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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; Supplemental Notice of Proposed Rulemaking; 88 Fed. Reg. 80,682 (November 20, 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) November 20, 2023, Federal Register notice seeking additional public input on mechanisms and tools to address reliability concerns related to the proposed standards of performance for new, modified, and reconstructed fossil fuel-fired electric generating units (EGUs) and emission guidelines for existing EGUs. We appreciate EPA's recognition of the critical importance of providing flexibilities in a final rule to mitigate reliability challenges associated with the proposal. On behalf of The Southern Company and its subsidiaries, Alabama Power Company, Georgia Power Company, Mississippi Power Company, and Southern Power Company, we respectfully submit these comments for your consideration.

We are at a critical juncture in our country's energy transformation, which is happening simultaneously alongside historical increases in load growth. Both realities are accelerating due to a combination of state energy policy and economic development efforts along with the significant opportunities afforded under the Inflation Reduction Act (IRA) and other clean energy legislation that have sparked economic investments in clean energy technologies in our service territory and across the country. As regulated utilities, industry, state regulators, federal regulatory agencies, and other stakeholders adapt to this rapidly changing landscape, we must remain steadfast in our commitment to ensure the lights remain on and energy remains affordable, all while moving toward our shared goals of a decarbonized future.

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

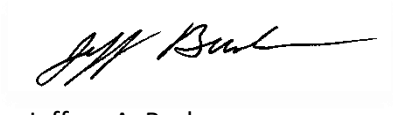
decarbonizing at a pace that is supported by technology and infrastructure advancement to enable an orderly energy transition. Serving as the Balancing Authority and Reliability Coordinator for a multi-state region, Southern Company is particularly qualified to provide constructive input to EPA on the issue of reliability of the electric grid.

The Southern Company is committed to net-zero GHG emissions by 2050 and has made excellent progress toward our GHG emission reduction goals. As we continue our transition to net-zero GHG emissions, we remain focused on maintaining a resilient system that provides reliable 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 recommendations in our comments to address the reliability concerns raised by the proposal include:

- Extend compliance deadlines and increase subcategory capacity factor thresholds.
- Make clear that reliability is an important "RULOF" factor and states are particularly suited to assess and account for it.
- Allow flexible mass-based averaging and trading across all affected units.
- Clarify and revise the proposed "system emergency" provision.

The Southern Company commits to collaboration on this rulemaking, and we look forward to continuing our engagement with the Agency on this topic. 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

Supplemental Notice of Proposed Rulemaking

88 Fed. Reg. 80,682 (Nov. 20, 2023)

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I. Introduction

On November 20, 2023, EPA published a Supplemental Notice of Proposed Rulemaking 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 (SNPR). Among other things, the SNPR seeks input on "whether to include mechanisms to address potential reliability issues" identified by multiple parties, including Southern Company,[1] during the initial comment period for this proposal. We appreciate EPA's recognition in the SNPR of the vital importance of providing flexibilities in a final rule to mitigate reliability concerns associated with the proposal.

We are at a critical juncture for the energy transformation in this country, which is happening *simultaneously* alongside historical increases in load growth. Both realities are accelerating due to a combination of state energy policy and economic development efforts along with the significant opportunities afforded under the Inflation Reduction Act (IRA) and other clean energy legislation that have sparked economic investments in clean energy technologies in our service territory and across the country. For example, Southern Company's largest subsidiary, Georgia Power Company, recently announced a *seventeen-fold* increase in projected load growth over the next seven years compared to the projections made just over a year ago.

[1] Southern Company is a leading energy company serving nine million customers through its subsidiaries. We are committed to greenhouse gas (GHG) emissions reductions and have a goal of net zero GHG emissions by 2050 that is designed to recognize the importance of decarbonizing at a pace that is supported by technology and infrastructure advancement. Maintaining affordable and reliable electric service for our communities is critical to supporting economic growth as the power sector and the rest of the economy transition to net zero GHG emissions. As Southern Company works to achieve a net zero future, we remain committed to our core principles of providing clean, safe, reliable, and affordable energy to our customers and communities, while conserving and protecting the environment for future generations. 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, GHG emissions, and customers, refer to those operations conducted through its subsidiaries.

As regulated utilities, industry, state regulators, federal regulatory agencies, and other stakeholders adapt to this rapidly changing landscape, we must not lose sight of our North Star: to ensure that the lights are on and energy is affordable, all while moving toward our shared goals of a decarbonized future.

As recognized by the North American Electric Reliability Corporation (NERC)[2] in their December 2023 Long Term Reliability Assessment, "[r]egulations that have the potential to accelerate generator retirements or restrict operations must have sufficient flexibility and provisions to support grid reliability."[3] Given the undisputed importance of electricity as a necessity, reliability of the electric grid is paramount. Because of our obligation and unwavering commitment to reliably and affordably serve our customers, we submit these comments to emphasize the points made in our prior comments submitted to this docket on August 8, 2023:[4] chief among them that the timelines in the proposed rules, some of which are infeasible, could lead to an inefficient fleet transition pathway that adds unnecessary costs and reliability risk for customers. As the transition toward a low-carbon economy continues to evolve, and the growth of the clean energy sector continues to progress, reliability of the electric grid remains vital for the customers that we serve. We urge EPA to provide additional time and flexibilities in the final 111 rule to mitigate reliability concerns associated with the proposal. Without additional time and flexibilities to build and

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[2] *See* North American Reliability Corporation, https://www.nerc.com/AboutNERC (last visited Dec. 19, 2023)("The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the bulk power system through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the Electric Reliability Organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the bulk power system, which serves nearly 400 million people.").

[3] North American Electric Reliability Corporation, *2023 Long-Term Reliability Assessment*, (Dec. 13, 2023), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf.

[4] https://www.regulations.gov/comment/EPA-HQ-OAR-2023-0072-0642

operate the generation and transmission infrastructure necessary to accommodate the ongoing energy transformation and simultaneous load growth, we expect our customers would face serious reliability risks and added cost as this rule is implemented.

As explained in more detail in Section II of these comments, Southern Company is particularly qualified to provide input to EPA on the issue of reliability of the electric grid. In addition to owning and operating a diverse fleet of generating resources, Southern Company serves as the Balancing Authority and Reliability Coordinator[5] for its own system as well as those of certain of its neighbors, with similar responsibilities for the reliability of the electric grid as Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs). Serving as a public utility and as a Balancing Authority and Reliability Coordinator requires Southern Company to work closely with our state and federal regulators (including FERC, NERC/SERC, and state public service commissions) to help ensure there is adequate generation, transmission, and distribution available to reliably serve our customers. Reliability, environmental requirements, costs, etc. are all considered together as we develop plans to continue to serve our customers now and well into the future.

It is important for EPA to use its authority under section 111 of the Clean Air Act (CAA) to address reliability and affordability concerns and to recognize and support the broad authority provided to states to address these concerns under section 111(d). Section IV of these comments provides recommendations for reliability tools and mechanisms EPA should include in a final rule to help ensure the reliability of the electric grid as the 111 regulations are implemented. While there is not

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[5] NERC defines a Balancing Authority as the responsible entity that integrates resource plans ahead of time, maintains load interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time. A Reliability Coordinator is the entity that is the highest level of authority who is responsible for the Reliable Operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. An RTO may register with NERC to be a Reliability Coordinator and Balancing Authority. (*See* North American Electric Reliability Corporation, *Reliability Functional Model Technical Document – Version 5.1* (Dec. 12, 2018), https://www.nerc.com/pa/Stand/Functional%20Model%20Advisory%20Group%20DL/FM_Technical_Document_V5-1_clean_10082019.pdf).

a single silver bullet to address the reliability risks posed by the proposed rule, it is critically important that EPA make clear that reliability and affordability are fundamental factors when considering facility-specific standards and timelines that are based on "remaining useful life and other factors" (RULOF). In addition, EPA should support other important reliability mechanisms, such as trading/averaging programs and provisions to address system emergencies. We remain committed to constructive engagement with EPA on this rulemaking to help ensure clean, safe, reliable, and affordable energy for the customers and communities we are privileged to serve through the ongoing energy transition.

A. Southern Company and the Electric Utility Industry Are Leading the Transition to a Low Carbon Future.

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 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."[6] EPA data show that, 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.[7]

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 substantial progress toward these goals while, at the same time, 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

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[6] https://www.eei.org/resources-and-media/energy-talk/Articles/2023-04-Americas-Electric-Companies-Are-Leading-on-Clean-Energy.

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

capacity. We have reduced the number of coal-fired generating units in our fleet from 66 in 2007 to 15 in 2022, and we expect further reductions through the mid-2030s, subject to regulatory approval. 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.

The electric utility industry and the Southeast region we serve are at a critical juncture in the clean energy transition, and we must maintain an unwavering, fundamental focus on ensuring 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 rule provides inadequate lead time to install assets necessary for compliance and would impose severe limitations on resources that are needed to support our ongoing fleet transition and the reliability of service to customers. For vertically-integrated, state regulated utilities with accelerating load growth, we believe EPA has greatly 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 GHG 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.

B. The Southeast Region is Experiencing Historic Load Growth.

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 fleet transition activities to help ensure a continued supply of clean, safe, reliable, and affordable electricity. As stated in Georgia Power's 2023 IRP Update, which was filed in October 2023 at the Georgia Public Service Commission, along with requests for approval for additional generation

and demand-side resources, current demand projections far exceed the demand projected in the 2022 IRP. Based on the information and economic activity at the time of the 2022 IRP, Georgia Power anticipated less than 400 MW of growth between the winter of 2023/2024 and the winter of 2030/2031. In contrast, current projections reflect load growth of 6,600 MW through the winter of 2030/2031, which is approximately seventeen times greater than previously forecasted.

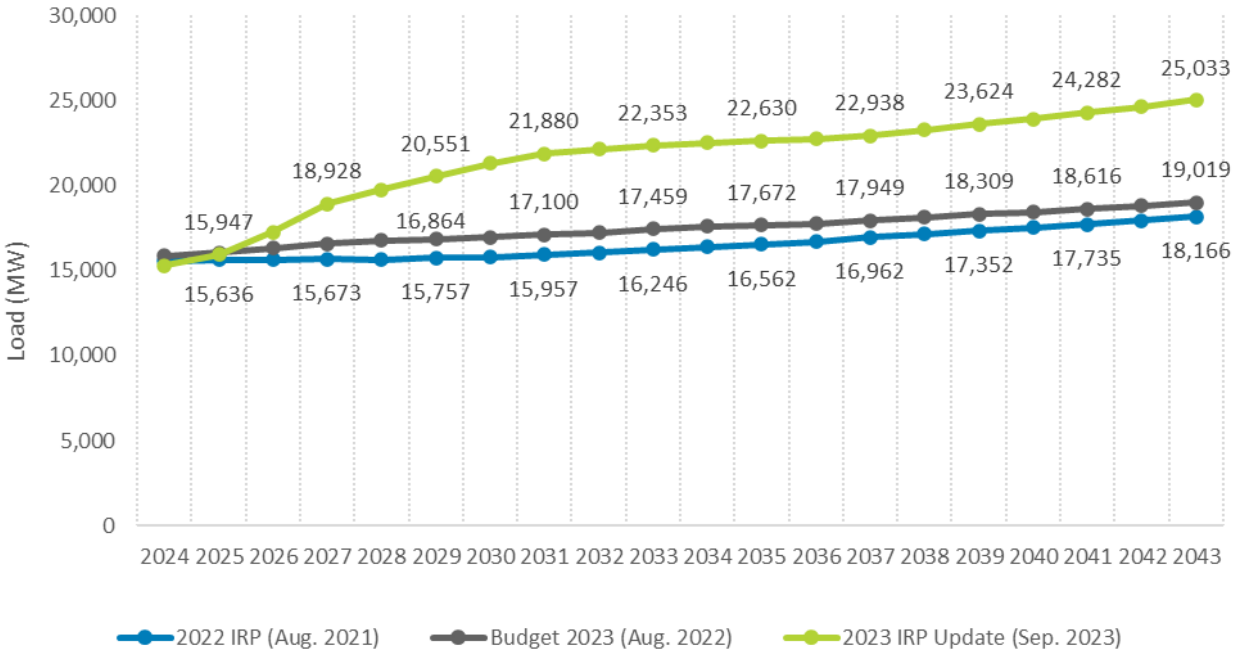


Figure 1. Georgia Power projected winter peak demand for the 20-year period spanning the winter of 2023/2024 through the winter of 2042/2043.

The surge of economic development projects in Georgia corresponds to an influx of new business lines, including solar panel manufacturing, electric vehicle manufacturing industry, and hyper-scale data centers. Not only does the scale of planned individual projects in Georgia fall outside of historical norms, with some individual projects surpassing 1,000 MW of load demand, 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 GHG emissions across the economy. Rapidly constraining dispatchable resources, such as the remaining

coal units and efficient natural gas combined cycles (NGCC), could hurt the long-term clean energy 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 framework is critical to ensure the timely development of generation, transmission, and demand-side resources necessary to provide reliable and affordable electricity to the Southeast region during its accelerated economic expansion.

C. Reliability of the Electric Grid is Paramount and Must be a Priority Through the Energy 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.

Southern Company urges 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 (i.e., those options for which energy output can be directly controlled at all times to meet real-time load demand, such as nuclear and fossil-fueled generation) increases, as these resources

are needed to maintain grid reliability while serving increasing load demand.[8] 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, we urge EPA to fully consider these important factors as the Agency finalizes section 111 GHG rules for the power sector.

II. Southern Company's Vertically Integrated Structure Facilitates Reliable, Integrated Operations and Robust Long-Term Planning.

Due to Southern Company's vertically integrated structure and role as the Balancing Authority and Reliability Coordinator for its region, the Company is well positioned to assess the proposal's potential impacts on reliability.

Southern Company's retail electric operating companies[9] are wholly owned, vertically integrated utilities that own generation, transmission, and distribution facilities. Since the late 1940s, they have operated as an integrated electric utility system and have conducted their respective electric generating facilities and system operations together in a coordinated, synergistic manner. Agreements in effect with principal neighboring utility systems provide for capacity and energy transactions that may be entered into for reasons related to reliability or economics.

In the Southeast, the SERC Reliability Corporation (SERC) was formed as a regional entity to which reliability enforcement and other authorities are delegated from FERC and NERC, with

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[8] North American Electric Reliability Corporation, *2023 Long-Term Reliability Assessment,* p.14 (Dec. 13, 2023), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf.

[9] Southern Company's retail electric operating companies include Alabama Power Company, Georgia Power Company, and Mississippi Power Company.

authority over our retail electric operating companies, along with other utilities in the Southeast. In addition to its responsibilities over audit and enforcement of NERC standards, SERC also coordinates voluntary industry reliability activities among the utilities in the Southeast aimed towards improving the reliability and adequacy of electric generation and transmission in the area.

A. Southern Company's Retail Electric Operating Companies Utilize Long-Term, Proactive Planning.

Electric utility customers expect and depend on high levels of service reliability. As such, a utility must have an economically balanced level of generating capacity that both exceeds the peak load and maintains an appropriate degree of reserve capacity to meet an established minimum reliability threshold. To have this reserve capacity available when it is needed, a utility must plan beyond the upcoming season because the processes to secure capacity, such as building a new unit or procuring a power purchase agreement (PPA), typically take a number of years to complete when considering state-required competitive procurement and regulatory approval processes. Southern Company regularly conducts a reliability study to determine the amount of reserve capacity – or the target reserve margin ("TRM") – that should be maintained on the Southern Company system to meet the minimum reliability threshold. The TRM is used to help establish the long-term capacity and energy needs and is re-evaluated on a periodic basis.

Reserve margins are necessary because of uncertainties in operational conditions. The four primary uncertainties influencing the TRM are: weather; load forecast; unit outage performance; and the cost to add generation resources. Regulations, such as the 111 proposal, could result in early retirement or capacity limitations for some generating units. While each of these individual factors creates a need for capacity reserves on its own, confluence of all these risk factors poses considerable risk to reliability.

Southern Company's retail electric operating companies utilize long-term, proactive planning, which is driven primarily by state-regulated processes to identify resources to meet load obligations and capacity reserves consistent with the TRM. These plans are reviewed and considered by state commissions and, separately, additions of new generation must be preceded by approval by those commissions. These processes result in generation procurement (through construction, acquisition, and/or power purchase agreements) that meets projected needs and

avoids over-reliance on third party electricity marketers that do not have an obligation to serve load.

These state-regulated planning processes also provide an efficient mechanism to incorporate future generation interconnections and integration, leading to the corresponding transmission projects that are necessary to implement these plans. Accordingly, vertically integrated, IRP-driven transmission owners, including Southern Company, are advancing the integration of renewables and other low- and no-carbon technologies through holistic, integrated, and proactive planning to continue to deliver reliable and resilient electricity service to the customers and communities we serve.

B. Southern Company Conducts Season-Ahead Analyses to Identify and Mitigate Reliability Challenges.

Prior to each peak season (i.e., summer and winter), Southern Company's Fleet Operations team performs a seasonal readiness analysis to identify potential reliability risks. The analysis is a comparison of the resource capacity that is expected to be available in the peak load hour for the season compared to the total retail and wholesale electricity obligations. Sensitivities are performed at varying unplanned generating unit outage rates and ambient temperature/load points to identify the combinations of temperature and unit performance at which non-firm and firm load would be at risk. By performing the analysis in the months prior to the peak season, mitigation efforts, such as improving fuel inventory, making reliability purchases (if available), or rescheduling planned outages, can be considered if the risks are deemed to be outside of acceptable tolerances. In recent years, as increasing amounts of dispatchable generating units across the region have retired, the amount of firm capacity available for purchase from the market has been decreasing, reducing the options for season-ahead risk mitigation. These options will be further constrained by regulations, such as the proposed rule, that would result in accelerated retirement of large dispatchable generating resources.

C. Southern Company's Role as a Balancing Authority and Reliability Coordinator

Southern Company serves as the NERC registered Balancing Authority (BA) for an area that spans three states in the southeastern portion of the U.S. The Southern BA (SBA) is responsible for maintaining reliable operating conditions within the SBA Area (SBAA) but is also obligated to

assist in maintaining the overall reliability of the Eastern Interconnection (EI), which represents over 70 percent of the energy utilized in North America. The BA entities across the EI are responsible for ensuring the proper management of energy transactions within the interconnected/adjacent BA entities and to maintain the 60 Hz frequency stability of the EI. If the supply of electricity falls below demand, it can cause the system frequency to drop below stable levels, risking significant permanent physical damage to electrical equipment and prolonged grid-wide blackouts. In an attempt to avoid such situations, BA entities may direct utilities to shed electrical load to bring supply and demand into balance.

The SBAA is fully contained within the Southeastern Reliability Coordinator (RC) footprint. From a near real-time (rolling 10-day window) to real-time basis, evaluations are performed to ensure resources are committed and dispatched on an optimal production cost basis while considering known constraints, limitations, and reliability requirements assigned by the transmission operator (TOP), BA, and RC. All known risks are considered, including, but not limited to, weather, actual/expected unit availability, fuel availability, transmission constraints, operational constraints, etc.

Southern Company, which serves as the RC for an area that covers parts of Alabama, Georgia, and Mississippi, has the highest level of authority responsible for the reliable operation of the electric power system in this region; it has a wide-area view, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. If an emergency occurs, the RC plays a lead coordination role across the interconnection in order to resolve the emergency. The RC monitors the interconnected transmission system across multiple local TOPs. The RC is best positioned to address an adverse condition on the bulk power system and has authority under NERC's Interconnection Reliability Operations and Coordination (IRO) Reliability Standards to act or direct others to act (e.g., by issuing operating instructions to transmission operators) to maintain system reliability and to prevent or mitigate emergency operating situations.

III. EPA's Proposed 111 Rules Raise Significant Reliability Concerns.

A. The Electric Grid is Facing Reliability Risks

In its December 2023 Long-Term Reliability Assessment (2023 LTRA), NERC states that "[t]he North American [Bulk Power System] is on the cusp of large-scale growth, bringing reliability challenges and opportunities to a grid that was already amid unprecedented change."[10] A recent report from the consulting firm, Grid Strategies, finds that "[g]rid planners forecast peak demand growth of 38 gigawatts (GW) through 2028" and that "[t]his is likely an underestimate."[11] The report attributes much of this demand growth to investments in manufacturing facilities, spurred by the Inflation Reduction Act, and data centers, driven by new generative artificial intelligence.

NERC's 2023 LTRA goes on to state:

> *This assessment provides clear evidence of growing resource adequacy concerns over the next 10 years. Capacity deficits are projected in areas where future generator retirements are expected before enough replacement resources are in service to meet rising demand forecasts. Energy risks are projected in areas where the future resource mix could fail to deliver the necessary supply of electricity under energy-constrained conditions.*[12]

This report raises alarming concerns about the reliability of the electric grid, particularly due to risks from additional environmental regulatory pressure. According to NERC,

> *Environmental regulations and energy policies that are overly rigid and lack provisions for electric grid reliability have the potential to influence generators to seek deactivation despite a projected resource adequacy or operating reliability risk; this can potentially jeopardize[e] the orderly transition of the resource mix. For this reason, regulators and policymakers need to consider*

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[10] North American Electric Reliability Corporation, *2023 Long-Term Reliability Assessment*, p.6 (Dec. 13, 2023), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf.

[11] https://gridstrategiesllc.com/wp-content/uploads/2023/12/National-Load-Growth-Report-2023.pdf.

[12] North American Electric Reliability Corporation, *2023 Long-Term Reliability Assessment*, p.6 (Dec. 13, 2023), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf.

> *effects on the electric grid in their rules and policies and design provisions that safeguard grid reliability.*[13]

EPA should continue to engage with federal and regional reliability authorities to fully consider and seek to mitigate adverse impacts of this proposed rulemaking on overall grid reliability, including the energy reliability components cited in NERC's white paper.

B. The Proposed 111 Rules Create Additional Reliability Risk

While population and economic growth in the Southeast region of the United States are expected to outpace the nation through the 2030s, our service territory is growing much faster than the Southeast region as a whole. During this critical period, the proposed rules would place widespread additional constraints on the electric grid, which agencies, such as NERC, have cautioned will already face challenges across the nation, even absent the additional pressures from this proposal.[14] EPA's regulatory impact analysis for the proposed rules likely substantially underestimates the risks, time requirements, and cost of the proposal, and this misalignment of EPA's estimates versus reality can adversely impact grid reliability as the rule is implemented.

Transmission, pipelines, and other critical elements and infrastructure affecting project schedules are not adequately accounted for, and projections of lead-time, 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 (H2), are unrealistic.

The technologies that EPA has proposed as "best system of emissions reduction" (BSER) (i.e., natural gas co-firing, hydrogen co-firing, and CCS) will require rapid buildout of significant amounts of pipelines and other critical infrastructure, a large portion of which is beyond the control of the owners of electric generating units (e.g., CO_2, natural gas, and hydrogen pipelines), and at a pace that is infeasible. For facilities that pursue a compliance pathway requiring one of these technologies, there are multiple issues that could affect the ability to complete projects on the

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[13] *Id*. at 10.

[14] *See id.* at 13.

proposed timelines or to consistently operate as designed and, thus, pose significant reliability concerns due to the potential unavailability of energy from these affected units. Some of these issues include:

- Delays and, in some cases, cancelation of CO_2, natural gas, and hydrogen pipeline construction
- Lack of a mature supply chain for CCS equipment
- Supply chain disruptions
- Labor shortages for construction of emissions control equipment
- CO_2, natural gas, or hydrogen pipeline disruptions
- Performance challenges of control equipment

To avoid the risk from these significant uncertainties and the expected high cost of implementing the proposed control technologies, it may be necessary for some units to pursue an alternative compliance pathway that provides more certainty, including early retirement and/or severe capacity factor limitations. The loss of capacity and energy from these firm, dispatchable generating units can lead to capacity and energy deficits for the grid that pose significant reliability concerns. Mitigation of these reliability impacts will require extensive coordinated planning, permitting, construction, and commissioning of replacement energy and capacity resources along with new transmission facilities and other infrastructure.

C. A Broad Range of Reliability Concerns Must Be Addressed in the Final Rule

EPA is requesting comment in the SNPR on mechanisms to address reliability needs that may arise during implementation of the final rules. EPA identifies two sets of "circumstances and conditions" that could raise concerns with reliability:

> *(i) concerns driven by events, such as extreme weather, unexpected generator outages, unanticipated transmission line disruption; and*

> *(ii) concerns driven by supply chain or construction delays or disruptions for new generation, transmission lines, or other infrastructure as well as delays in permit issuance for controls required to meet the standards of performance[.]*[15]

While we agree with EPA that these situations can pose serious risk to reliability and the ability to serve load or maintain the stability of the electric grid, there are additional drivers of reliability concern that EPA must also address.

Foremost, neither of the two listed areas of concern accounts for the fact that supply chains do not currently exist for low-GHG hydrogen supply or carbon capture equipment for the electric sector. Furthermore, there is currently only a single facility in the U.S. (i.e., Petra Nova) that is equipped with carbon capture capability, and that facility has not demonstrated consistent performance that meets the capture requirements of this proposal.

D. Adequate Time is Needed for Robust Long-Term Planning and Implementation that is Critical for Reliability

Major fleet transition projects, where large central station generating facilities, such as Plants Bowen[16] and Miller,[17] are retired and new generation is added, will require significant updates to the transmission and electric generation infrastructure, including construction and commissioning of new generating units and new transmission facilities, 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 like Plants Bowen and Miller, 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 the new power plants that will be

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[15] 88 Fed. Reg. 80,682, 80,684 (Nov. 20, 2023).

[16] Plant Bowen, located in Bartow County, GA, is one of the largest power plants in the country with four coal-fired electric generating units with a total nameplate capacity of approximately 3,200 MW. Plant Bowen is owned and operated by Georgia Power Company.

[17] The James H. Miller Electric Generating Plant, located in Jefferson County, AL, is one of the largest power plants in the country with four coal-fired electric generating units with a total nameplate capacity of approximately 2,500 MW. Plant Miller is owned and operated by Alabama Power Company.

needed to both replace retiring generation and meet the increasing needs of growing populations and economies, including increasing electrification in the transportation and industrial sectors. 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 coordination of multiple project-specific planning schedules can result in extended schedules for some projects, potentially restricting a project's ability to comply with the compliance timelines specified in the proposed rule.

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;
- New environmental compliance plans for existing units;
- Unit retirements;
- Transmission projects;
- Requests for Proposals;
- Certification of additional generation resources; and
- Other interrelated activities.

All of these activities will necessarily be predicated on the scope of work required to comply with an EPA-approved state plan. Hence, for existing units, these project timelines cannot substantially move forward prior to the date of EPA's approval of the relevant 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). 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 and approved by the PSC as part of statutorily required, triennial IRP proceedings, 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 and the Southern Company system 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 install emissions controls or retire and replace generating resources. To modify its generation portfolio, Georgia Power generally must follow PSC rules which, for large 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 RFPs and certifications, which are required by the PSC and are applicable to Georgia Power, typically require time frames between 19 and 30 months before resources are certified and 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. 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 rigorous state regulatory process requirements (of which the Georgia process described above is one illustrative example) in establishing any guidelines around timelines for installation of control technologies or unit retirement commitments. In establishing compliance deadlines for the proposed rules, EPA should adequately account for the extensive state plan processes and should anchor all compliance dates to the date that state plans are approved by EPA or when a federal plan is finalized and becomes effective, allowing for the subsequent state PSC processes that are required before initiating major investments in or new construction of generation.

E. Combustion Turbines are Critical for Maintaining Reliability Through the Fleet Transition

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. As coal-fired EGUs continue to retire over the coming years, new and existing 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. To that end, it is important for EPA to ensure that new, efficient combustion turbines can be constructed and operated so that the electric needs of the U.S. continue to be met in a reliable and affordable manner during the energy transition.

IV. Potential Tools for Addressing Reliability Concerns

The reliability challenges posed by this rule are substantial, and EPA must carefully consider the drivers of reliability risk and the tools that might help lessen that risk. The proposed BSER and implementation timelines raise a range of reliability concerns and challenges, and no single tool can address each of these concerns. Owing to the critical importance of maintaining reliability of

the electric grid in the face of significant economic development while the power sector transitions toward net zero, we urge EPA to be circumspect in its regulatory approach and provide a broad range of tools and flexibilities in final 111 rules and emission guidelines to help ensure reliability of the electric grid in vertically integrated state regulated markets as well as in RTO/ISO markets. Foremost, significantly extending the proposed timelines for compliance would provide a better opportunity for technology and infrastructure advancement to reduce both reliability and cost impacts over time. As we explain in our prior comments on this rulemaking,

- The proposed compliance deadlines for the medium- and long-term coal-fired EGU subcategories should be extended by at least six years.
- The proposed capacity factor limitation for the near-term coal-fired EGU subcategory should be increased to at least thirty percent.
- The proposed compliance deadlines for hydrogen compliance pathways for new and existing combustion turbines should be extended by at least five years.
- The proposed compliance deadline for the CCS compliance pathways for new and existing combustion turbines should be extended by at least five years.
- The proposed capacity factor thresholds for new base load and "large and frequently operated" existing combustion turbine subcategories should be increased to at least sixty-five percent.
- The proposed thresholds for the new low load combustion turbine subcategory should be increased to at least twenty-five percent.

Furthermore, EPA should include other flexibilities and tools to help protect reliability of the electric grid while also helping maintain affordability by reducing the cost to mitigate risks and impacts to customers.

A. EPA Should Clarify that Reliability Is an Important "RULOF" Factor and that States are Particularly Suited to Assess and Account for It.

Section 111(d) is a hallmark of the cooperative federalism model that Congress has embedded throughout the CAA. Under that framework, 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." This provision of the CAA delegates broad authority to states to address unique situations and circumstances in applying standards of performance to sources under their purview.

Congress's decision to rest with each state the substantive decision-making regarding the regulation of existing EGUs under section 111(d) makes eminent sense given significant changes in the electric grid are occurring at an unprecedented pace, including historic load growth, retirements of substantial amounts of dispatchable generation, rapidly growing amounts of variable renewable generation, and the extensive transmission buildout 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.

In the proposal, EPA posits that 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." 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 the context of the scope of changes that will be required to comply. In addition to time necessary for siting, engineering, permitting, regulatory approval, procurement, and construction of replacement generation and the timeline for CO_2 and natural gas pipeline development, the associated transmission and reliability impacts from retirement of large central station generators will often require significant infrastructure upgrades that 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 to address reliability concerns. 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 for the unit's desired subcategory. EPA should make clear that states have the flexibility to tailor the application of performance standards to reflect 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 feasible. 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. 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. The proposed "medium" and "long-term" subcategories are not feasible for Plant Bowen because investing the sums necessary to be able to meet those presumptively approvable emission limits would not be fiscally prudent given that the Plant will be retired in 2035, and even if the cost was not prohibitive, it would be difficult—if not impossible—to put in place the equipment and/or infrastructure needed for those subcategories by 2030.

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 and should account for them when these states establish 111(d) emission standards for sources within their jurisdictions.

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 coal-fired 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 resource planning models due to the distant retirement dates currently expected for these units. Replacement of Plant Miller's generation and capacity is not feasible 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 permitted, constructed, and commissioned prior to 2030, eliminating the proposed "medium-term" pathway in the proposed emission guidelines as a viable option for Plant Miller. Similarly, designing, permitting, 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.

Section 111(d) of the Clean Air Act expressly gives states the ability to "take into consideration, among other factors, the remaining useful life of the existing source" when establishing an emissions limitation for that source. EPA also has this authority when it is establishing a federal plan. Southern Company believes that the "other factors" prong of RULOF encompasses electric reliability and allows states (or EPA in the case of a federal plan) to impose less stringent requirements or longer compliance timelines to address reliability issues. EPA should make clear in the final emission guidelines that reliability issues do fall within the "other factors" prong of RULOF and can provide the basis for a state to impose a less stringent emission limitation than the emission guideline provides.

B. EPA Should Provide Time for a Reliability Assessment by the Appropriate Balancing Authority or Reliability Coordinator During the State Plan Development Process

In any final rule, EPA should provide time in the state plan development process to require a reliability assessment to be conducted by the appropriate balancing authority or reliability authority to ensure that the state plans in the region for which the authority is responsible will not cause or exacerbate any reliability issues. This idea was offered to EPA in joint comments filed by Electric Reliability Council of Texas, Inc. (ERCOT), Midwest Independent System Operator, Inc., PJM Interconnection, L.L.C. (PJM), and Southwest Power Pool, Inc. In their comments, these reliability authorities proposed

> *the adoption of an additional sub-category that would accommodate units deemed needed for reliability, whether natural gas or coal. This subcategory would be populated with specific units or locations as identified by the ISO/RTO where unit retirement would cause significant reliability challenges until other longer-term solutions, such as transmission, demand response, or new generation resources, would obviate the need for those units. The ISO/RTO would identify these units or locations to EPA and a unit's placement in this sub-category would allow the non-compliant units to continue to operate beyond the*

> *date of compliance with the rule until the alternative solution can be placed into service.*[18]

We agree that there should be a process where the applicable balancing and reliability authorities review the draft state plans for its territory to analyze whether unit retirements or restrictions on operations under the state plan might cause reliability problems. If the balancing or reliability authority identifies units in the draft state plan that need to retire later or need to operate above the capacity factor restriction set out in the draft state plan, the state plan could then be modified accordingly to address the reliability issues identified by the balancing or reliability authority. This approach would help respond to NERC's recommendation in its 2023 Long-Term Reliability Assessment that retirements of EGUs be carefully managed. NERC recommended that balancing and reliability authorities:

> *need to have mechanisms they can employ to extend the service of generators seeking to retire when they are needed for reliability, including the management of energy shortfall risks. Regulatory and policy-setting organizations must use their full suite of tools to manage the pace of retirements and ensure that replacement infrastructure can be timely developed and placed in service.*[19]

The reliability assessment process proposed here would provide a mechanism that would allow the balancing and reliability authorities to delay retirements and/or adjust operating constraints where needed.

C. Averaging and Trading Are Important Reliability-Related Tools that Provide Compliance Flexibility.

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

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[18] Joint Comments of Electric Reliability Council of Texas, Inc., Midwest Independent System Operator, Inc., PJM Interconnection, L.L.C., and Southwest Power Pool, Inc. at 10 (Aug. 8, 2023), EPA Docket ID No. EPA-HQ-OAR-2023-0072-0673 ("Joint Comments of ISOs/RTOs").

[19] NERC 2023 Long-Term Reliability Assessment at 13.

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 and across different subcategories of affected facilities. EPA has recognized that these types of market-based tools "have proven to be extremely effective" and "can achieve substantial reductions in pollution." Analysis has also shown that these types of programs do not disproportionately burden environmental justice communities.

Southern Company encourages EPA to allow states to select 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 or lb/mmBtu), 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 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 appropriate 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. The Proposed System Emergency Provisions Must be Clarified and Revised

In the SNPR, EPA notes that "events, such as extreme weather, unexpected generator outages, and unanticipated transmission line disruption"[20] may pose concerns for reliability of the electric grid. These acute events can lead to urgent situations requiring immediate action to help maintain the proper functioning of the electric system.

EPA should include a mechanism to address such urgent reliability events in the final 111 rule, and the power to activate this mechanism should rest with the applicable Balancing Authority or Reliability Coordinator. Any emissions or operations that occur during a reliability event (defined as a "system emergency" in the regulations) as a result of an affected unit operating at the direction

[20] 88 Fed. Reg. at 80,684.

of the Balancing Authority or Reliability Coordinator would be excluded from the compliance determination required under the rule.

As a preliminary matter, at the recent Annual Reliability Technical Conference put on by the Federal Energy Regulatory Commission ("FERC"), Joseph Goffman, the Principal Deputy Assistant Administrator, for the EPA Office of Air and Radiation, mentioned enforcement discretion "in situations where compliance is not achievable within the requisite timeframe, and the operation of the unit is needed for reliability."[21] Enforcement discretion is not an adequate tool for addressing reliability concerns as it does not provide certainty to the owners and operators of affected EGUs that they will not be held liable for being out of compliance with their emission standard. Nor does it protect owners and operators of EGUs from state or citizen suit enforcement. Any commitment by EPA not to enforce emission standards during reliability events needs to be clearly set out in the final rule.

We urge EPA to make the following changes to the definition of "system emergency" in both Subpart TTTT and proposed Subpart TTTTa to clarify which entities have the authority to make a system emergency determination and to help ensure a more comprehensive range of reliability emergencies can be addressed:

- Instead of referencing "the Regional Transmission Organizations (RTO), Independent System Operators (ISO) or control area Administrator," the definition should reference "the Balancing Authority or Reliability Coordinator." This change would align the regulation's definition with the terms used by NERC to describe the roles that are responsible for the reliable function of the grid. The terminology for the entities that determine a system emergency should be aligned with NERC's terminology.
- The definition should be expanded to include the concept of energy emergencies. NERC defines an energy emergency as: "A condition when a Load-Serving Entity or Balancing

[21] FERC, Transcript, 2023 Reliability Technical Conference, Docket No. AD23-9-000 at 162:19-22 (Nov. 9, 2023), https://www.ferc.gov/media/transcript-docket-no-ad23-9-000 ("FERC Transcript").

Authority has exhausted all other resource options and can no longer meet its expected load obligations."

These changes would result in the following system emergency definition in the final rule:

> *System emergency means (a) any abnormal system condition that the ~~Regional Transmission Organizations (RTO), Independent System Operators (ISO) or control area Administrator~~ Balancing Authority or Reliability Coordinator determines requires immediate automatic or manual action to prevent or limit loss of transmission facilities or generators that could adversely affect the reliability of the power system, or (b) a determination by the balancing authority or reliability coordinator that a load-serving entity or balancing authority has exhausted all other resource options and can no longer meet its expected load obligations, and therefore permits the balancing authority or reliability coordinator to call for maximum generation resources to operate in the affected area, or for ~~the~~ a specific affected EGU to operate to avert loss of load.*

EPA could also add the following NERC definitions to the final rule to provide additional clarity to the system emergency definition (although these terms are commonly known so this may not be necessary):[22]

> *Balancing Authority: The responsible entity that integrates resource plans ahead of time, maintains Demand and resource balance within a Balancing Authority Area, and supports Interconnection frequency in real time.*
>
> *Reliability Coordinator: The entity that is the highest level of authority who is responsible for the Reliable Operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.*

The proposed rule also "include[s] a provision that electricity sold during hours of operation when a unit is called upon to operate due to a system emergency is not counted toward the percentage

[22] https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf

electric sales subcategorization threshold."[23] EPA says it "concluded that this exclusion is necessary to provide flexibility, to maintain system reliability, and to minimize overall costs to the sector."[24] Net-electric sales are used in the proposed rule to help define the subcategory of an affected unit.[25] For example, the subcategory definition for base load combustion turbines requires that a unit "[s]upplies more than its design efficiency times its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis."[26] While this provision may be helpful for units that are in subcategories that require annual capacity factor limitations, it does not help for situations where a unit's control technology is not functioning properly, and the unit is needed in an emergency for reliability of the grid. For example, under the proposed rule, a new base load combustion turbine that elects the CCS pathway must meet an emission standard of 90 lb CO2/MWh-gross beginning in 2035.[27] If the CCS equipment is not functioning properly, the declaration of a system emergency by the balancing authority or reliability coordinator will not help this unit. If it operates as needed to provide electricity during the system emergency, it will exceed its emission standard.

To resolve this problem, we suggest the following modification to Proposed 40 C.F.R. § 60.5525a(a):

> *(a) You must be in compliance with the emission standards in this subpart that apply to your affected EGU at all times, with the exception of emissions that occur during a system emergency at the direction of the Balancing Authority or Reliability Coordinator. However, you must determine compliance with the emission standards only at the end of the applicable operating month, as provided in paragraph (a)(1) of this section. Any emissions that occur during a system emergency at the direction of the Balancing Authority or Reliability Coordinator are excluded from this compliance determination. You have a duty*

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[23] 88 Fed. Reg. at 33,333.

[24] *Id.*

[25] *See* Proposed Table 1 of Subpart TTTTa of Part 60.

[26] *Id.*

[27] 88 Fed. Reg. at 33,325, Table 3.

> *to minimize emissions to the extent practicable during system emergencies. Any combustion turbine burning hydrogen fuel for compliance purposes must only combust low-GHG hydrogen.*

This same reliability safety valve should also be provided to existing units. We suggest the following modifications to Subpart UUUUb (Emission Guidelines for Greenhouse Gas Emissions for Electric Utility Generating Units) would accomplish this goal:

- Add the definition above for "system emergency" to Proposed 40 C.F.R. § 60.5880b.[28]
- Make the following revision to Proposed 40 C.F.R. § 60.5860b(d):

> *(d) Your plan must require the owner or operator of an affected EGU covered by your plan to include in a report submitted to you the information in paragraphs (d)(1) through (4) of this section. CO_2 emissions that occur during a system emergency at the direction of the Balancing Authority or Reliability Coordinator are excluded from the information required to be included in the report.*

Additionally, EPA should allow the Balancing Authority or Reliability Coordinator to call on units when they foresee the possibility of a system emergency rather than waiting until an emergency is declared. For coal-fired generation, it typically takes 18 hours or more to bring an idle unit to full output and for combined cycle generation it can take 3 to 4 hours to bring an idle unit to full output. Therefore, it is important that EPA allow the Balancing Authority or Reliability Coordinator to call on units in advance of a significant risk of an emergency rather than being forced to wait until the emergency is declared.

Finally, EPA indicates in the preamble to the proposed rule that the system emergency provision would not apply to units that are already running when the system emergency is declared. There is no basis for EPA to limit the applicability of this provision only to units that were not running when the emergency was declared. Units approaching their electric sales threshold would, under normal circumstances, have the option of shutting down. The system emergency may necessitate

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[28] If EPA adds the definitions of balancing authority and reliability coordinator to Subpart TTTT and Subpart TTTTa, it should also add them to Subpart UUUUb.

that the unit continue to run, however, even though it may cause the unit to exceed its electric sales threshold.

E. EPA Should Include a Mechanism to Extend Compliance Deadlines if Technologies and Infrastructure Supply Chains to do not Mature at the Pace EPA has Anticipated.

EPA should add a process to the emissions guidelines to monitor the status and advancement of technologies that have been identified as BSER (e.g., CCS, low-GHG hydrogen co-firing), and adjust existing EGUs' compliance schedules as necessary to reflect the availability of such technology. Monitoring the status/progress of required technology is imperative to ensure that retirement of dispatchable generation is balanced with the application of control technologies on existing sources and new replacement resources. For example, if low-GHG hydrogen production/deployment and CCS experience technological or infrastructure hurdles, this monitoring process would help ensure that control requirements for affected generating units could be delayed until the required technology is available, which may vary by region. EPA should provide states with the flexibility to implement extensions, as well as other related flexibilities, directly into their Section 111(d) state plans so that such extensions and flexibilities can be triggered under an existing approved state plan without a state first having to revise its plan, submit it to EPA, and wait for EPA approval before the measures can be implemented. EPA should provide relief from any condition or timeline that is contingent on development of infrastructure or construction of replacement generation that is experiencing delay well in advance of the applicability of such condition or timeline.

F. Existing Tools Are Inadequate to Address Reliability Concerns Raised by the Proposed Rule.

While there are some existing mechanisms that have been suggested by commenters as potential reliability tools, these should not be relied upon to address the potential issues raised by the proposed section 111 rules in their current form.

For instance, Federal Power Act (FPA) section 202(c) emergency orders should not be depended upon to address the reliability issues discussed above. This provision is only to be invoked by the Secretary of Energy in extreme circumstances. In fact, it has been applied only twenty times in over twenty years. Further, it is only intended to be a temporary measure to address limited extreme

circumstances, and it does not provide protection from citizen suits under the Clean Air Act. While emergency orders that are issued by the Secretary of Energy should be included in the "system emergency" definition, these types of orders alone are not sufficient to provide the relief under the proposed rules that is needed during an emergency situation to help ensure reliability. Nor do they address the long-term reliability concerns posed by the proposed rules.

Similarly, certain emergency agreements that utilities have in place with their neighbors should not be counted on to address issues created by proposed section 111 rules. Pursuant to these agreements and consistent with NERC Standard EOP-011, the Reliability Coordinator declares an Energy Emergency Alert (EEA) (at varying levels as appropriate) and works with the Balancing Authorities and Transmission Operators in its area to address the issue. By the very name of this family of NERC Emergency Preparedness and Operations (EOP) standards, they are intended to address energy emergencies that occur in the real- or near-time operating horizon, and were not intended to address generation or transmission adequacy issues from a long-term planning standpoint brought about by operating restrictions or the planned or required retirement of generating resources. Further, while these agreements are triggered by emergency situations, they are only useful if there is excess generation available. Under the proposed section 111 rules, which affect generating units across the U.S., there is likely to be less excess generation available on any systems, making reliance on these emergency agreements impractical. Similar to 202(c) emergency orders, emergency agreements do not alleviate the compliance risk to units that are needed during these emergencies, nor do they address the long-term reliability concerns posed by the proposed rules.

V. Conclusion

Southern Company appreciates EPA recognizing that the proposed 111 rules for GHG emissions from the power sector raise serious reliability concerns. 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 associated expansion and adjustments to transmission and pipeline infrastructure, as existing fossil generating units retire. Southern Company supports regulatory action that achieves GHG emissions reductions from the electric sector, and we urge

EPA to provide adequate time frames and the flexible tools necessary to support an orderly fleet transition that maintains an affordable and reliable electric grid.

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. We commit to collaboration on this rulemaking, and we look forward to continuing our engagement with the Agency on this topic.

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.