such as electric reliability, customer costs, economic development, and other state concerns.

B. EPA should acknowledge the broad flexibility that section 111(d) delegates to states to address reliability and affordability concerns under the "remaining useful life and other factors" (RULOF) provision.

Section 111(d) is a hallmark of the cooperative federalism model that Congress has embedded throughout the CAA. Under that provision, the Administrator prescribes regulations that establish a procedure for states to submit a plan to EPA establishing standards of performance for existing sources within the category to which a standard of performance would apply if such source were a new source. Thus, although it is the responsibility of the Administrator to lay out the process for states to follow, it is ultimately the substantive responsibility of the states to establish standards of performance for the designated existing sources within their jurisdictions. The CAA does not stop here, though. It goes on to say that the Administrator "*shall* permit the state in applying a standard of performance […] to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies."[16] This provision

[14] 42 U.S.C. § 7411(b)(2).

[15] *Id.* at § 7411(d)(1).

[16] *Id*. (emphasis added).

of the CAA delegates broad authority to states to address unique situations and circumstances in applying standards of performance to sources under their purviews.

Congress's decision to rest the substantive decision-making under section 111(d) with each state makes eminent sense given significant changes in the electric grid are occurring at an unprecedented pace, including retirements of substantial amounts of dispatchable generation, rapidly growing amounts of variable renewable generation, and the extensive transmission buildout that is necessary to support these changes. Relative to 2007, Southern Company has retired or converted to natural gas about 75 percent of its coal-fired generating units and, subject to regulatory approval, we expect further reductions in our coal fleet by 2035. However, each of those decisions was made in the context of its impacts to grid reliability and energy affordability within the applicable state regulatory framework.

The proposal maintains that EPA expects states will rarely identify a need for a standard that varies from EPA's proposed emission guidelines based on RULOF. In support of this assertion, EPA cites the "relatively long lead times and compliance time frames proposed in the emission guidelines."[17] To the contrary, the proposed compliance deadline for coal units falls less than three years after the projected date for EPA to approve state plans, which does not provide a "long lead time." In addition to time necessary for siting, engineering, permitting, regulatory approval, procurement, and construction of replacement generation, the associated transmission and reliability impacts from retirement of large central station generators will often require significant infrastructure upgrades which render EPA's proposed deadlines infeasible.

States' implementation of the emissions guidelines will require significant flexibility in tailoring unit-specific retirement timing and operational constraints to address real-world concerns, such as grid reliability impacts, physical and technical challenges, and overall schedule and cost feasibility.

EPA should clearly acknowledge the authority of states, as part of their authority to consider RULOF, to adjust unit-specific time frames and operational constraints. For example, some units may be required to run to provide grid reliability support, such as voltage regulation, for periods extending beyond the retirement dates that EPA has proposed. EPA should make clear that states have the flexibility to tailor the application of performance standards to reflect

[17] 88 Fed. Reg. at 33,384.

appropriate unit retirement dates and operational constraints to provide adequate time for utilities to complete all of the steps necessary for construction and commissioning of replacement generation facilities and associated infrastructure to maintain grid reliability.

Georgia Power's Plant Bowen coal-fired power plant is a good example of a situation where significant flexibility is needed for the state to determine an appropriate standard of performance and compliance pathway. Plant Bowen is one of the largest power plants in the country with a net nameplate capacity of approximately 3,200 MW. Due to its location and size, replacing the generation capacity of Plant Bowen would require both significant new transmission development and generation replacement. Georgia Power currently anticipates that the necessary transmission projects and additional generation to replace Plant Bowen while maintaining reliability could require timelines through the end of 2035, including completion of the robust state regulatory approval process and associated RFP (request for proposals) and certification processes.

While certain extensive transmission projects are already underway to allow for the eventual retirement of Plant Bowen, the acceleration of the timeline is not possible. With numerous individual transmission projects required, coordinated planning for the timing of construction and outages is critical to maintain reliability for customers throughout the process. Even if critical factors, such as supply chain, labor, and transmission and generation outage planning needs are ignored, the acceleration of the timeline would require even more extensive transmission work than currently underway, almost doubling the cost (from approximately half a billion dollars to approximately one billion dollars). And yet, doubling the cost still does not make the timeline achievable when all factors are appropriately considered. Until the completion of this transmission work, operation of Plant Bowen remains critical to maintaining electric service reliability in Georgia. As such, imposing the requirements of the proposed "near-" or "imminent-term" subcategories for existing coal-fired EGUs on Plant Bowen could increase grid reliability risks.

Further, procuring and/or building replacement generation to prepare for the eventual retirement of approximately 3,200 MW of dispatchable capacity at Plant Bowen has critical timing considerations, and the proposed rules add significant uncertainty to the timelines and cost of new resources. The regulatory processes, including any requests for replacement capacity, procurement of equipment, and certification, span several years. Meanwhile, the expected load growth in the Southeast will only increase the complexities of market supply and demand for electricity, even without the additional pressures from the proposed rules. Taking all these relevant factors into

consideration, the end of 2035 is the earliest feasible and responsible date to consider for the retirement of Plant Bowen to maintain reliability and resiliency of the electric grid in north Georgia and affordability for customers. EPA should affirm that states are in the best position to assess these factors in establishing 111(d) standards for sources within their jurisdiction.

Similarly for Alabama Power's Plant Miller coal-fired facility, in order to undertake a subcategory pathway based on early retirement of the plant, significant new transmission and replacement generation would be needed to maintain grid reliability and meet the energy needs of Alabama Power's customers. The four units at Plant Miller, which provide more than 2,500 MW of Alabama Power's dispatchable nameplate capacity, currently have planned retirement dates beyond 2040. New transmission to accommodate early retirement and/or operational restrictions for the Miller units, while at the same time maintaining grid reliability and resilience, could not be designed, permitted, approved, and constructed in time to meet the proposed compliance dates for the "imminent" or "near-term" subcategories in EPA's proposed guidelines. Further, the required new transmission capacity is not included in Alabama Power's current planning budgets or resource planning models due to the distant retirement dates currently expected for these units. Pulling those projects forward into near-term budgets would negatively impact currently planned projects and forecasted transmission budgets and introduce additional cost pressures not currently present. Further, replacement of Plant Miller's generation and capacity is virtually impossible within the "imminent" or "near-term" time frames of 2032 and 2035, respectively. In order to avoid retirement prior to 2040, EPA's proposed guidelines suggest that Plant Miller would have to significantly increase co-firing with natural gas by 2030. However, extensive upgrades to the interstate natural gas infrastructure responsible for delivering gas to the plant would be necessary to accomplish this, and the scale of these upgrades could likely not be commissioned prior to 2030, eliminating the proposed "medium-term" pathway in the proposed emission guidelines as a viable option for Plant Miller. Similarly, designing and constructing carbon capture and sequestration at the Plant Miller location would not be feasible by 2030. Importantly, based on EPA's proposed compliance schedule, the time frame for meeting the requirements of any of these pathways will likely be less than three years after EPA's proposed deadline for approval of the state plan, which is not enough time to implement CCS or natural gas co-firing.

C. EPA should support emissions averaging and provide an approvable model trading program to simplify state plan development and reduce the burden on states.

Southern Company supports well-designed trading and averaging programs, which can improve affordability, reliability, and efficiency of the ongoing fleet transition. EPA should support state plans that achieve aggregate emission reductions consistent with intended environmental outcomes, including through trading or averaging. CO_2 is a global pollutant, meaning that its potential impact is the result of cumulative emissions from sources across the globe. As such, CO_2 emissions from EGUs present no localized impacts, making regulation of the pollutant well suited for flexible compliance approaches, including long averaging times and trading. Southern Company recommends EPA's final emission guidelines make clear that states may offer a wide array of flexible options to assist existing EGUs in meeting emissions limits, including emissions averaging and trading. These flexible compliance options should be broad and allow averaging or trading among units at a plant, within a state, or in different states. EPA has recognized that these types of market-based tools "have proven to be extremely effective" and "can achieve substantial reductions in pollution."[18] Analysis has also shown that these types of programs do not disproportionately burden environmental justice communities.[19]

Southern Company encourages EPA to allow states to choose the compliance structure that works best for the units within their state and with their state plan. Although, historically, emissions limitations in section 111 rules are typically based on the amount of emissions per unit of output or input (e.g., lb/MWh), a mass emissions limitation option may offer advantages in certain circumstances with regard to regulating CO_2 emissions from existing fossil fuel-fired EGUs. For example, incorporating a mass-based trading program or facility averaging into a state plan can be more straightforward than a lb/MWh rate-based approach.

Existing units with less stringent emissions standards developed under RULOF should be eligible to participate in any trading or averaging program to achieve their unit-specific emission limit. If the overarching goal of EPA's proposal is to reduce total emissions within a state or region, this goal will be achieved even if a trading program adopted by a state reflects an individual

[18] EPA, *What is Emissions Trading?*, https://www.epa.gov/emissions-trading-resources/what-emissions-trading, last updated June 27, 2022.

[19] *See, e.g.*, California Air Resources Board, FAQ Cap-and-Trade Program, https://ww2.arb.ca.gov/resources/documents/faq-cap-and-trade-program.

source's standard of performance that accounts for RULOF. Likewise, over-compliance by a RULOF unit should be recognized as an opportunity for efficiency and not presumed to indicate any fault in the RULOF standard.

In the preamble to the proposed rules, EPA suggests numerous concerns and constraints regarding a state's ability to implement trading or averaging programs. Given the uncertainty of what EPA would consider is an approvable averaging or trading program to be included in state plans, it is unlikely many states (if any) will be willing to expend resources in developing such programs from scratch. Southern Company encourages EPA to provide a model trading program that states could use or adapt as part of their state plans that is well-designed and flexible and includes presumptively approvable state budgets with provisions to account for RULOF considerations. EPA provided a presumptively approvable trading program previously with the Clean Air Mercury Rule (CAMR) and should do so again here. Although CAMR was vacated by the U.S. Court of Appeals for the D.C. Circuit, the reasons for that vacatur had nothing to do with the model trading program. If implemented with a sound design and flexibility, there are many advantages to this approach. States would have a simple option to include the program in an approvable state plan and would benefit from this certainty, which may allow them to expend fewer of their limited resources on an extensive case-by-case analysis of each affected facility within their jurisdiction. And for those states that want to maximize the compliance options available to the affected sources within the state, this approach would provide a trading framework that would enable cooperation with other states.

In a model trading program, EPA should consider offering incentives to reward early action and to ensure credits remain for some period of time after units shut down. EPA has done this with other trading programs and should do so here. EPA should propose a model trading program as expeditiously as practicable to ease the regulatory burden on states and provide certainty to the regulated community.

D. EPA should allow states at least 36 months for state plan development.

In light of the critical factors discussed above and throughout these comments, the development of state plans for existing EGUs will be uniquely complex, particularly because the determination of emission limits for each existing EGU is expected to be highly unit-specific and fact intensive. The proposal sets strict requirements that must be followed with regard to

meaningful engagement with specific stakeholders, and states need to be given adequate time to both perform the analysis necessary to establish and implement standards of performance for affected EGUs and to meet the public engagement requirements, which include outreach to a diverse set of stakeholders, including local communities. For these reasons, Southern Company respectfully suggests that states need at least 36 months to develop state plans after EPA finalizes its emission guideline.

III. EPA SHOULD MAKE REFINEMENTS TO COMPLIANCE TIMELINES AND SUBCATEGORIES TO SUPPORT THE ONGOING ENERGY TRANSITION.

While some conceptual elements of the proposal align with the ongoing energy transition, many of the detailed provisions include infeasible compliance and implementation timelines that should be revised to recognize needed lead times, align with other EPA rulemakings (e.g., Supplemental ELG), and to support the power sector's orderly fleet transition while maintaining a reliable and affordable electric system.

The compliance deadlines in EPA's section 111 proposal fall within critical points in time for maintaining grid reliability while meeting growing customer needs in the Southeast. For the utility industry, significant load growth is expected in the next five to ten years and beyond as economic activity continues to increase and other sectors of the economy accelerate electrification. By setting compliance requirements that will add new risks and uncertainties to generation and transmission planning, EPA's proposal threatens to disrupt and adversely impact our ability to cost-effectively address future customer needs. Southern Company's 2050 net-zero goal considers the importance of moving at a pace that is supported by technology and infrastructure advancement and recognizes the need to maintain flexibility for needed adjustments as the industry evolves. EPA can support an efficient net-zero transition by providing additional time for compliance and by ensuring compliance flexibilities are available if needed.

In addition to considering the time required for engineering, siting, permitting, regulatory approval, procurement, and construction of new generation to both replace retiring units and serve growing electric loads, any new rules designed to drive material changes to the power sector must also factor in timing constraints associated with required new pipeline and transmission infrastructure. Notably, multiple individual transmission projects are often required to support the retirement or addition of a single large central station electric generating facility, and the transition

process requires careful planning and coordination for unit outages and commissioning to address grid reliability concerns.

When additional critical factors, such as supply chain and labor constraints, are considered, there is a practical limit on the amount of new generation, transmission, technology, and pipeline infrastructure that can be added within a defined time window. These additional schedule constraints are likely to be exacerbated when the entire power sector is pursuing similar projects within the same short window of time. Supply chain constraints are a critical concern for electric utilities and can significantly impact the cost of critical equipment and add significant delay to construction timelines. The recent challenges regarding procurement and installation of transformers provide a directly relevant example of supply chain pressures that can adversely affect costs and timing for important electric utility industry infrastructure projects. For example, due to workforce shortages and other supply chain issues, both exacerbated by the COVID-19 pandemic, the time to procure distribution transformers has risen from a few months to more than a year, and costs have tripled.[20], For large transformers that are needed for the bulk power system, the backlog has grown to as much as three years. This type of supply chain issue is especially concerning for nascent technologies, such as CCS, where equipment supply chains are not mature and there are only a few vendors available to supply the technology.

The proposed subcategories for new and existing EGUs include capacity factor thresholds and retirement of units that are effectively alternative pathways for compliance, especially if installation of one of the CO_2 emission reduction technologies is infeasible or cost-prohibitive for a facility. However, when generating units are restricted to operate under specified capacity factor limitations, additional generating resources are required to provide the energy necessary for system reliability, especially during an era of increasing electricity load. This can result in increased cost due to the larger amount of generating capacity required for system reliability.

For example, the proposal potentially constrains the most efficient type of dispatchable, flexible generation resources, natural gas combined cycles, which have advantages of flexible operations and load ramp capabilities that can support transmission voltage regulation and demand

[20] *Utilities sound alarm over distribution transformer shortage as procurement times surpass 1 year and costs triple*, Utility Dive (December 19, 2022) https://www.utilitydive.com/news/distribution-transformer-shortage-appa-casten/639059/; *Electric Power Transformers: Supply Issues*, Congressional Research Service, (Nov. 16, 2022) https://crsreports.congress.gov/product/pdf/IN/IN12048/2.

fluctuation. Plant McDonough, located in Atlanta, Georgia, is a prime example of a strategically located dispatchable resource that supports the largest load center in the state with efficient electricity production and provides critical regulating capabilities to support transmission reliability. Because of their efficiency and the value of their flexible operations, natural gas combined cycles like those at Plant McDonough are expected to operate at high capacity factors for the foreseeable future. Constraining these resources to a roughly 50 percent capacity factor, which is suggested as a compliance pathway in the proposal for large and frequently operated existing combustion turbines that have no feasible option to implement CCS or hydrogen co-firing within the proposed time frames, means both lost energy and lost flexibility to support reliability because the generating characteristics of these units cannot be replaced by renewables, such as wind and solar. Because the proposal is based on EPA's determination that CCS and hydrogen technology choices are widely available and cost-effective, the proposal does not adequately contemplate these potential costs.

For these and other reasons discussed below, we ask EPA to extend the proposed compliance deadlines and increase the proposed capacity factor and capacity thresholds for subcategories to avoid disruption to the ongoing orderly fleet transition to net-zero emissions and help ensure the reliability and affordability of electricity for customers.

A. EPA should anchor proposed compliance timelines for existing source subcategories to the date of state plan approval.

EPA's proposed compliance deadline for existing fossil fuel-fired EGUs does not adequately account for the complexities of the detailed analyses that are needed to support state plan development, the robust regulatory decision-making processes that require utility commission review and approval, and the time needed to design, construct, and commence operation of new control technologies or replacement generation, transmission, and pipelines. EPA requests comment on its proposed compliance dates, which are anchored to the date the final rule is issued.[21] Southern Company recommends, instead, that EPA anchor the compliance time frames for existing sources to the date of state plan approval.

[21] 88 Fed. Reg. at 33,372.

EPA is proposing for compliance to begin on January 1, 2030, for all existing coal-fired EGU subcategories. EPA notes in the proposal that it expects final emission guidelines for existing fossil fuel-fired EGUs to be published in June 2024 and is proposing a state plan submission deadline 24 months from publication (i.e., June 2026).[22,23] The proposed subpart Ba rule,[24] which includes updates to the 111(d) implementing regulations, would allow EPA 60 days from the date of submittal to determine whether the state plan is complete and would require EPA to approve or disapprove the state plan within 12 months of the completeness finding. This means that affected units would have less than 2.5 years to install and begin operation of new control technologies after learning whether EPA approves of the state's plan.[25] However, EPA recognizes that CCS implementation will take longer than this, estimating that "CCS projects will take roughly five years to complete,"[26] essentially twice the time remaining after the point at which a state plan becomes federally enforceable.

EPA expects that some initial evaluation and planning steps for both natural gas co-firing and CCS would take place as part of the state plan development process.[27] EPA states that, for units in the long-term coal-fired EGU subcategory, "[t]he time available before the compliance deadline of January 1, 2030, provides for adequate resource planning, including accounting for the downtime necessary to install the CO_2 capture equipment at long-term coal-fired steam generating units."[28] While it may be true that some initial evaluation is likely to take place during the state plan development process, any investment in the extensive work that is needed for project development, such as engineering, permitting, and site development, would be subject to the risk of EPA's disapproval of the state plan that served as the basis for the work. This also holds true for installation of natural gas co-firing, accelerated unit retirement, and reduced utilization requirements.

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[22] *Id*.

[23] EPA's Spring 2023 Regulatory Agenda indicates that EPA plans to issue a final rule in April 2024. (S*ee* https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=202304&RIN=2060-AV09.)

[24] 87 Fed. Reg. 79,176 (Dec. 23, 2022).

[25] Units would have even less time if EPA misses its deadline for approving or disapproving state plans.

[26] 88 Fed. Reg. at 33,402.

[27] *Id*. at 33,372.

[28] *Id*. at 33,349.

Detailed analyses are needed to support state plan development (including the extensive community engagement that the proposal requires of states). Utilities will be required to engage with public service commissions and other regulatory agencies on the state plan implementation, including any decisions on retirements, installation of retrofits, and/or building new generation for replacement capacity and energy and to meet growing electricity demand. State plan development is a lengthy and complex process, particularly because the determination of emission standards for each EGU may be highly unit-specific and fact intensive. States also need sufficient time to engage with a diverse set of stakeholders, including local communities.

EPA should fully consider the timing of resource decisions, including state regulatory processes, which are critical for utilities. The processes required for an efficient, coordinated, cost-effective fleet transition, including unit retirements and construction of new generation, transmission, and pipeline infrastructure, will necessarily involve time frames extending beyond the proposed compliance deadlines. For example, retrofitting coal units in the proposed medium-term subcategory to add 40 percent natural gas co-firing capability will require multiple interrelated activities, including, but not limited to, the following:

Activity	Estimated Time Frame[29]
Air Permitting	12 to 30 months
FERC Permitting for pipeline	36 to 48 months
Pipeline Engineering, ROW/easements, Procurement and Construction	24 to 48 months
Public Service Commission Approval	12 to 18 months
Facility Engineering, Procurement and Construction	30 to 36 months

While some of these activities can be done concurrently rather than sequentially, for preliminary planning purposes the overall generic time frame to retrofit an existing coal unit for 40 percent natural gas co-firing is estimated at 6 to 7 years. Actual project schedules will be site-specific, depending on the extent of needed interstate natural gas pipeline expansion, current market conditions, project location, public opposition, and other factors.

The indicative project schedule to retrofit an existing coal unit with CCS involves activities similar to those noted above, with the additional scope and schedule required for CO_2 pipeline permitting and construction, along with permitting and construction activities related to

[29] The estimated time frames for the listed activities could be longer in some circumstances.

sequestration of the captured CO_2. In sum, the overall generic time frame required to retrofit an existing coal unit with CCS is estimated at 7 to 9 years. Actual project schedules will be site-specific, depending on current market conditions, geographic and geologic location, public opposition, and other factors.

For new and existing gas resources, the indicative project schedule for CCS includes, but is not limited to, the following activities:

Activity	Estimated Time Frame[30]
Project Development and Permitting (e.g., air, water)	22 to 48 months
RFP and Public Service Commission Approval	24 to 36 months
Pipeline Permitting	36 to 48 months
Pipeline Engineering, ROW/easement, Procurement and Construction	24 to 48 months
Facility Engineering, Procurement and Construction	42 to 60 months

As with natural gas co-firing retrofits, some of these activities can be done concurrently, so the indicative schedule for preliminary planning purposes for new and existing combined cycle with CCS generation facilities is 8 to 10 years. As noted above, the actual project schedules will be site-specific, depending on current market conditions, geographic and geologic location, community and stakeholder engagement, and other factors.

These types of fleet transition projects, where large central station generating facilities are retired and new generation is added, will require significant coordination of transmission infrastructure construction/modifications and unit outages and commissioning to ensure continued system reliability. This component of project-specific planning schedules is not reflected in the generic planning project time frames cited above and can have material impacts to any particular project involving transmission and unit outage/commissioning coordination, particularly in circumstances involving multiple projects within a region.

Importantly, utility commission approval will be required for regulated utilities to move forward with the significant changes that would be required by the proposal, potentially including new generation plans, environmental compliance plans for existing units, unit retirements, transmission projects, RFPs, and other interrelated activities, which will necessarily be predicated on the scope of work required to comply with an EPA-approved state plan. Hence, for existing

[30] The estimated time frames for the listed activities could be longer in some circumstances.

units, these project timelines cannot substantially move forward prior to the date of EPA's *approval* of the state plan.

As an illustration of the critical timing considerations of state regulatory processes, Georgia Power is required to complete extensive planning analyses as a vertically integrated utility regulated by the Georgia Public Service Commission (PSC).[31] The Georgia PSC oversees and must approve of planning and resource decisions to ensure Georgia Power can meet its obligation to serve its customers, including ensuring Georgia Power maintains sufficient capacity to reliably serve load during periods of peak energy demand. Georgia Power is required under its state PSC regulations to act prudently in its investment and compliance decisions. Those decisions are reviewed as part of statutorily required, triennial IRP proceedings, subject to PSC review and approval, which comprehensively evaluate Georgia Power's plans for the next 20 years. The IRP process allows interested members of the public the right to participate in multiple ways, including engaging in the thorough review of Georgia Power's plans by intervening in the case or providing comments during a public hearing.

Decisions on how best to meet the needs of Georgia Power customers are not relegated to a singular analysis. Georgia law acknowledges this by requiring a planning process that is truly integrated and recognizes the supply-side dynamics of forecasted needs, transmission, environmental compliance, and generation. The development of the IRP is a complex process requiring coordination across Georgia Power that takes significant time to complete. As a part of each three-year planning cycle, planning for and preparing the IRP takes a year or more, the IRP and any subsequent rate case proceedings take another year, and the continued implementation of the PSC decisions is the focus of the following year and beyond. Through the IRP process, Georgia Power ultimately submits to the PSC its long-term plan to meet the needs of customers by providing reliable, cost-effective electricity while also complying with a range of environmental laws.

Given this regulatory framework, Georgia Power must carefully evaluate the implications for operations, reliability, and the impacts on customers through the IRP process when considering environmental compliance strategy decisions to control or retire and replace generating resources. To modify its generation portfolio, Georgia Power must follow PSC rules which, for large

[31] O.C.G.A. § 46-2-20(a).

resources, requires Georgia Power to issue RFPs, evaluate RFP bids, and apply for certification of new resource(s) with the PSC. To receive approval of a certification request, the utility must ensure prudency of the RFP process, which necessitates a thorough and equitable evaluation. The PSC required RFP and certification time frames applicable to Georgia Power typically require between 19 and 30 months before resources are certified or activities associated with building a new resource can be initiated. Up to six months of additional time may also be required prior to the certification filing depending on the level of activity at the PSC and whether certification requests will be included as part of an upcoming triennial IRP filing. Of special note is the fact that Georgia law prohibits an electric utility from commencing construction until a certificate is obtained from the PSC. With the robust regulatory process that is required by law, any decision to retire a generating unit requires a multi-year evaluation to ensure that customers' best interests are fully considered.

EPA must consider these lengthy state regulatory process requirements in establishing any guidelines around timelines for installation of control technologies or unit retirement commitments.

B. The required schedule for widespread utility-scale deployment of CCS will extend beyond the proposed 2030 compliance deadline.

CCS is an integrated suite of technologies that has the potential to work together to capture (separate and purify) CO_2 from stationary source emissions, compress and transport it to a suitable location, and then either use it or inject it into deep underground geologic formations for safe, secure, and permanent storage. Southern Company manages and operates the National Carbon Capture Center (NCCC) located in Wilsonville, Alabama, and has participated in two of the six projects that are the subject of detailed Front-End Engineering and Design (FEED) studies with the DOE.[32] We promote a collaborative environment where approximately 150 highly specialized engineers, operations, maintenance and support staff, and construction personnel take projects

[32] The NCCC is funded through a collaborative agreement with DOE's Office of Fossil Energy and National Energy Technology Laboratory, as well as through sponsorship agreements with leaders in the energy industry who provide cost- sharing, consultancy, and technical guidance. As a neutral research facility, the NCCC is working to accelerate the commercialization of advanced technologies to reduce GHG emissions. Since its creation by the DOE in 2009, the center has become a cornerstone of U.S. innovation in the research and development of cost-effective, technically viable carbon capture technologies.

through onboarding, design, scale-up, testing, data analysis, final evaluation, and demobilization. We also share knowledge with developers and test facilities as technology is scaled up following testing at the NCCC.

The Inflation Reduction Act (IRA) includes incentives to further this technology development through increased tax credits available for CCS projects. The IRA provides credits of $85 for each metric ton of CO_2 stored in secure geologic formations and $60 for each metric ton of CO_2 used for enhanced oil recovery and injected into secure geologic storage or used in a qualified manner.[33] This is a significant increase from the amounts previously available under the tax code, and while these funds should help spur development of CCS technology, widespread utility-scale deployment of CCS technology is years away.

CO_2 capture on a small scale has been happening for many years in the petroleum, ethanol, and industrial chemical industries. While deployed in these industrial sectors for commercial uses, the technology has not been deployed to date at utility-scale as an environmental control technology, where reliability and consistent performance over a broad range of operating conditions are paramount requirements to ensure compliance with regulatory standards and permit conditions.

Technology testing at the NCCC and the Technology Centre Mongstad (TCM) (located in Mongstad, Norway) has been valuable to evaluate carbon capture technologies and move them through the development curve to prepare them for demonstration. Several technologies that have been tested at those facilities are now in the FEED stage, which will refine the expected costs of those options. A technology needs to be demonstrated at a scale above the level currently achieved by the NCCC or TCM, however, to identify and address operational, maintenance, and reliability issues before being considered commercially available. Continued public/private partnerships with the DOE will be critical to reduce risk to electric customers through technology development at test centers and eventual demonstration at commercial scales.

There are only two examples of CCS at commercial EGUs in North America, both of which are coal-fired: the Boundary Dam project in Saskatchewan, Canada, and the Petra Nova project in Texas. Boundary Dam is a 115 MW coal-fired EGU capable of capturing up to 90 percent of its CO_2 emissions using an amine solvent. While Boundary Dam has captured over four million metric

[33] Pub. L. No. 117-169, § 13104(c).

tons of CO_2 since carbon capture operations began in 2014, it has experienced equipment issues that have negatively impacted the unit's ability to consistently capture CO_2.[34] The Petra Nova project was designed to capture 90 percent of the CO_2 emissions from a 240 MW slip stream from a 610 MW coal-fired EGU (approximately one-third of the unit's CO_2 emissions) to be used for enhanced oil recovery. During the three years Petra Nova operated, it experienced outages on 367 days, with the CCS facility accounting for more than one-fourth of those outages.[35] Both the Boundary Dam project and the Petra Nova project demonstrate the need for continued efforts to not only reduce both capital and operational costs for CCS, but also improve operating reliability and performance, which are critical when facilities are required to maintain grid reliability and simultaneously meet regulatory emission limits.

As part of the Infrastructure Investment and Jobs Act (IIJA), which was signed into law in November 2021, Congress authorized funding for the DOE's Carbon Capture Demonstration Projects Program, investing $2.537 billion to "fund domestic commercial-scale CCS demonstration projects designed to further the development, deployment, and commercialization of technologies to capture and geologically store carbon emissions."[36] In September 2022, DOE's Office of Clean Energy Demonstrations issued a Funding Opportunity Announcement (FOA) soliciting proposals for CCS demonstration projects at new or existing coal and natural gas electric generation facilities, as well as industrial facilities.[37] The FOA also outlined a subsequent FOA yet to be issued that would include three additional phases of effort, including 1) project development, permitting and financing, 2) installation, integration, and construction, and 3) ramp-up and sustained operations. Based on the information provided in the FOA and the experience of our Research and Development Team at Southern Company, we anticipate that ramp-up and sustained

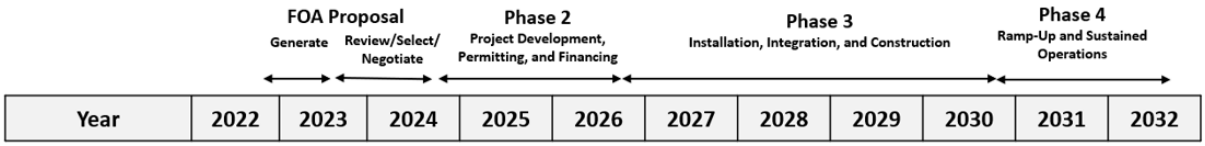
[34] Geoff Leo, *SaskPower Looking for Help to Fix 'High Cost' Boundary Dam Carbon Capture Flaw*, CBC NEWS (May 28, 2018), https://www.cbc.ca/news/canada/saskatchewan/saskpower-looking-for-help-to-fix-high-cost-boundary-dam-carbon-capture-flaw-1.4680993.

[35] Nichola Groom, *Problems Plagued U.S. CO_2 Capture Project Before Shutdown: Document, Reuters* (Aug. 6, 2020), https://www.reuters.com/article/us-usa-energy-carbon-capture/problems-plagued-u-s-co2-capture-project-before- shutdown-document-idUSKCN2523K8.

[36] https://www.energy.gov/oced/carbon-capture-demonstration-projects-program.

[37] Funding Notice: Bipartisan Infrastructure Law: Carbon Capture Demonstration Projects Program | Department of Energy, https://www.energy.gov/fecm/funding-notice-bipartisan-infrastructure-law-carbon-capture-demonstration-projects-program#:~:text=On%20September%2023%2C%202022%2C%20the,projects%20that%20can%20be%20readily.

operations for these first demonstration projects will occur in the 2030 to 2032 time frame, assuming there are no significant project delays (see graphic below).



In addition to the technology demonstration concerns discussed above, commercial deployment of CCS includes numerous other important considerations. First, captured CO_2 must be permanently stored in suitable geologic formations. Unless captured CO_2 is used or stored at the capture site, it must be transported to other locations with adequate geology. Not all regions of the U.S. have adequate geology, including portions of our retail electric operating companies' service territories. While EPA finds that there are "43 States with access to, or are within 100 km from, onshore or offshore storage,"[38] the proposal does not evaluate the amount of actual available area within each state nor whether the specific geographic locations are suitable for generation considering load centers, gas pipelines, and transmission needs. Further, there is no regulatory permitting framework for offshore storage in Federal waters, which currently precludes those areas as potential storage sites. Several plants in the Southern Company service territory, such as Plants Bowen (Georgia) and Miller (Alabama), are expected to require CO_2 pipelines that could extend over 249 km to reach suitable storage sites based on current knowledge. In Georgia, a state without an oil and gas exploration and production industry or opportunities for enhanced oil recovery, what little is known about the geology in the state suggests that the potential for geologic storage is limited. Currently, a national CO_2 pipeline network does not exist outside of CO_2 for enhanced oil recovery, which presents challenges for deploying this technology in many areas of the country. Further, of the new CO_2 pipelines that are planned or announced, none are located within our service territories, leaving many sites of new and existing dispatchable generation without reasonable access to geologic storage sites. These circumstances not only suggest significantly increased costs and time to build CO_2 transportation infrastructure that are not contemplated by the proposal, but also raise questions about practical feasibility.

[38] 88 Fed. Reg. at 33,347.

Another concern with CCS is ownership of and legal rights to access "pore space." When CO_2 is pumped into a geologic formation, it occupies small voids within the geologic structure known as "pore space." Before pumping CO_2 into the subsurface, the storage operator must secure the property rights to access the pore space. However, pore space ownership rights vary state-by-state and, in some instances, have not been legislatively or judicially established (e.g., Alabama, Georgia, or Mississippi), which presents challenges for CO_2 storage projects. Entities developing CO_2 sequestration projects typically need to seek permission from multiple landowners to use pore space. These projects often extend over numerous tracts (and jurisdictions) and affect other entities with various interests in the property, such as competing uses of subsurface mineral rights. In some instances, the developer may need to seek approval from, and compensate, the owner(s) of the mineral estate that the project will utilize. Also, land with property rights that are without limitation or conditions may not be available. Access to pore space is critical to CCS development, and obtaining the necessary property rights can be complex and challenging, especially for storage projects involving multiple landowners.

In addition to property rights issues affecting CCS, there are also long-term liability considerations associated with the stored CO_2. Some states have enacted laws agreeing either to assume liability for stored CO_2 after a period of years if certain conditions are met, or to release the storage facility owner/operator from liability after a certain period, again subject to conditions. The purpose behind these laws has been to encourage CCS project development, but not all states have enacted such laws, and varying state approaches can be a challenge for projects crossing state boundaries.

Another challenge to deployment of CCS is the time frame for the required permitting of Class VI wells for injection of CO_2 for permanent geological storage. Currently, the permitting process to receive approval from EPA for a Class VI Underground Injection Control (UIC) permit for CO_2 storage takes years.[39,40] These long permitting lead times create project risk and uncertainty and can affect third-party financial investment. Additional federal resources, as well

[39] Mayer Brown, Carbon Capture, Utilization, and Storage: Class VI Wells and US State Primacy, https://www.mayerbrown.com/en/perspectives-events/publications/2022/06/carbon-capture-utilization-and-storage-class-vi-wells-and-us-state-primacy.

[40] U.S. Environmental Protection Agency UIC Class VI Permitting Report to Congress (Oct. 28, 2022), https://www.epa.gov/system/files/documents/2022-11/EPA%20Class%20VI%20Permitting%20Report%20to%20Congress.pdf.

as expedited EPA review and issuance of state primacy applications, are needed to accelerate this process and encourage more project development.

Southern Company believes that CCS is a promising technology that is making great strides. We have long been a supporter of CCS technology and have been at the forefront of its development. We are encouraged by the funding and tax incentives included in the IIJA and the IRA and expect the economic support included in these laws to be instrumental in moving this technology farther along the development curve. However, given the challenges around technology demonstration, permitting, infrastructure construction, transport, and storage, widespread utility-scale deployment of CCS technology is years away, likely extending well beyond the proposed 2030 compliance deadline.[41]

C. EPA should make refinements to the proposed emission guidelines for existing coal-fired EGUs.

1. The proposed compliance deadline for the long-term coal-fired EGU subcategory should be extended by at least six years.

EPA's proposed emission guidelines include a long-term existing coal-fired EGU subcategory that applies to units with no commitment to retire. The proposed BSER for this subcategory is based on CCS with 90 percent carbon capture with a degree of emission limitation of 88.4 percent reduction in CO_2 emission rate.

As noted earlier, EPA is proposing for compliance to begin on January 1, 2030, for the coal-fired EGU subcategories, which provides less than 2.5 years to implement CCS after the deadline for state plan approval. For the reasons detailed in Section II.B., the time frame to design, permit, construct, and implement CCS will require a deadline at least six years beyond the proposed January 1, 2030, deadline. EPA should extend the proposed compliance deadline for long-term existing coal units by at least six years and no earlier than December 31, 2035.

[41] As noted in Section III.B., Congress has directed substantial funding to DOE to pursue demonstration of CCS technology for commercial-scale application. We anticipate that these first demonstration projects will occur in the 2030-2032 time frame.

2. The proposed compliance deadline for the medium-term coal-fired EGU subcategory should be extended by at least six years.

EPA proposes a medium-term existing coal-fired EGU subcategory that includes units that commit to retire after December 31, 2031, and before January 1, 2040, and that do not commit to adopt an annual capacity factor limit of 20 percent beginning January 1, 2030 (i.e., the unit is not in the near-term coal-fired EGU subcategory). EPA proposes that the BSER for these units is co-firing natural gas at 40 percent with an associated emission limitation of 16 percent reduction in emission rate.

Since 2007, Southern Company has converted over 3,800 MW of nameplate capacity of coal-fired generation to utilize lower-carbon natural gas as the primary fuel. Southern Company continues to evaluate natural gas conversion of its remaining coal units as one of many alternatives to facilitate the ongoing transition to a net-zero GHG emissions electric generation fleet, with the priority objective of maintaining a clean, safe, reliable, resilient, and affordable energy supply for our customers over the long term. While additional coal-to-gas conversions and higher rates of natural gas co-firing at some coal units may occur in certain situations, the unavailability of existing natural gas pipeline transportation and other unit-specific considerations will constrain the timing and overall viability of significant industry-wide natural gas co-firing or additional natural gas conversions.

Many remaining coal-fired EGUs have limited or no existing capability for gas co-firing. For units with limited natural gas co-firing capability, natural gas is typically used only for startup and flame stabilization. These plants will require physical modifications (e.g., additional gas burners, boiler modifications) along with additional gas delivery to provide adequate gas pressure and volume needed for gas co-firing.

The technical and economic viability for existing coal units to convert to or co-fire natural gas is site- and unit-specific, with the timing, cost, and degree of gas co-firing capability dependent upon numerous factors, such as existing gas burner capacity (if any), along with cost and time for any required burner upgrades or retrofits; availability of a reliable, economic gas supply for the plant site, including consideration of existing pipeline capacity and available firm gas transportation; time and cost for any permitting for the addition of gas capacity; permitting and construction required for necessary main pipeline expansions (if feasible); and existing gas

delivery infrastructure for the facility (e.g., gas lateral capacity) and/or the need for new infrastructure.

An important consideration for natural gas co-firing is that the capacity of the pipeline transportation system must be large enough to manage large volumes of natural gas consumption. If natural gas co-firing were to be applied at two coal-fired EGUs located relatively near each other, such as Alabama Power's Plant Miller and Georgia Power's Plant Bowen, these plants may need to utilize a substantial volume of natural gas at the same time. To preserve pipeline stability, upgrades (e.g., compression stations and pipeline expansion) would be required on the main pipeline system. Without upgrades to the pipelines, other plants up and down the pipeline system would likely be adversely impacted by the new demand from co-firing at coal units. The July 28, 2023, North American Energy Standards Board's (NAESB) Gas Electric Harmonization Forum Report notes a lack of any "comprehensive regional assessments…that examine…[the sufficiency of] natural gas infrastructure to support new usage patterns…." This report highlights the need for policy makers to evaluate and understand challenges with regard to the adequacy of current natural gas infrastructure "so that they can make informed policy decisions and take steps to avoid any potential reliability and resilience risks that accompany the transition to a lower emissions energy future."[42]

Furthermore, EPA's analysis of co-firing natural gas at existing coal-fired EGUs appears to assume natural gas is purchased from the market (e.g., Henry Hub) as needed and that the amount of pipeline capacity that is required to transport the gas to the plant is immediately available. However, pipeline capacity is not always available. Relying on pipeline transportation capacity to be available as needed does not ensure an adequate amount of pipeline transportation will be available during critical periods of operation, such as extreme cold winter weather events, and can significantly impact grid reliability. Firm transportation (FT) contracts for pipeline capacity help provide some level of assurance that pipeline transportation capacity is available when it is needed. However, pipelines that serve the Southern Company service territory are nearly fully contracted for their transportation capacity during critical winter months, making it costly and challenging to acquire additional FT. For pipeline companies to expand their systems to provide additional FT, a pipeline expansion project would need to be filed with FERC, permitted,

[42] https://www.naesb.org/pdf4/geh_final_report_072823.pdf.

and constructed. This process alone can take four to five years or, in some cases, much longer, depending on the size and complexity of the project. For example, the Mountain Valley Pipeline project, a natural gas pipeline system that, when completed, will span approximately 303 miles from northwestern West Virginia to southern Virginia, began before October 2015 and is still not online today.[43] EPA should consider both the time and cost of additional FT for co-firing natural gas at coal-fired EGUs, including the likely need for large cross-state pipeline expansion to support the additional gas consumption.

In many cases, in order to co-fire natural gas on a coal-fired EGU, a new pipeline lateral from the pipeline main line to the plant will also need to be constructed. This process will require state regulatory approval as well as environmental and construction permits. Depending on the overlap with the FERC process described above, and how much cost would be put at risk to build the lateral before the mainline is expanded, this process can take additional time to build the necessary lateral to the plant.

The overall time frame to secure state plan approval, state PSC approvals, procure permits, secure gas supply, and construct the necessary infrastructure renders the January 1, 2030, deadline for natural gas co-firing infeasible. EPA should extend the proposed deadline for medium-term coal-fired EGUs to begin co-firing 40 percent natural gas by a minimum of six years and no earlier than December 31, 2035.

3. The proposed capacity factor limitation for the near-term coal-fired EGU subcategory should be increased.

EPA is proposing a near-term coal-fired EGU subcategory for coal-fired units that commit to retire by January 1, 2035, and will operate with a capacity factor that is less than 20 percent beginning January 1, 2030. In many cases, coal-fired units that will retire in the mid-2030s are critical for reliability through the fleet transition. In addition, as previously discussed, the transmission system will require upgrades and additions to accommodate unit retirements and resource additions. It is likely that key transmission system elements will be taken out of service for extended periods to complete the upgrades. When this occurs, certain points in the transmission system will have voids that can only be mitigated by generation in key areas. Given that coal retirements are associated with the need for the upgrades, it is likely that additional runtime from

[43] https://www.mountainvalleypipeline.info/overview/.

coal units will be required to support the grid while upgrades are installed. This additional runtime is likely both in off-peak maintenance periods and periods of high grid demand.

For these reasons, we recommend that EPA increase the proposed capacity factor threshold for the near-term coal-fired EGU subcategory to at least 30 percent.

D. The proposed compliance deadline for the hydrogen pathways for new and existing combustion turbines should be extended by at least five years to make this pathway a more realistic option.

EPA is proposing a "base load" subcategory for new combustion turbines that includes units that operate at a capacity factor greater than the unit's design efficiency and is proposing a phased approach for applying performance standards to units in this subcategory. In the first phase, EPA proposes a BSER based on highly efficient combined cycle operation that would apply when a new combustion turbine comes online (prior to the earliest phase 2 compliance date). EPA proposes two BSER options for the second phase for units in this subcategory – hydrogen co-firing and CCS – with separate compliance timelines. The BSER for the hydrogen co-firing pathway is based on co-firing 30 percent low-GHG[44] hydrogen beginning January 1, 2032. New base load combustion turbines selecting the hydrogen pathway would be subject to a third phase with the low-GHG hydrogen co-firing requirement increasing to 96 percent by January 1, 2038. The standard of performance that would apply during the second phase is 680 lb CO_2/MWh-gross, decreasing to 90 lb CO_2/MWh-gross in the third phase. EPA is proposing a similar pathway for "large and frequently operated" existing combustion turbines with a capacity greater than 300 MW and operating at a capacity factor greater than 50 percent, with a degree of emission limitation that is a 12 percent reduction from the baseline emission rate beginning January 1, 2032, increasing to 88.4 percent reduction beginning January 1, 2038.

Hydrogen co-firing is a promising, but still emerging, technology. Most combustion turbines used for electric generation can burn hydrogen blends of 5 to 10 percent by volume, and

[44] EPA proposes to define "low-GHG hydrogen" as "hydrogen (or a hydrogen derived fuel such as ammonia) produced through a process that results in a well-to-gate GHG emission rate of less than 0.45 kilograms of CO_2 equivalent per kilogram of hydrogen produced (kg CO_2e/kg H2), determined using the Greenhouse gases, Regulated Emissions, and Energy use in Transportation model (GREET model)." (*see* Regulatory Text – Proposed Emission Guidelines at 20, https://www.epa.gov/system/files/documents/2023-05/Regulatory%20Text%20-%20Proposed%20Emission%20Guidelines.pdf).

in certain situations, some may be capable of burning blends as high as 20 or 30 percent by volume. However, blending hydrogen is not an efficient way of reducing CO_2 emissions and has only been demonstrated in a handful of select, highly controlled situations.

Most, if not all, hydrogen co-firing demonstration projects cited in the proposal were conducted for only short periods of time with non-conforming hydrogen (i.e., not low-GHG hydrogen). For example, the demonstration at Georgia Power's Plant McDonough described in the preamble to the proposal[45] was a short-term test of a single train of a 2-on-1 combined cycle plant and required significant on-site oversight and involvement by the original equipment manufacturer (OEM) and owner during the test. The unit was operated at a maximum of around 20 percent hydrogen co-firing by volume for less than a full hour, and the test was conducted with hydrogen that would not meet the carbon intensity requirements of EPA's proposed low-GHG hydrogen.

In addition to the power sector's limited experience with co-firing hydrogen, significant concerns exist about consistent availability of hydrogen in the amounts necessary to operate a base load combustion turbine or combined cycle unit. Currently, there are a little more than ten million metric tons (MMT) of hydrogen produced in the U.S. each year, mostly through steam reformation of natural gas without CCS (which does not meet the proposal's requirements for low-GHG hydrogen). Little of this hydrogen, however, is used for electricity production. According to the EIA, "[n]early all of the hydrogen consumed in the United States is used by industry for refining petroleum, treating metals, producing fertilizer, and processing foods."[46]

Through funding from the bipartisan IIJA, the DOE has announced funding opportunities under the H2@Scale project to support DOE's Hydrogen Shot goal to drive down the cost and increase production, processing, delivery, storage, and use of clean hydrogen.[47] The DOE has set a strategic goal of producing 10 MMT of clean hydrogen in the U.S. by 2030, 20 MMT by 2040, and 50 MMT by 2050.[48] If the entire 10 MMT of clean hydrogen that is targeted for production under this goal in 2030 were used for electricity generation in combined cycle units (forgoing all

[45] 88 Fed. Reg. at 33,305.

[46] https://www.eia.gov/energyexplained/hydrogen/use-of-hydrogen.php.

[47] https://www.energy.gov/eere/fuelcells/h2scale#:~:text=H2%40Scale%20is%20a%20U.S.,revenue%20opportunities%20across%20multiple%20sectors.

[48] https://www.hydrogen.energy.gov/pdfs/us-national-clean-hydrogen-strategy-roadmap.pdf.

other industrial applications), it would only displace a little more than ten percent of current electricity consumed in the U.S. that is produced from natural gas combustion.

EPA significantly overestimates the amount of "low-GHG" hydrogen that is likely to be available in 2030 and beyond. EPA claims in the proposal that

> DOE's clean hydrogen production estimates are 10 MMT annually of clean hydrogen by 2030, and 20 MMT annually by 2040. There is reason to believe actual produced low-GHG hydrogen will exceed those levels. Announced clean hydrogen production projects total 12 MMT annually for 2030.[49]

However, this discussion in the preamble conflates EPA's definition of "low-GHG" hydrogen, which is hydrogen that is produced with a lifecycle GHG emission intensity that is less than 0.45 kg CO_2e/kg H_2, with DOE's "clean" hydrogen, which is hydrogen that is produced with "well-to-gate lifecycle greenhouse gas emissions" of less than 4 kg CO_2e/kg H_2, a GHG emission intensity of nearly an order of magnitude higher.[50]

Electrolysis is currently the most realistic pathway for producing hydrogen that meets EPA's definition of low-GHG hydrogen. Electrolytic production of hydrogen requires more than double the amount of electricity that can be generated from burning hydrogen in a combined cycle combustion turbine. For example, approximately 10,000 MW of solar power, covering an area of more than 50,000 acres, would be needed to produce enough low-GHG hydrogen to burn a 30 percent hydrogen blend at a 2,550 MW facility similar to Plant McDonough, which, in comparison, only takes up 358 acres. To increase to a 96 percent hydrogen blend, these requirements would be at least three times higher. This theoretical amount of solar power would need to be fully dedicated to producing hydrogen and would not be available to serve any other load. Because of this inefficiency, EGUs fired with electrolytic hydrogen would be expected to operate only during periods of peak demand or for system reliability and resiliency, making the entire hydrogen value chain (i.e., production, storage, transport, and power generation) simply a long-duration energy storage approach. As part of an energy storage approach, it is likely that the combustion turbines would be smaller and more distributed than current large-frame machines, and they would have to be both low cost and efficient owing to their low capacity factor and premium-priced fuel. Unless

[49] 88 Fed. Reg. at 33,364 - 65.

[50] U.S. Department of Energy Clean Hydrogen Production Standard (CHPS) Guidance (June 2023) https://www.hydrogen.energy.gov/pdfs/clean-hydrogen-production-standard-guidance.pdf.

hydrogen infrastructure is built out for other energy sectors (e.g., transportation and industry), low-GHG hydrogen will likely not be cost effective or available to use as a fuel source for base load power generation. Furthermore, deploying the gigawatts of clean generating resources that are necessary to produce the amount of low-GHG hydrogen (assuming fuel transportation is not an issue) that would be needed to support base load hydrogen-based generation would largely negate the need for those resources.

Even if an adequate supply of low-GHG hydrogen becomes available within the aspirational timeline and cost that EPA projects, other challenges remain. As EPA describes in the proposal preamble and in the hydrogen technical support document (TSD), existing and developing gas turbine technologies can support a wide range of hydrogen and natural gas blend levels.[51,52] However, technical challenges still exist that can be highly site-specific, even within the same class of gas turbine, due to different combustion system options offered by OEMs and unit configuration details. The technology developments from the major gas turbine OEMs are predominantly designed to improve the capability of modern lean premixed combustion systems to combust hydrogen. Most currently available advanced combustion systems are limited to approximately 50 percent hydrogen blends. While diffusion combustion systems can operate with much higher blends, a diluent, such as steam or water, is required to minimize the resulting high NO_x. Accordingly, site-specific water constraints should be considered.

Figure 2 in the hydrogen TSD[53] indicates that GE F-Class gas turbines are currently capable of firing 100 percent hydrogen. This information could be misconstrued without further discussion of the combustion system type and the balance of plant-related implications for such high hydrogen co-firing levels. Furthermore, unit-specific details can significantly impact the cost and retrofit scope required. For example, the standard combustion system for a GE F-Class gas turbine is only capable of approximately 5 percent hydrogen. Some combustion system upgrades may enable up to 18 to 20 percent, but a complete combustion system retrofit would be required to achieve higher

[51] 88 Fed. Reg. at 33,364.

[52] Technical Support Document (TSD) – Hydrogen in Combustion Turbine EGUs https://www.epa.gov/system/files/documents/2023-05/TSD%20-%20Hydrogen%20in%20Combustion%20Turbine%20EGUs.pdf.

[53] Technical Support Document (TSD) – Hydrogen in Combustion Turbine EGUs https://www.epa.gov/system/files/documents/2023-05/TSD%20-%20Hydrogen%20in%20Combustion%20Turbine%20EGUs.pdf.

blends, possibly up to 50 percent. Moreover, this combustion system retrofit option is not yet commercially available from the OEM for F-Class units. The latest GE DLN2.6e micromixer technology available for the more advanced 7HA.03 units would likely need further development to be applied for hydrogen blend capabilities on existing GE F-Class units. Turbines from other OEMs have similar constraints, although specific capability levels and details vary. While at very low hydrogen blends the impacts to a gas turbine and facility are minimal, the levels proposed by EPA could require large combustion system modifications, balance of plant retrofits, and additional operation and maintenance considerations. Some of the retrofits needed may include, but are not limited to, combustion system replacement, larger fuel supply piping diameter, hydrogen safety related modifications, control system modifications, and potential downstream control equipment (e.g., NO_x control) modifications.

Another important consideration for combusting hydrogen in combustion turbines is the potential additional NO_x emissions produced from the higher combustion temperatures that occur relative to natural gas. It is not clear that current NO_x reduction technologies, such as dry low NO_x or selective catalytic reduction (SCR), could be successfully operated to achieve NO_x emission rate requirements. This risk of high NO_x emission rates is of particular concern for existing combined cycle units that may not have the capability or on-site space to install more robust NO_x controls without significant and costly upgrades.

In addition, hydrogen must be delivered to the plant and stored in a safe manner. While hydrogen can be stored in certain types of geological formations, the current lack of hydrogen pipeline infrastructure requires these features to be located near the EGU, which is not always the case. Hydrogen can also be stored in pressure vessels, but this requires special materials to avoid embrittlement.

Safety issues also exist with regard to hydrogen combustion that would need to be resolved, specifically around flame stability. The turbine blade materials may also be more likely to become compromised under the higher flame temperature and embrittlement could become an issue.

While significant potential exists for hydrogen energy to facilitate transition of the economy to net-zero emissions, EPA's hydrogen pathways in this proposal rely on uncertain future buildout of hydrogen infrastructure along with aspirational supplies and prices for low-GHG hydrogen. The infrastructure required to accomplish the co-firing amounts described in the rule could take many years longer than EPA estimates. Furthermore, significant challenges remain with

hydrogen-fueled combustion turbines. Based on the factors described above, we recommend that the proposed hydrogen pathway compliance dates be extended by at least 5 years, with automatic extensions of those deadlines if adequate production and delivery infrastructure fails to materialize on the timelines EPA has anticipated.

E. The proposed compliance deadline for the CCS pathway for new and existing combustion turbines should be extended by at least five years.

As noted above, EPA is proposing a phased approach for applying performance standards to new base load combustion turbines. For the second phase, units may select a pathway that is based on the application of CCS with a 90 percent capture rate beginning January 1, 2035. EPA is also proposing emission guidelines that apply this CCS-based standard to existing large and frequently operated combustion turbines.

While there has been significant progress made in the development of carbon capture systems, the technology has never been installed on a commercial scale natural gas combined cycle or simple cycle combustion turbine generating unit. NGCC power plants inherently emit less CO_2 than other fossil fuel generation sources, such as coal or petroleum systems, so capture technologies for NGCC systems have not typically been used to generate a CO_2 stream for commercial purposes and, for years, research and development for CO_2 capture for GHG emission reductions was primarily focused on coal-fired EGUs.

More recently, DOE has funded, and is continuing to fund, multiple FEED studies for retrofitting carbon capture technologies to natural gas combined cycle facilities, but none of these projects have yet progressed to detailed design or deployment.

Southern Company has recently participated in two DOE-funded FEED studies for retrofitting CO_2 capture on a NGCC EGU, *excluding* the CO_2 transportation pipelines and storage facilities that would be required to permanently sequester the CO_2 underground. The first FEED study used Mississippi Power's Plant Daniel Unit 4 combined cycle facility as the host site to study a retrofit of Linde-BASF's post-combustion capture technology with a target of 90 percent CO_2 capture. The project team developed the retrofit design to a level of detail sufficient to support an Association for the Advancement of Cost Engineering (AACE) Class 3 cost estimate with an associated project schedule, including detailed design, procurement, construction, commissioning, and startup, estimated at roughly five years. The Plant Daniel FEED study took approximately 2

years to complete before concluding in 2022. The final project report is publicly available through the DOE's Office of Science and Technical Information (OSTI).[54]

The second FEED study project, which is ongoing, uses Alabama Power's Plant Barry Unit 6 combined cycle facility as the host site to apply a retrofit of Linde-BASF's post-combustion technology with a target of 95 percent CO_2 capture. This retrofit design includes more complex integration of the carbon capture system with the NGCC, including exhaust gas recirculation (EGR)., which recycles a portion of the exhaust gas from the heat recovery steam generator (HRSG) to the inlet of the combustion turbine, thus increasing the exhaust gas CO_2 concentration and decreasing the volume of gas to be treated in the CO_2 capture process. Both of these improvements should decrease the size of CO_2 capture equipment and improve efficiency of CO_2 capture. Similar to the Plant Daniel project, the project team is developing a cost estimate and schedule and will complete their work in December 2023.[55]

Participating in these FEED studies has provided Southern Company with significant insight into the technical and logistical aspects of integrating CO_2 capture on a NGCC. Upon completion of the Plant Barry study, Southern Company will be able to assess the impacts of site selection, capture system integration complexity, and increased carbon capture percentage, among other variables. Equally as important, these FEED studies have revealed and highlighted areas where more detailed work and experience is needed to understand operating, maintenance, and reliability impacts of NGCC with CCS on the electric grid. As recognized by Congress through the IIJA and subsequent DOE FOAs, the next step in application of CCS on fossil fuel-fired EGUs should include execution of demonstration projects to further define the operating flexibility and reliability of these critical units to enable comprehensive generation, transmission, and pipeline planning in support of broader CCS deployment. In addition, although DOE limited the scope of these FEED study projects to the carbon capture site and specifically excluded CO_2 transportation and storage, analysis by Southern Company indicates that pipeline siting, permitting, and construction will be a critical part of any comprehensive CCS project, likely extending the overall timeline for implementing CCS.

[54] https://www.osti.gov/servlets/purl/1890156/.

[55] https://netl.doe.gov/project-information?p=FE0032131.

There are important issues to consider with respect to retrofitting carbon capture technologies onto an existing NGCC unit. For example, carbon capture equipment requires roughly the same footprint as the existing combined cycle facility. Many facilities do not have sufficient space in proximity to the unit to accommodate the additional equipment and onsite space needs. Additionally, the lower CO_2 concentration found in flue gas from NGCC units, compared to coal-fired units, increases the amount and size of carbon capture equipment required for a given percentage of capture, leading to higher cost-per-ton values. Approaches to increase flue gas concentration, and thus decrease equipment sizes (such as EGR), require further design and testing to ensure reliable NGCC operation.

Combining a new NGCC with CCS is likely to require coordination between two different OEMs for major portions of the overall project scope since only one major turbine OEM currently has near-commercial carbon capture technology. Further development is needed to understand the best integration between NGCC equipment and carbon capture equipment. The steam cycle typically must be optimized for operation without carbon capture. Controls must be developed to synchronize operations of the generator and the capture equipment as much as possible. OEMs for both the NGCC and the carbon capture equipment naturally focus their designs to optimize the specific scopes of their own equipment. Since there are multiple, interconnected variables, optimizing the design of an integrated system requires both sides to collaborate iteratively to identify, understand, and then optimize the combined system rather than individual components. Balancing the energy inputs across both systems versus capital equipment sizing is critical. Further development is needed to understand the best integration between NGCC equipment and carbon capture equipment.

In addition, it has been noted that the amine-based solvent capture technologies used at Boundary Dam and Petra Nova merit further evaluation to identify and characterize any non-CO_2 emissions associated with applying amine-based capture to NGCC units. The DOE Office of Fossil Energy and Carbon Management will be requiring testing and analysis of these potential emissions with all technology development projects going forward.[56]

Due to prevailing operating and reliability risks and uncertainties for CCS on NGCC EGUs, along with the pipeline transportation and storage challenges enumerated in the discussion

[56] https://oced-exchange.energy.gov/FileContent.aspx?FileID=da7173f8-5127-466c-b9c5-2a57ee5c6713.

in Section III.B. of these comments, widespread utility-scale deployment of CCS technology for combustion turbines is years away, likely extending beyond the proposed 2035 compliance deadline.

The proposal preamble states,

> [t]he EPA believes that it is important to stagger CCS requirements for existing coal-fired units and new and existing fossil fuel-fired turbines to allow time for both deployment of CCS infrastructure and to accommodate increased demand for specialized engineering and construction labor needed to build CCS equipment. The EPA also believes that because coal-fired units emit more CO_2/MWh, that to the extent that there are limitations to the amount of CCS that can be installed by 2030 it makes sense to focus a CCS BSER on those coal-fired units first.[57]

Southern Company agrees that CCS projects should be focused on coal EGUs first, with the deadline for CCS on gas EGUs to be staggered behind coal EGUs in order to allow for efficient allocation of limited CCS-related resources. Accordingly, and based on the time needed to complete the above-mentioned DOE studies needed for demonstrations of CCS on NGCC units, EPA should extend the proposed compliance deadline for CCS on combustion turbines (i.e., NGCCs) by at least five years, with the compliance deadline for combustion turbines staggered to fall after the coal-fired EGU deadline. Therefore, we recommend EPA extend the proposed compliance deadline for new and existing combustion turbines by at least five years to December 31, 2039, or later, which will fall after the recommended December 31, 2035, proposed deadline for CCS on long-term existing coal units.

F. The proposed thresholds for new and reconstructed and "large and frequently operated" existing combustion turbine subcategories should be increased.

EPA should recognize the critical role of natural gas combined cycle generation to enable an orderly transition away from coal while maintaining affordability and reliability as significant amounts of non-dispatchable renewables are deployed. EPA's modeling of the proposal suggests that, in many cases, the most viable compliance approach will likely be to impose capacity factor limitations on affected units to avoid the risk and cost of the alternative compliance pathways for

[57] 88 Fed. Reg. at 33,361.

higher capacity factor units. For example, imposing a 50 percent capacity factor limit (based on design efficiency estimates cited by EPA in the proposal preamble) for "uncontrolled" new and reconstructed gas combined cycles will increase costs without providing the benefit of any significant emissions reductions as the curtailed generation is shifted to less efficient, higher cost and higher emissions rate units. In other words, less efficient units, with higher CO_2 emission rates, will be forced to increase operations and emissions while more efficient units, with lower CO_2 emission rates, will be forced to operate less. To minimize this outcome, EPA should increase the capacity factor limits for new and reconstructed combustion turbines. In particular, the capacity factor threshold for the intermediate load subcategory should be increased to at least 65 percent and the capacity factor threshold for the low load subcategory to at least 25 percent.

IV. EPA'S PROPOSED EMISSION GUIDELINES FOR EXISTING STATIONARY COMBUSTION TURBINES NEED SUBSTANTIAL CLARIFICATION AND REFINEMENT

EPA is proposing emission guidelines under CAA section 111(d) for a subset of existing combustion turbines that are "large and frequently operated." EPA is proposing a BSER for this subcategory of sources that is similar to the BSER for the new and reconstructed base load stationary combustion turbine subcategory and would require affected sources to achieve a degree of emission limitation that is consistent with the application of 90 percent CCS by 2035 or co-firing 30 percent low-GHG hydrogen by volume by 2032, increasing to 96 percent co-firing by 2038.

In the preamble to the proposed rule, EPA identifies two key factors it considered for establishing emission guidelines for combustion turbines: 1) the importance of addressing GHG emissions from this "growing portion of the inventory" sooner rather than later and 2) the size of the existing combustion turbine fleet and implications for feasibility and timing of implementing the BSER candidates (i.e., CCS and hydrogen co-firing). Based on these factors, EPA proposes to define "large and frequently operated" combustion turbines as "units greater than 300 MW with an annual capacity factor of greater than 50 percent. [58]

Contrary to EPA's assertion that the existing combustion turbine portion of the inventory is "growing," EPA notes that its own modeling shows that, in the baseline, combined cycle

[58] *Id.*

generation falls in each model year from 2028 through 2050, falling "by more than 50 percent between 2030 and 2045."[59] Furthermore, EPA's modeling of the proposed rule using the Integrated Planning Model (IPM) (which did not include modeling of the proposed emission guidelines for existing combustion turbines at the time of proposal publication) shows that, while there is a slight (2 percent) increase in generation from existing combustion turbines between 2028 and 2030, the year which the emission guidelines for coal-fired EGUs would go into effect, emissions from these units go down significantly (over 25 percent) by 2035.[60] This clearly contradicts EPA's assertion that "large and frequently operated" existing combustion turbines are a "growing portion of the inventory," even in the absence of emission guidelines for existing combustion turbines.

EPA states that, by focusing on "large and frequently operated" combustion turbines, this will have the effect of "limiting the amount of affected capacity to a degree that is consistent with the availability of" CCS and hydrogen co-firing.[61] EPA projects in the proposal that 37 GW of existing combined cycle capacity would meet the threshold criteria of greater than 300 MW capacity and capacity factor greater than 50 percent.[62] EPA explains that the ability to cost-effectively apply CCS was a significant consideration in their selection of the proposed capacity and utilization thresholds. EPA also considered and rejected capacity thresholds of 200 MW and 100 MW, finding that these thresholds would capture 85 GW and 134 GW of existing combustion turbine capacity, respectively.[63]

On July 7, 2023, EPA posted updated IPM modeling results to its GHG Standards and Emission Guidelines for Fossil Fuel Power Plants website that includes the proposed emission guidelines for stationary combustion turbines along with the proposed NSPS revisions and

[59] *Id*. at 33,362.

[60] See the "Proposal SSR.xlsx" spreadsheet summarizing IPM output for the proposal (https://www.epa.gov/system/files/other-files/2023-04/Proposal.zip).

[61] 88 Fed. Reg. at 33,361.

[62] 88 Fed. Reg. at 33,415. EPA's estimate that 37 GW of existing combined cycle capacity would be affected by the proposed emission guidelines is based on a "spreadsheet-based analysis" that EPA has included in the docket to this rulemaking. A review of this spreadsheet-based analysis indicates that EPA did not assess the capacity of actual units, instead basing their estimate on the IPM model's representation of these units.

[63] *Id*. at 33,367.

proposed emission guidelines for existing coal-fired EGUs.[64] This updated modeling that integrates the full extent of the proposal now shows 103 GW of stationary combustion turbine capacity affected, over two and a half times as much as EPA estimated in the proposal. An analysis by EPRI using EPA's eGRID database estimates that as much as 160 GW of combined cycle capacity could be affected.[65] Both of these sources of information suggest that EPA has substantially underestimated the number of units and total capacity that would potentially be subject to the proposal, thus substantially underestimating the potential cost and impacts of the proposal and raising serious concerns about the feasibility of applying the BSER candidates to this large portion of the combined cycle fleet within the 2035 time frame that EPA has proposed.

A. The proposed subcategory definition for "large and frequently operated" combustion turbines needs clarification.

EPA proposes to define "large and frequently operated" combustion turbines as "units greater than 300 MW with an annual capacity factor of greater than 50 percent."[66] Estimates of the amount of capacity that is potentially affected by the proposed emission guidelines and identification of specific units that would potentially exceed the 300 MW capacity threshold are challenging due to the lack of clarity in the proposal on the methodology for calculating the capacity of a combined cycle combustion turbine.[67] Neither the preamble to the rule nor the draft regulatory text for the proposed existing source emission guidelines provide details on how to make this determination. According to the proposed text of § 60.5850b(a), EGUs EPA would exclude from being affected by the proposal include:

> Natural gas fired stationary combustion turbines with an electric generating capacity equal to or less than 300 MW or with an electric generating capacity of more than 300 MW and that operate at an annual capacity factor equal to or less than 50 percent. [68]

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[64] https://www.epa.gov/stationary-sources-air-pollution/greenhouse-gas-standards-and-guidelines-fossil-fuel-fired-power.

[65] See EPRI comments to Docket EPA-HQ-OAR-2023-0072 at 11.

[66] 88 Fed. Reg. at 33,361.

[67] There are no simple cycle combustion turbines owned and operated by Southern Company that approach the 300 MW capacity threshold.

[68] Regulatory Text – Proposed Emission Guidelines at 12 (emphasis added).

Thus, the emission guidelines are potentially applicable to units that have an electric generating capacity greater than 300 MW. However, the term "electric generating capacity," is not defined in the preamble or in the regulatory text. In response to questions EPA had received seeking clarification of the applicability requirements of the proposed emission guidelines, EPA sent a memo to the docket on June 12, 2023, attempting to clarify the definition.[69] The memo, however, does not provide the clarity that is needed.

In its memo, EPA points to other definitions in the rule that purport to shed light on the meaning of electric generating capacity. EPA clarifies in the memo that the capacity of a combustion turbine that is part of a combined cycle generating unit includes a prorated or apportioned amount of any associated steam turbines, including heat input from duct burners. However, the text and terms that are referenced (e.g., base load rating, physical design, ISO conditions) largely pertain to fuel consumption and efficiency and do not clearly explain how to determine the electric generating capacity of the unit. Furthermore, the reference in the memo to actual generation measurements as a method for apportionment and determination of the electric generating capacity of the unit suggests that the 300 MW threshold should have some basis in actual performance versus engineering design.

The potential impact of the proposed definition of electric generating capacity could be profound for Southern Company and could affect nearly all of the combined cycle units in the Southern Company system, which total over 13,000 MW of capacity.

B. Southern Company agrees with the proposal that EGUs regulated as new sources are to be excluded from existing source regulations, which is clearly supported by the CAA.

In the preamble to the proposal, EPA explains that the emission guidelines would not apply to units that are currently subject to the requirements of the 2015 new source performance standards:[70]

[69] Applicability of Emission Guidelines to Existing Stationary Combustion Turbines: FAQs Memo to the Docket (June 12, 2023).

[70] The 2015 NSPS, codified under 40 CFR part 60 subpart TTTT, establishes emission standards and compliance schedules for the control of GHG emissions from a steam generating unit, IGCC, or a stationary combustion turbine that commences construction after January 8, 2014, or commences modification or reconstruction after June 18, 2014.

> Section 111(a)(6) of the CAA defines an ''existing source'' as ''any stationary source other than a new source.'' Therefore, the emission guidelines would not apply to any EGUs that are new after January 8, 2014, or reconstructed after June 18, 2014, the applicability dates of 40 CFR part 60, subpart TTTT.[71]

The proposed regulatory text further confirms that sources subject to the 2015 NSPS are not subject to the proposed emission guidelines. Proposed § 60.5850b(b) states that EGUs that are excluded from being affected EGUs include:

> New or reconstructed EGUs that are subject to 40 CFR part 60 subpart TTTT of this part as a result of commencing construction after the subpart TTTT applicability date.[72]

We agree with EPA's position in the proposal that the CAA makes clear that a source cannot be both existing and new. The definitions of new source and existing source in Section 111 of the CAA are clearly meant to be mutually exclusive, with "existing source" defined as anything "other than a new source."[73]

However, in EPA's June 12, 2023, memo to the docket on the Applicability of Emission Guidelines to Existing Stationary Combustion Turbines: FAQs, EPA directly contradicts the proposed language in the preamble and the proposed regulatory text. EPA argues that the term "EGUs" in proposed § 60.5850b(b) only refers to steam generating units, not stationary combustion turbines. This interpretation of the term EGUs directly contradicts § 60.5700b, the opening section of the proposed UUUUb emission guidelines, which states, "An affected steam generating unit or natural gas fired stationary combustion turbine shall, for the purposes of this subpart, be referred to as an affected EGU."[74] Furthermore, this interpretation implies that CAA section 111(a)(6) applies differently to steam generating units than to stationary combustion turbines, which is not supported by the language of this section of the CAA.

EPA's revised interpretation in the FAQ memo of the applicability of the emission guidelines to units currently subject to requirements under TTTT directly contradicts the proposal preamble and regulatory text and would regulate GHG emissions from any unit that began

[71] 88 Fed. Reg. at 33,342.

[72] Regulatory Text – Proposed Emission Guidelines at 12.

[73] 42 U.S.C. § 7411(a)

[74] Regulatory Text – Proposed Emission Guidelines at 1.

construction after January 8, 2014, but prior to May 23, 2023, as both a new source under the current TTTT and as an existing source under UUUUb.[75] Thus, the approach recommended in the FAQ memo is inconsistent with the plain language of section 111 of the CAA.

Importantly, even in circumstances where EPA might be permitted to reverse its stated position on the interpretation of the CAA, EPA must first propose its reversed position for public notice and comment and could not make that reversal based on a memo released by the Agency during the public comment period. Here, in light of the language of section 111, EPA should affirm that, consistent with the CAA, the proposed regulatory text, and the preamble language, *all* EGUs—both steam generating and combustion turbine—that are subject to TTTT under the 2015 NSPS are excluded from the proposed emission guidelines.

V. EPA SHOULD CONSIDER TRANSMISSION AND GRID RELIABILITY IMPACTS FROM THE PROPOSAL IN ADDITION TO RESOURCE ADEQUACY.

As coal-fired EGUs continue to retire over the coming years, combustion turbines (including both combined cycle and simple cycle units) will be critical to keeping the grid reliable and resilient, providing firm, dispatchable generation as more variable and non-dispatchable renewable resources continue to come online. As deep decarbonization of the power sector and the broader economy occurs, combined cycle units can provide flexible operations, including intermediate to base load electricity, and quick-start simple cycle combustion turbines can serve as reserve backup for variable renewable generation, which is key to maintaining reliable, resilient, and affordable energy. It is important for EPA to keep top of mind the valuable reliability role that combustion turbines will play as it considers regulation of CO_2 emissions from those units in the future. To that end, it is important for EPA to ensure that new combustion turbines can be constructed to ensure that the electric needs of the U.S. continue to be met in a reliable and affordable manner during the energy transition.

NERC defines "reliable operation" of the electric bulk power system to mean "operating the elements of the bulk power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures…will not

[75] Plant Barry Unit 8 is a natural gas combined cycle unit that began construction in March 2021 and is scheduled to enter commercial operation on or before November 1, 2023. This unit is subject to the NSPS requirements under 40 CFR Part 63 Subpart TTTT.

occur…."[76] EPA's Resource Adequacy Analysis TSD defines "resource adequacy" as the "provision of adequate generating resources to meet projected load and generating reserve requirements in each power region,"[77] stating further that resource adequacy is "a key planning metric that is necessary (*but not sufficient*) for grid reliability."[78] Reliability refers to the ability of the bulk power system to continuously deliver energy to meet load requirements for all power system users across all hours such that no electric system load experiences an involuntary outage of service.

As stated in NERC's March 2023 white paper, in addition to resource adequacy assessments, "energy reliability assessments are critical for assuring the reliable operation of the Bulk Power System…. The variability of renewable generation, demand volatility, the need for sufficient flexibility from balancing generation resources, and the potential for natural gas supply interruptions all combine to highlight the need for energy reliability assessments that analyze all hours of a given study period rather than just the peak hours" typically addressed in resource adequacy assessments.[79]

Energy reliability assessments seek to address concerns over generating resources' ability to supply energy and ancillary services to the electric grid to reliably meet load requirements. NERC states that reliability assessments

> should include the following:
>
> - Consideration of impacts associated with limited resource availability, including constraints imposed by the unassured and limited supply of fuel and other consumable resources (e.g., cooling water) that may be depleted or unavailable and required for the reliable operation of a power plant, especially resources depleted by multiple generators simultaneously.

[76] Glossary of Terms Used in NERC Reliability Standards, https://www.nerc.com/pa/Stand/Glossary of Terms/Glossary_of_Terms.pdf (updated March 8, 2023).

[77] Resource Adequacy Analysis TSD https://www.epa.gov/system/files/documents/2023-05/Resource Adequacy Analysis TSD.pdf.

[78] *Id.* at 3 (emphasis added).

[79] Considerations for Performing and Energy Reliability Assessment, ERATF White Paper (March 2023), at p. iv, https://www.nerc.com/comm/RSTC_Reliability_Guidelines/ERATF_Whitepaper_24Feb2023_clean%20(003).pdf.

> - Consideration of the combined limitations (including emissions limitations) applicable to all resources and transmission.
>
> - Calculation of the potential impact of resource depletion, including energy storage and hydro resources.
>
> Energy reliability assessments are different from capacity assessments in that they examine a span of time over all hours rather than a single, independent point in time.[80]

Additionally, NERC describes in detail the value of applying probabilistic methods in both energy and capacity assessments. Deterministic methods, as used by EPA in the resource adequacy assessment, provide a single outcome for each modeled scenario that is uniquely coupled with the fixed input assumptions. This approach does not provide assurance that the expected level of reliability, as expressed in metrics such as loss of load expectation (LOLE), will be maintained through significant fleet transition. NERC recommends applying distributions of uncertainty to each element of the assessment, including representation of demand, supply, and transmission of electricity.

In contrast to NERC's recommendations, EPA suggests that reliability concerns have been adequately evaluated through a deterministic analysis focused solely on resource adequacy, which represents only one component of overall grid reliability. Given the extremely short comment period for such a complex and impactful proposal, it is simply not possible for affected entities to fully assess the potential generation and transmission planning and electric service reliability impacts of the proposal. EPA should engage with federal and regional reliability authorities to fully consider and seek to mitigate adverse impacts of this proposed rule on overall grid reliability, including the energy reliability components cited in NERC's white paper.

As discussed earlier, the retirement of large central station generating units, such as Plants Bowen and Miller, will trigger the need for significant updates to the transmission and electric generation infrastructure, including construction and commissioning of new generating units, all of which must be conducted in a carefully coordinated manner to maintain reliability and affordability for customers. The proposed rules further intensify reliability planning concerns because the required state plans affect not only large coal units, such as Plants Bowen and Miller,

[80] *Id*. at p.1 (emphasis added).

but also other remaining large dispatchable fossil generating assets across the Southern Company system, many of which similarly serve critical grid reliability roles. At the same time, EPA's proposal also affects new power plants that will be needed to both replace retiring generation and meet the increasing needs of growing populations and economies. Placing arbitrary, one-size-fits-all capacity factor constraints on fossil units across Southern Company's fleet would diminish the flexibility of our fleet to operate in a way that maintains reliability while optimizing cost.

To support the continued growth of renewables and a reliable electric grid, EPA must consider, as part of its proposed section 111 rules for the power sector, the importance of responsibly transitioning the fleet and the continued need for large, flexible, cost-effective, dispatchable, and efficient generating assets, such as existing and new natural gas-fired combined cycle facilities. Extending the proposed rules' timelines is necessary to provide adequate time to transition the fleet at a pace that supports continued reliable and affordable electric service, including time to evaluate and address transmission impacts that will continue to evolve from the continued growth of renewables, storage, and other electric system infrastructure. EPA should also provide clear support in the proposed rules for the broad authority that states have and the flexibilities allowed in state plans to ensure customers do not suffer unanticipated adverse consequences during the ongoing fleet transition.

VI. CONCLUSION

Southern Company appreciates EPA's effort in developing this proposal, and we remain committed to our goal of achieving net-zero GHG emissions by 2050 by efficiently transitioning our generation fleet in a manner which prioritizes reliability and affordability for the customers and communities we are privileged to serve. The orderly transition of our fleet will require the addition of significant amounts of generating resources, along with the associated expansion and adjustments to transmission and pipeline infrastructure, as existing fossil generating units retire. We urge EPA to provide the recommended added flexibility and adequate time frames necessary to support the permitting, technology development and demonstration, construction, and regulatory approval processes required to accommodate an orderly fleet transition. Southern Company supports regulatory action that achieves GHG emissions reductions from the electric sector while recognizing the importance of maintaining clean, safe, reliable, and affordable energy.

Southern Company appreciates the opportunity to provide constructive input for this important rulemaking. We look forward to additional opportunities for engagement to support development of a durable, effective rule designed to facilitate continued progress toward an orderly and cost-effective transition of the electric sector. We commit to collaboration on this rulemaking, and we look forward to continuing our engagement with the Agency on this topic. We confirm that Southern Company will engage constructively with EPA to support carbon standards for not only existing coal but also for new and existing gas plants in their final form.

Cautionary Note Regarding Forward-Looking Statements

Certain information contained in this document is forward-looking information based on current expectations and plans that involve risks and uncertainties. Forward-looking information includes, among other things, statements concerning GHG reduction goals, including timing of achievement, expected unit retirements, and expected renewable and carbon free generation growth. Southern Company 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 Southern Company; accordingly, there can be no assurance that such suggested results will be realized. The following factors, in addition to those discussed in Southern Company's Annual Report on Form 10-K for the year ended December 31, 2022 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, as well as changes in application of existing laws and regulations; current and future litigation or regulatory investigations, proceedings, or inquiries; variations in demand for electricity and natural gas; available sources and costs of natural gas and other fuels and commodities; the ability to control costs and avoid cost and schedule overruns during the development, construction and operation of facilities or other projects; the ability to construct facilities in accordance with the requirements of permits and licenses, 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, including the pace and extent of development of low- to no-carbon energy and battery energy storage technologies and negative carbon concepts; performance of counterparties under ongoing renewable energy partnerships and development agreements; state and federal rate regulations and the impact of pending and future rate cases and negotiations; the ability to successfully operate the electric utilities' generation, transmission and distribution facilities, Southern Power’s generation facilities and Southern Company Gas' natural gas distribution and storage facilities and the successful performance of necessary corporate functions; and the performance of projects undertaken by the non-utility businesses and the success of efforts to invest in and develop new opportunities. Southern Company expressly disclaims any obligation to update any forward-looking information.