STEPTOE & JOHNSON PLLC
ATTORNEYS AT LAW

Chase Tower, 17th Floor
P.O. Box 1588
Charleston, WV 25326-1588
304-353-8000
Fax: 304-933-8704
www.steptoe-johnson.com

Writer's Contact Information
Kathy.beckett@steptoe-johnson.com
304-353-8172

August 4, 2025

U.S. Environmental Protection Agency
EPA Docket Center
Docket ID No. EPA-HQ-OAR-2025-0124
Mail Code 28221T
1200 Pennsylvania Avenue NW
Washington, DC 20460

RE: Proposed Repeal of Greenhous Gas Emissions Standards for Fossil Fuel-Fired Electric Generating Units; Docket No. EPA-HQ-OAR-2025-0124-0001.

To Whom It May Concern:

The Midwest Ozone Group ("MOG")[1] is pleased to have the opportunity to offer comments in support of the proposed rule of the United States Environmental Protection Agency ("EPA") that was published in the Federal Register on June 17, 2025, (90 Fed. Reg. 25,752) entitled "Repeal of Greenhouse Gas Emissions Standards for Fossil Fuel-Fired Electric Generating Units". Comments on the proposed rule must be received on or before August 7, 2025.

---

[1] The membership of the Midwest Ozone Group includes: Ameren, American Electric Power, American Forest & Paper Association, American Iron and Steel Institute, American Wood Council, Appalachian Region Independent Power Producers Association, Associated Electric Cooperative, Berkshire Hathaway Energy, Big Rivers Electric Corp., Citizens Energy Group, City Water, Light & Power (Springfield IL), Cleveland-Cliffs Inc., Council of Industrial Boiler Owners, Duke Energy Corp., East Kentucky Power Cooperative, ExxonMobil, Monongahela Power Company, Indiana Energy Association, Indiana-Kentucky Electric Corporation, Indiana Municipal Power Agency, Indiana Utility Group, Hoosier Energy REC, inc., LGE/ KU, Marathon Petroleum Company, National Lime Association, North American Stainless, Nucor Corporation, Ohio Utility Group, Ohio Valley Electric Corporation, Olympus Power, Steel Manufacturers Association, and Wabash Valley Power Alliance.

Based on a reassessment of the legal and technical conclusions in the 2015 NSPS for Electric Utility Generating Units (80 Fed. Reg. 64,510, October 23, 2015) and the 2024 Carbon Pollution Standards ("CPS") (89 Fed. Reg. 39,798, May 9, 2024), EPA is offering a Primary Proposal to repeal the GHG emissions standards for new and existing sources in the fossil fuel-fired power plant source category of section 111.

As an Alternative Proposal, EPA is proposing among other things to determine that 90% CCS is not the best system of emission reductions ("BSER") for existing long-term coal-fired steam generating units because 90 percent CCS has not been adequately demonstrated and its costs are not reasonable. EPA proposes to conclude that experimental projects aiming to achieve 90% CCS were not a sufficient basis to conclude the technology has already been adequately demonstrated. Furthermore, because it is extremely unlikely that the infrastructure necessary for CCS can be deployed by the January 1, 2032, compliance date, the EPA is proposing to determine that the degree of emission limitation in the CPS for long-term coal-fired steam generating units is not achievable. EPA also offers an alternative proposal that 40 percent natural gas co-firing is not the BSER for existing medium-term coal-fired steam generating units because natural gas co-firing in a steam generating unit is an inefficient use of natural gas. EPA proposes to conclude that 40 percent natural gas co-firing constitutes impermissible generation shifting under *West Virginia*, and that the Agency erred in the CPS by construing *West Virginia* too narrowly in this respect. EPA proposes that the associated degree of emission limitation is not achievable because it is extremely unlikely the necessary pipeline infrastructure can be deployed in the time provided under the CPS. Based on these proposed conclusions, EPA is proposing to repeal the requirements in the emission guidelines related to existing long-term and medium-term coal-fired steam generating units. Additionally, EPA is proposing to repeal the requirements in the emission guidelines related to natural gas-and oil-fired steam generating units because it would be an inefficient use of State resources to develop, submit, and implement State plans solely for natural gas-and oil-fired steam generating units, which comprise a relatively small part of the source category and would result in few or no emission reductions under the existing emission guidelines.

While EPA's Alternative Proposal, does not offer any certain regulatory action with regard to BSER determinations or standards of performance and related requirements for new and reconstructed intermediate load and low load fossil fuel-fired stationary combustion turbines or for phase 1 for new and reconstructed base load fossil fuel-fired stationary combustion turbines, or the 2015 NSPS or substantive elements of 40 CFR part 60, subpart TTTT, EPA has specifically requested comment on these issues and states that it may, if appropriate, engage in further rulemaking at a future date if this alternative proposal is finalized.

Summary of Comments

As will be shown in these comments, MOG supports EPA's Primary Proposal to repeal all of the GHG requirements set forth in 40 CFR part 60, subparts TTTT, TTTTa and UUUUb on the basis of its conclusion that greenhouse gas ("GHG") emissions from fossil-fired EGUs do not contribute significantly to dangerous air pollution, that cost-effective control measures are not reasonably available, and that public health and welfare are promoted through energy dominance and independence secured by using fossil fuels to generate power.

As will be demonstrated in these comments, and based on the report "Analysis of Carbon Capture Utilization and Sequestration Technology As BSER Under the 2024 Greenhouse Gas (GHG) and New Source Performance Standards" prepared by by J. Edward Cichanowicz and Michael C. Hein ("Cichanowicz/Hein CCUS Report"), s*ee* Attachment A and incorporated into these comments), the proposed determination that CCUS for either coal-fired or NGCC application is not commercially demonstrated and therefore not a cost effective control measure reasonably available.

With respect to EPA's Alternative Proposal, which sets forth an Alternative Proposal to repeal the phase 2 requirements related among other things to 90% CCS and 40% co-firing, MOG strongly supports EPA's conclusion that these requirements do not constitute BSER as is required by the Clean Air Act. While EPA stopped short of repealing all of the GHG requirements that were included in the primary proposal, EPA has, however, requested comment on its BSER determination and standards of performance and related requirements related to the phase 1 controls. In doing so EPA states that it may, if appropriate, engage in further rulemaking at a future date.

As will demonstrated in these comments, and based on the report "Analysis of Combustion Turbine CO2 Emission Rates Under the 2024 Greenhouse Gas (GHG) New Source Performance Standards (NSPS) for Fossil-Fired EGUs" prepared by J. Edward Cichanowicz and Michael Hein ("Cichanowicz/Hein CT Report" (s*ee*, Attachment B and incorporated into these comments), the remaining requirements of 40 CFR part 60, subparts TTTT, TTTTa and UUUUb are fatally flawed and cannot be implemented as requirements that are legally and technically justified. MOG urges the agency to reconsider these requirements and to provide expeditious relief from the imposition of these requirements and the adverse impact of those requirements on the cost of electricity and grid reliability.

Specifically, the Cichanowicz/Hein CT Report demonstrates significant errors in the control requirements for base load and intermediate load units including (1) EPA's failure to account for variations in turbine design (2) EPA's failure to recognize the emission rates are not based on broadly available technology (3) EPA's failure to explain why any unit that does not meet the specific design of the best performing unit can meet the selected standard and (4) EPA's use of 40% capacity factor as the threshold for practically requiring a combined cycle configuration is not justified. In addition, the Report notes (p. 23) that EPA did not identify high turbine inlet pressures as a component of BSER. The Report also notes (p. 25) that EPA was in error when it concluded (89 Fed. Reg. 39,947) that the phase 1 performance standard of 800 lb. CO2/MWh is achievable for all new large, combined cycle EGUs with an acceptable compliance margin.

Accordingly, given the fact that EPA is proposing to <u>repeal</u> all GHG controls as part of its Primary Proposal, and given the fact that EPA is proposing to <u>repeal</u> its phase 2 controls (90% CCS and 40% co-firing) as part of its alternative proposal, if EPA determines to finalize the Alternative Proposal, for the reasons set forth in these comments, MOG urges that EPA expeditiously initiate a new rulemaking in light of these comments to reconsider the requirements of subparts TTTT, TTTTa and UUUUb that are not being repealed and to take immediate action to avoid the imposition of those requirements while the new rulemaking is being undertaken.

<u>Comments On Primary Proposal</u>

As a matter of Clean Air Act law, EPA is asserting that section 111 is best read to require, or at least authorize EPA to require, a determination that an air pollutant emitted by a source category causes, or contributes significantly to, dangerous air pollution <u>as a predicate</u> to establishing emissions standards for that pollutant. This proposal would reverse previous EPA interpretations and rulemakings that omitted making the significant finding for GHG emissions from existing sources. Today's proposal finds EPA's previous rulemakings (2015 and 2024) as unlawful because of the lack of an assessment/determination concerning GHG emissions from the targeted existing NSPS EGUs. EPA proposes a determination that once a new source category is listed by EPA pursuant to section 111(b) EPA is required to exercise judgment in determining which air pollutants to regulate by determining whether an air pollutant contributes significantly to dangerous air pollution. In summary, EPA exercises judgment in determining which source categories to list for regulation under CAA section 111(b)(1)(A); after listing a source category, EPA has discretion in determining which pollutants to regulate; and once EPA has determined to regulate a particular air pollutant, it has discretion in determining the type of controls (BSER) that serve as the basis for the regulation under CAA section 111(a)(1). EPA is proposing to determine that GHG emissions from fossil fuel-fired EGUs do not contribute significantly to dangerous air pollution for the purposes of CAA section 111(b) concerning new sources, therefore rescinding the 2015 NSPS by repealing all GHG emissions standards and guidelines for the power sector. EPA arrives at this conclusion because of the inability to develop BSER that would result in any meaningful, cost-reasonable GHG emission reductions, the contribution of this source category to GHG air pollution is not significant. Additionally, EPA's proposal concludes that only extraordinary emissions reductions on a global scale would have any impact on the potential endangerment of public health and welfare in this context.

The Cichanowicz/Hein CCUS Report (Attachment A) offers a full assessment of the following key points, but full assessment of this report is requested.

- Experience with carbon capture utilization and storage (CCUS) at industrial scale does not reflect utility duty, as most industrial applications deploy CCUS as a slipstream of the source rather than integrated for 24x7 duty over the load cycle.

- Although many FEED studies are in progress and results not released, there are no definitive, funded demonstration projects underway. The report assesses ten FEED studies for coal-fired and 9 for natural gas/combined cycle (NGCC) firing.

- Operating experience of Sask Power Boundary Dam Unit 4 is re-evaluated, considering information submitted by the project operator not previously disclosed. New information shows Boundary Dam Unit 4 CCUs enjoyed a flexibility in duty that would not fully qualify as a commercial demonstration in the context of the proposed GHG rule. Similarly, the Petra Nova experience is re-assessed in this manner.

- Capital cost estimates of CCUS processes are updated to include one additional coal-fired unit not available in August 2023, with costs for all studies presented in the same cost year (2022). These results show the capital cost for CCUS, as applied to either coal-fired of NGCC generation, requires as much or more capital than necessary for a new, greenfield state-of-art coal-fired or NGCC generating asset without CCUS.

- An update of the permitting activities for CO2 pipelines in the Midwest is presented, summarizing the recent permit denials and project cancellation for Navigator Ventures, and permit denial for Wolf Carbon Solutions. In contrast, the Summit pipeline has secured permits in Iowa, North Dakota, and Minnesota, but continues to experience resistance and permit rejection in South Dakota.

In conclusion, the Cichanowicz/Hein CCUS Report supports the agency proposal that CCUS for either coal-fired or NGCC application is not commercially demonstrated.

MOG supports EPA's proposed legal analyses and conclusions. MOG has historically stated and again expresses its concern for generation shifting that is not authorized by CAA section 111. The major questions doctrine invoked by the Supreme Court recognizes that "in certain extraordinary cases, both separation of powers principles and a practical understanding of legislative intent makes [courts] reluctant to read into ambiguous statutory text the delegation [to an agency] claimed to be lurking there." *West Virginia, et al. v. Environmental Protection Agency, et al.*, 597 U.S. 697, 723 (2022).

MOG also supports the legal conclusion that rule for EGUs was an overreach based upon "newfound power" in a decades old statute, reaching into the realm of a major question, by promoting broad assumptions driving guaranteed changes in the energy sector. MOG supports EPA's current proposal that concludes it was legally improper for the rule to focus on developing technologies that were neither adequately demonstrated nor commercially available.

DOE represented in 2022 that there were 12 carbon capture and storage projects in the United States with a total capacity of 20 million metric tons of carbon dioxide ("CO2") per year. By 2030, carbon capture projects were predicted to capture and store 128 million metric tons of carbon dioxide in the US. USDOE "Carbon Capture, Use, Transport, and Storage," Fact Sheet, June 20, 2023. DOE identified economic and commercial factors impacting carbon capture and storage as follows: cost uncertainty, as project costs remain high for some types of point-source CCUS applications and early deployments of certain CDR technologies; demand uncertainty, driven by an absence of compliance markets and limited evidence of bankable revenue streams for low-carbon products and voluntary carbon removals; lack of commercial standardization for the partnerships and commercial arrangements carbon management projects will require' execution factors; lead times in permitting storage infrastructure which many developers see as a potentially lengthy and uncertain process; lack of transport and storage infrastructure in some areas could slow execution of capture projects; and local opposition to project development in some instances. USDOE, "Pathways to Commercial Liftoff: Carbon Management," April 2023. p. 22. Within the "Congressional Research Service: Carbon Dioxide Pipelines: Safety Issues" report it is estimated that 66,000 miles of pipeline will be needed for CO2 lines to support CCS. MOG supports the current proposal based upon the speculative nature of CCS as a readily available technology.

Comments on Alternative Proposal

EPA alternatively proposes the following:

- Not to reopen the BSER determinations or standards of performance and related requirements for new and reconstructed Phase 1 base load fossil fuel-fired stationary combustion turbines and new and reconstructed intermediate load and low load fossil fuel-fired stationary combustion turbines or the 2015 NSPS or substantive elements of 40 CFR Part 60, subpart TTTT.

- To determine that 90 percent CCS is not the BSER for existing long-term coal-fired steam generating units. Because of infrastructure limitations for CCS deployment, EPA is proposing to determine that the degree of emission limitation in the CPS for long-term coal fired steam generating units is not achievable.

- To determine that 40 percent natural gas co-firing is not the BSER for existing medium-term coal-fired steam generating units because consideration of the energy requirements shows that 40 percent natural gas co-firing in a steam generating unit is inefficient use of natural gas.

- To repeal the requirements for existing natural gas and oil-fired steam generating units because it would be an inefficient use of State resources, since it is repealing the coal-fired unit requirements.

- To repeal the CCS-based requirements for coal-fired steam generating units undertaking a large modification.

- To determine 90 percent CCS is not BSER for new base load combustion turbines.

The Agency is soliciting comments on BSER or standards of performance and related requirements for new and reconstructed Phase 1 base load fossil fuel-fired stationary combustion turbines and new and reconstructed intermediate load and low load fossil-fired stationary combustion turbines or ("CTs"). Summary excerpts are provided in responses below to C-13 and C-14, illustrating that Phase I controls are inappropriate and should not be implemented. MOG also requests that EPA act expeditiously to provide for near-term relief from these inappropriate limits.

The current Phase 1 performance standards are based on a 12-month rolling average rate in pounds of CO2 per megawatt hours (lbs/MWh), the specific values of which depend on (1) the 12-month capacity factor (i.e., low, intermediate, and base load) and (2) fuel. Cichanowicz/Hein CT Report analyzed CO2 emission rates for natural gas-fired simple-cycle CTs (primarily in the intermediate load category) and combined-cycle CTs (primarily in the base load category). Similar concepts would apply to other fuels, including diesel oil.

The Cichanowicz/Hein CT Report (Attachment B) provides the following key points, but full assessment of this report is requested.

- EPA does not account for how combustion turbine design variants affect CO2 emission rate in the selection of an appropriate standard. The inherent emission rate differences between these various designs impacts the ability to assign an appropriate emission rate.

- An assessment of CO2 emissions obtained from the EPA Air Markets Program Data (AMD) and the specific CTs show that compliance with the present CO2 emission rates is not based on broadly available technology. The Report identifies CTs operations and designs that are unable to meet the CO2 emission rates. EPA failed to adequately pair its technical assumptions with facts about the CT industry.

- Regarding combined cycle applications, EPA notes the actual CO2 emission rate of the population ranges from 720 to 920 lbs/MWh, averaging 810 lbs/MWh. EPA implements so-called "adjustments" that attempt to correct for differences. Additionally, EPA's selection of the Dresden Plant as the "best-performing" unit at 770 lbs/MWh rate as justification for a CO2 emission rate of 800 lbs/MWh lacks appropriate analyses.

- Finally, in the 2024 rule, EPA employed a 2023 NETL study to create numerous reference cases to justify 40% capacity factor as the intermediate load threshold. An overarching concern is that such "static" studies do not always reflect the present marketplace variabilities and can be misleading. Additionally, based on the trends in levelized cost of electricity ("LCOE") extrapolated from the NETL study, EPA established a yearly capacity factor of 40% as the cutoff between intermediate load and base load categories. The Cichanowicz/Hein CT Report demonstrates that the use of 40% capacity factor for combined cycle configuration is not justified.

General Comments

a. Air quality impacts were not presented in a transparent manner in support of the prior rule.

The prior rule was anticipated to only lower power sector carbon emissions by an additional 1% over that which the IRA was predicted to deliver, according to EPA's IPM modeling. An issue of concern at that time was the late release by EPA on July 7, 2023, of a memorandum titled, "Integrated Proposal Modeling and Updated Baseline Analysis." This document had 22 attachments and four new IPM model run outputs, with each model containing 18 separate Microsoft Excel spreadsheet outputs totaling 129 megabytes of data. These new data were released only 21 business days before the close of the comment period. The new data represented a significant change from the original analysis of the proposed rule. EPA failed to provide a reasonable time period for comment to its revised proposal, in violation of the Administrative Procedure Act. MOG urges EPA to avoid such errors in this rulemaking and to provide the public with a meaningful opportunity to review the administrative docket and to provide comment prior to finalizing any new standards of performance.

b. Grid reliability was placed at risk.

The pace of retirements being driven in large part by state laws and federal environmental initiatives that create a clear near-term, date certain requirement for electric generators to comply or retire is creating significant concern by RPOs. The pace of additional new renewable generation is currently slower than anticipated.

The reliability challenge from prematurely losing resources needed to manage the grid dominated by intermittent renewable generation is concerning. There is a critical need for integrating analysis of the reliability impact of specific state and federal policies prior to those policies being adopted. MOG supports this proposal. Prior rulemakings did not take into account the reliability attributes needed by system operators or the feasibility of the cost of the compliance alternatives proposed in the particular rulemaking.

c. Compliance cost impacts.

The unknown variables presented by permitting, supply chain limitations, and available technology for emissions controls are concerning. MOG supports the conclusion that the cost impacts of the current rule were not readily discernible based on the broad scope of the rule. MOG supports this proposed acknowledgement that cost must be a key factor in the development of a section 111 rule.

d. CCUS feasibility

The Cichanowicz/Hein CCUS Report, (Attachment A), presents comments supplemental to those submitted by MOG and others in the 2023 GHG rulemaking process. Since submission of the 2023 report several references have become available, among these submissions by SaskPower regarding Boundary Dam Unit 4, additional capital cost from a completed FEED study, and an update of CO2 pipeline permits in several states.

This report addresses five topics. Section 2 describes how experience with carbon capture utilization and storage (CCUS) at industrial scale does not reflect utility duty, as most industrial applications deploy CCUS as a slipstream of the source rather than integrated for 24x7 duty over the load cycle. The Section 2 discussion highlights how slipstream duty provides flexibility to avoid or minimize complications due to load following – and notes the highlighted utility applications at Petra Nova and – to a lesser extent – SaskPower Boundary Dam Unit 4 – function as a slipstream.

Second, the status of detailed studies of CCUS application – referred to as Front End Engineered Design (FEED) studies- are summarized. Ten such FEED studies for coal-fired and 9 for natural gas/combined cycle (NGCC) firing are identified, denoting those completed and results in the public domain. It is noted although many FEED studies are in progress and results not released, there are no definitive, funded demonstration projects underway.

Third, operating experience of Sask Power Boundary Dam Unit 4 is re-evaluated, considering information submitted by the project operator not been previously disclosed. New information shows Boundary Dam Unit 4 CCUs enjoyed a flexibility in duty that would not fully qualify as a commercial demonstration in the context of the proposed GHG rule. Similarly, the Petra Nova experience is re-assessed in this manner.

Fourth, capital cost estimates of CCUS processes are updated to include one additional coal-fired unit not available in August 2023, with costs for all studies presented in the same cost year (2022). These results show the capital cost for CCUS, as applied to either coal-fired of NGCC generation, requires as much or more capital than necessary for a new, greenfield state-of-art coal-fired or NGCC generating asset without CCUS.

Fifth, an update of the permitting activities for CO2 pipelines in the Midwest is presented, summarizing the recent permit denials and project cancellation for Navigator Ventures, and permit denial for Wolf Carbon Solutions. In contrast, the Summit pipeline has secured permits in Iowa, North Dakota, and Minnesota, but continues to experience resistance and permit rejection in South Dakota. Summit states their intent to continue to pursue access in South Dakota by altering pipeline routing to minimize barriers.

Cumulatively, these five topics – upon being revisited with recent information, support the conclusion that CCUS for either coal-fired or NGCC application is not commercially demonstrated.

<u>Responses to Request for Specific Comment.</u>

C-1. The proposed interpretation of CAA section 111 to require, or at least authorize the EPA to require, an Administrator's determination of significant contribution for the air pollutant under consideration. EPA is proposing that a determination of significant contribution must consider whether such determination would have an influence or effect on the targeted air pollution and the public health or welfare impacts attributed to such air pollution.

EPA is proposing to find that any regulation of GHG emissions from fossil fuel-fired EGUs under CAA section 111 would not have a significant effect on GHG air *pollution and the public health or welfare impacts attributed to such air pollution, and that the contribution of this source category is therefore not significant. EPA has proposed that GHG emissions from those sources are a small and decreasing part of global emissions and cost-effective control measures are not reasonably available.*

The Agency is proposing that a determination of significant contribution must consider whether such determination would have an influence or effect on the targeted air pollution and the public health or welfare impacts attributed to such air pollution. This inquiry necessarily entails considering the policies that would inform the resulting regulation. In this instance, the EPA is proposing to find that any regulation of GHG emissions from fossil fuel-fired EGUs under CAA section 111 would not have a significant effect on GHG air pollution and the public health or welfare impacts attributed to such air pollution, and that the contribution of this source category

The Administration's priority is to promote the public health or welfare through energy dominance and independence secured by using fossil fuels to generate power.

MOG supports the conclusion that CAA section 111 necessarily includes a determination of significant contribution for the air pollutant under consideration, in this case greenhouse gas emissions. The Emissions Database for Global Atmospheric Research ("EDGAR") "GHG emissions of all world countries", 2024 report, https://edgar.jrc.ec.europa.eu/report_2024, indicates United States's GHG emissions from EGUs are approximately 2.8% of the global total. The downward trends in emissions from the domestic sector indicate future years of reduced percentage of EGU GHG emissions. The data indicate fossil fuel-fired EGU emissions from power plants do not significantly contribute to air pollution which may reasonably be anticipated to endanger public health or welfare either domestically or globally. MOG supports EPA's conclusion that these sources are not section 111 "significant contributors" relative to the increasing emissions of other sectors and countries. Additionally, electric reliability derived from this sector serves to support public health and energy security.

MOG observes that cost-effective controls for fossil fuel-fired EGUs are not reasonably available. The historic record on CCS informs the cost-effective dilemma. Requiring CCS (or even partial CCS) for existing plants "would most certainly have [a]. . . significant effect on nationwide electricity prices and could affect the reliability of the supply of electricity," meaning EPA could "not find. . . the cost to implement" this system "to be reasonable." EPA, GHG Abatement Measures TSD for Proposed Clean Power Plan 7-5 to 7-6 (June 10, 2014). In the Affordable Clean Energy Rule, EPA confirmed "the high cost of CCS, including the high capital costs of operating it, . . . prevent CCS or partial CCS from qualifying" as a permissible system under section 111. 84 Fed. Reg. at 32,548. Estimates of the total amount of tax credits under the 2022 Inflation Reduction Act by the Congressional Budget Office range from "about $5 billion over the 2023-2027 period" to "anywhere from $30 billion to well over $100 billion" "by the early 2030s," CBO, Carbon Capture and Storage in the United States 17 (Dec. 13,2023).

Additionally, not only are those costs a financial burden on operators, but also on consumers of electricity. Historically, EPA informed the U.S. Supreme Court that "the costs to the regulated facility" are "*the most relevant costs*" – not the only ones. 89 Fed. Reg. 39,801.

MOG supports EPA's conclusion that appropriate management of GHG emissions includes assessment of domestic electric reliability and national security. States, grid operators, and the power sector all have gone on record before EPA, warning of impending grid reliability issues as power plants prematurely retire and experience low-capacity factors. EPA is urged to take into consideration increasing electricity demand attributable to many needs to include citizen demand for electrification and heavy-load electricity commercial consumers.

C-2. Whether CAA section 111 requires a significant contribution finding for the fossil fuel-fired EGU source category first created in the 2015 NSPS

MOG supports the conclusion that CAA section 111 necessarily includes a determination of significant contribution for the air pollutant under consideration, in this case greenhouse gas emissions. Based upon data indicating fossil fuel-fired EGU emissions relative to other increasing sectors and countries, MOG supports EPA's conclusion that these sources are not section 111 "significant contributors".

C-3. The proposed interpretation of what it means for a source category to contribute "significantly" to dangerous air pollution.

MOG supports the conclusion that CAA section 111 "significant contributors" necessarily includes an assessment of the sector and country impacts on global GHG emissions trends. MOG supports EPA's conclusion that these sources are not section 111 "significant contributors".

C-4. Any other relevant arguments and information, including with respect to legitimate reliance interests on the 2015 NSPS and CPS.

MOG members have been heavily impacted by the 2015 NSPS and CPS. This overreaching initiative influenced market changes as the federal government was signaling its interest in utilization of the Clean Air Act to implement energy shifting away from coal. Accordingly, the coal-fired power industry was challenged to begin planning for the federally endorsed shift in energy generation options. Private financial institutions began to hesitate to invest in fossil-fuel assets, uncertain about the ability of such assets to continue in operation. South Tx. Electrical Coop. Amicus Brief at 12 -13 (*West Virginia v. EPA*) Market-based forces have already led to significant generation shifting in the power sector. 84 Fed. Reg. 32,520, 32,561 (July 2, 2019). EPA championed that the CPP had successfully forced significant and likely irreversible changes to the market. Pet. at 23.

C-5. The interpretation that it is appropriate to regulate emissions of an air pollutant from a source category only if those emissions contribute significantly to dangerous air pollution.

Section 111(b)(1)(A) provides, "[The Administrator] shall include a category of sources in such list if in his judgment it causes, or contributes significantly, to air pollution which may reasonably be anticipated to endanger public health or welfare." This statutory language stands for the proposition that for a source category to be established it is reasonably anticipated to cause or contribute significantly an endangerment to public health or welfare. MOG supports the proposal that the Administrator must make a significant contribution finding before issuing new GHG emissions standards for a new source category even if covered sources had previously been listed under a distinct category. Such an interpretation is consistent with section 111 that is designed to establish "standards of performance" for the best system of emission reduction for that source and the targeted pollutant. In the 2015 NSPS rulemaking docket, "EPA received comments on the 2015 NSPS stating that

CAA section 111 did not authorize regulation of GHGs from EGUs until the Agency first makes a finding that emissions of GHGs from EGUs contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. Such a finding is shorthanded here as a pollutant-specific significant contribution finding, and such air pollution is shorthanded here as dangerous air pollution." 90 Fed. Reg. 25760. MOG supports the reasonable conclusion that such technology review and BSER exercise is narrowly targeting a source category to a specific pollutant of concern. To read the statute as providing that any source category listed for a certain pollutant is fairly targeted for any other pollutant without identification of the endangerment is dismissive of the value of allowing transparent dialogue for how the agency arrived at that conclusion. For example, the explanation of the steps executed by EPA as described by the 2024 Efficient Generation TSD are not clear and do not portray an understanding of the EPA's actions. Specifically, the description presented does not describe how data from the 2009 Equipment Prices Study are used in lieu of the cost available describing steam side components as presented in the F-Class and H-Class cases of the 2023 NETL study. These are highly technical determinations that should engage all commenting parties with clarity.

C-6. The textual requirements of CAA section 111(b), relevant context from the remainder of CAA section 111, and relevant structural arguments regarding the CAA more generally, including statutory provisions not specifically discussed in this proposal.

Although to date, source category lists have been supplemented and expanded, it is reasonable to assess the possibility of elimination of a section 111 source category listing relevant to a particular pollutant for which it was previously deemed a significant contributor. If a section 111 source category were no longer a source of emissions that contribute significantly to dangerous air pollution, its regulation (BSER) would no longer be necessary nor required by section 111. Such an event would eliminate the regulated source category for that dangerous pollutant. It would not, however, impact the CAA section 202 endangerment finding for significant contribution of another pollutant. MOG supports EPA's conclusion that CAA section 111 requires a unique focused analysis of the listing of a source category for a particulate air pollutant.

C-7. The alternative interpretation of CAA section 111 to at least authorize the EPA to require a determination that an air pollutant significantly contributes to dangerous air pollution as a predicate to imposing standards of performance including with respect to whether the text of CAA section 111(b) confers sufficient *discretion on the EPA and whether additional provisions of CAA section 111 or the CAA more generally inform the scope of that discretion.*

MOG supports EPA's alternative interpretation of CAA section 111 as a reasoned implementation that ensures transparency by inviting public participation and comment to supplement the administrative agency's record to ensure promulgation of a defensible rule.

C-8. Whether the EPA erred in determining that it was not required to make a significant contribution finding in the 2015 NSPS or in not revisiting the issue in the CPS, and whether or not it would be appropriate to exercise its discretion here by requiring such a finding for GHG emissions from the fossil fuel-fired power plant source category.

Agency deference has been clarified with the *Loper Bright* decision. EPA's actions today are well founded in law concerning the proposed exercise of discretion. The key threshold is to ensure this proposal is based upon "reasoned decisionmaking" within the boundaries of the statute. This proposal invites vetting of the decisionmaking process and justification both in law and sound technology and science.

C-9. The change in interpretation from the 2015 NSPS, which allowed the EPA to regulate additional pollutants without ever having made a significant contribution finding for that pollutant, including any specific reliance interests relevant to the interpretation taken in the 2015 NSPS, as carried over into the CPS, and the relative strength of the rationale for these respective interpretations

EPA's proposal is based on the language of CAA section 111 and is distinguishable as a matter of law. This proposal, as opposed to actions in the 2015 NSPS, ensures a reasoned process for adding, only if lawful, new technology-based controls on sources that are significant contributors to the pollutant at issue, GHG emissions.

C-10. Whether and how the Supreme Court's recent decision in Loper Bright should inform the EPA's approach to interpreting CAA section 111 and selecting which interpretation better reflects the best reading of the statute.

Loper Bright explores the legal dilemma created by the *Chevro*n decision describing deference to agency decisions. The proposed emphasis upon a straight-forward reading of the text of the statute, combined with a transparent engagement of the public to provide opportunity for comment, will serve the key function of creating a thorough docket upon which the agency can base its final rule. Explanation of the validity of reasoning of the plain meaning of the text and how that justifies a departure from the 2015 NSPS will serve to demonstrate the final rule is a sensible exercise of judgment.

C-11. Whether its proposed interpretation of CAA section 111(b)(1)(A) as requiring a pollutant-specific significant contribution finding is necessary to avoid implicating the major questions doctrine as articulated by the Supreme Court in West Virginia. Specifically, whether the proposed interpretations in this section are necessary to prevent the Agency from improperly expanding its regulatory authority by determining that emissions of de minimis amounts of air pollutants, or non-harmful substances that may nevertheless be defined as air pollutants, should be regulated under CAA section 111.

The proposal is founded within the exercise of thoughtful decision-making on the scope of section 111 source category emissions relative to GHG air pollution. A legally thorough determination of significance and demonstrably available technology to define effective emission controls consistent with the Clean Air Act are clearly agency decisions based on delegated authority of Congress as opposed to a reach beyond the statute to set energy goals, public relations goals, or otherwise.

C-12. The strength of this interpretation and its application to GHG emissions by EGUs.

The emissions trends of GHGs across the world are increasing at a rate that will marginalize the ability of section 111 source category emissions controls to have any impact on significant contributions. (insert data)

C-13 ("Contribute Significantly"). The proposed determination that GHG emissions from the EGU source category do not "contribute significantly" to dangerous air pollution under CAA section 111(b)(1)(A).

As supported by the tables of domestic and global emissions provided within these comments, MOG agrees with EPA's conclusion that these sources are not section 111 "significant contributors" relative to the increasing emissions of other sectors and countries. Additionally, electric reliability derived from this sector serves to support public health and energy security.

C- 13 (Alternative Proposal) and C-14 The BSER determinations or standards of performance and related requirements for new and reconstructed intermediate load and low load fossil fuel-fired stationary combustion turbines, and The BSER determinations or standards of performance and related requirements for phase 1 for new and reconstructed base load fossil fuel-fired stationary combustion turbines.

MOG submits the above referenced Cichanowicz/Hein CT Report in full. See, Attachment B. The following summary or conclusions and comments are provided. A full review of the Report is requested.

The Cichanowicz/Hein CT Report provides comments to the alternative proposal (in response to C-13 and C-14) based on publicly available information, including the current rule issued May 4, 2024, and the associated rulemaking docket. A review of this material shows EPA's methodology for selecting Phase 1 standards for simple cycle and combined cycle CO2 emission rates is flawed, as is the economic evaluation upon which EPA relied to draw the line for base load units (which EPA assumes are always combined-cycle units) at an annual capacity factor of 40%.

First, in its rulemakings and related documents, EPA does not account for how combustion turbine design variants affect CO2 emission rate in the selection of an appropriate standard. Although EPA recognizes the different turbine designs – such as the E-, F-, H-, and J-Class and aeroderivative variants – the Agency does not consider such differences in selecting the CO2 emission rate. The inherent emission rate differences between these various designs can be estimated, initially, by comparing the performance specifications of the combustion turbine suppliers (i.e., thermal efficiency—and therefore CO2 emission rates—at high load under ISO conditions), adjusted to account for the impact of a real world environment – (e.g., non-ISO conditions: duty cycle; component degradation; ambient temperature; etc.). This analysis estimates both a "mean" and maximum" adjustment to apply to the high-load, ISO thermal efficiency specified by the supplier, and finds the median adjustments of 13-16% and maximum adjustments of approximately 22-24% comport with actual data measured for different turbine design categories.

Second, reviewing CO2 emissions obtained from the EPA Air Markets Program Data (AMD) and the specific CTs show that compliance with the present CO2 emission rates is not based on broadly available technology. Specifically, many simple cycle CTs operating between a 20% and 40% capacity factor are challenged to meet the emission rate of 1,170 lbs/MWh, as it is derived from an unrepresentative subset of units. Similarly, the present limit for CTs in combined cycle and at base load of 800 lbs/MWh (up to 900 lbs/MWh for small units) is not based on broad industry practice or available options. Specifically, for simple cycle CTs, the CO2 emission rate is based on the aeroderivative class, despite EPA intending this rate to be applicable to frame turbines designed to generate seven times more power. EPA cites three aeroderivative turbine designs by supplier and model – two reflecting the very best thermal performance by any simple-cycle CT – and effectively requires that all units in the population (even those seven times larger, with very different design) meet the same limit. There are many differences in the design attributes of aeroderivative turbines that distinguish them from large frame units that cannot be "scaled" to larger sizes. Most noteworthy, EPA does not recognize that aeroderivative units (which are typically small) can employ air compressors that create combustor inlet pressures up to 45 times that of the ambient air, elevating thermal efficiency by 2-3 percentage points above that achievable by frame turbines of intermediate generating capacity (150-350 MW). The broad population of simple cycle turbines cannot achieve such thermal performance. The net result of the current intermediate-load standard is largely to prohibit the construction of some aeroderivative CTs and most E-, F-, H-, and J-Class frame CTs (except perhaps the very largest H-Class units) for intermediate load duty.

Regarding combined cycle applications, EPA notes the actual CO2 emission rate of the population ranges from 720 to 920 lbs/MWh, averaging 810 lbs/MWh. EPA implements so-called "adjustments" to the CO2 emissions from these plants, correcting for different arrangement of combustion turbines and steam turbines. These adjustments range from accounting for a 1% advantage for a 2x1 arrangement compared to a 1x1 arrangement, the 1.4% advantage of wet versus dry cooling towers, and estimating any emissions increase observed at 40% load compared to full load. After these corrections, EPA then reverts to identifying the Dresden Plant in Ohio as a "best-performing" unit, emitting 770 lbs/MWh, enabled by the use of a wet cooling tower for which obtaining a permit in the present environment is challenging. EPA concludes the revised database and experience from Dresden justify a CO2 emission rate of 800 lbs/MWh rate. In doing so, EPA does not explain why any unit that does not use the specific design of the Dresden CTs, that is subject to different ambient or operating conditions than Dresden, and that is operated differently than Dresden (for example, experiencing more startup and shutdown cycles, more frequent load changes, or operation at a lower operating factor) can meet the selected standard.

Finally, EPA in the 2024 rulemaking employed a 2023 NETL study to create numerous reference cases to justify 40% capacity factor as the intermediate load threshold. An overarching concern is that such "static" studies do not always reflect the present marketplace and can be misleading. In other words, the results of EPA's own study could be very different in the future, if gas prices change, for example, or for a number of other reasons. Separate from that concern, EPA had to create four "new" reference cases to support its position by implementing numerous extrapolations and adjustments to the NETL reference cases, almost all of which introduce significant error. These "new" reference cases created by EPA compare the levelized cost of electricity (LCOE) from a simple and combined cycle unit. Results show these units generate equivalent LCOE at 40% capacity factor – but just barely, and likely not supported by the margin of error, as differences range from negligible to 2%. Based on the trends in LCOE extrapolated from the NETL study, EPA established a yearly capacity factor of 40% as the cutoff between intermediate load and base load categories, in effect mandating that any new simple-cycle CT is prohibited from operating at a capacity factor higher than 40% unless CCS is installed and operated starting in 2032.

This analysis presents an alternative approach to analyzing the appropriate capacity factor for intermediate loads, using a more recent Energy Information Administration (EIA) study. This approach requires only a modest extrapolation to create one "new" reference case. The sole extrapolation scales capital cost and operating variables of a 650 MW combined cycle to 450 MW – well within the range of generally accepted scaling criteria. No other adjustments or extrapolations are required. These EIA-derived results show that for conditions of unit lifetime, scaling factor for capital cost, and natural gas price only slightly different from EPA's but equally reasonable, simple cycle and combined units generate at equal LCOE at greater than 50% capacity factor. Consequently, the use of 40% capacity factor as the threshold for practically requiring a combined-cycle configuration is not justified.

The Cichanowicz/Hein CT Report includes four sections as follows. Section 2 presents results of calculations using suppliers-specified heat rates, adjusted using adjustments by an industry observer that reflect real-world duty. Section 3 presents actual results from the AMPD as evaluated by EPA, and independently by this study. Section 4 identifies how EPA established the basis for the proposed CO2 emission rate limits for simple and combined cycle CTs. Section 5 critiques EPA's economic study used to justify the 40% capacity factor threshold for base load operations and performance standards (i.e., simple-cycle prohibition), and introduces an alternative approach.

C-15. The position that CPS included an incorrect accounting for the costs of control as the EPA should not be considering tax credits when determining cost of control.

Previous efforts to rely on the expenditure of public monies to defray costs create a message that lacks transparency and clarity of the financial impact of the rule. The public should be clearly informed of the actual total costs that are being incurred and how those costs are being paid as the result of the emissions reductions required by the rule.

C-16. The arguments for repealing the 90 percent CCS-based requirements of the emission guidelines pertaining to long¬term coal-fired steam generating units.

MOG supports the repeal of the CCS-based requirements as such requirements are not available for implementation on many legal and technical levels.

C-17. The proposed conclusion that 90 percent CCS is not an adequately demonstrated system of emission reduction.

MOG agrees with the conclusion that there is not available adequate demonstrated CCS that can serve as a system of emission reduction. MOG members are not aware of any facts that support the conclusion of adequate demonstration.

C-18. The proposal that the performance of the CO2 capture system at Boundary Dam Unit 3 is not a sufficient basis for determining that 90 percent CCS is adequately demonstrated for coal-fired steam generating units

The Boundary Dam Unit 3 illustration serves to demonstrate that CCS is not adequately demonstrated technology.

C-19. The status and performance of CCS projects and technologies more generally, especially on projects that inform the question of whether 90 percent CCS is adequately demonstrated

MOG is unaware of any specific projects that demonstrate 90 percent CCS application.

C-20. The proposed conclusions regarding the impacts of startup and of variability more generally on CCS performance, as well as on methods to control process parameters (pressure, velocity, etc.) and capture efficiencies under startup and variable load, and what differences in those methods exist where the CO2 capture system processes all or part of the flue gas.

MOG has assessed available data on CCS performance/operation and supports the conclusion that CCS presents numerous operational impediments that impact its ability to achieve 90% capture.

C-21. The proposed conclusion that the cost of 90 percent CCS for long-term coal-fired steam generating units is not reasonable, including on any considerations related to taking the IRC section 45Q tax credit into account when calculating the costs of CCS in the context of a BSER analysis.

The full assessment of costs represented by 90 percent CCS has yet to be developed and EPA's determination that CCS for long-term coal fired steam EGUs is not reasonable is well-founded. Reliance upon public tax dollars to underwrite CCS as a means to find it a reasonable regulatory option is neither transparent, nor well-reasoned.

C-22. The costs of CCS for existing coal-fired steam generating units, including on the interplay of design capture efficiency, actual capture efficiency, and cost effectiveness.

MOG members are very familiar with USDOE funded research of CCS. MOG is unaware of any studies or demonstration projects that predict with clarity capture efficiency or cost effectiveness.

C-23. The proposed determination that, because it is unlikely that the infrastructure for CCS can be deployed by the January 1, 2032, compliance date, the degree of emission limitation is not achievable for long-term coal-fired steam generating units.

Based on the fact that there are many statutory and regulatory gaps concerning infrastructure, eminent domain, and comprehensive regulatory programs, it is reasonable to conclude that the CCS mandate is not achievable by the January 1, 2032, compliance date.

C-24. The proposed repeal of the 40 percent co-firing BSER.

The co-firing BSER is improperly based upon the conclusion that units and facilities are uniform in function and 40% is achievable. Additionally, co-firing suggests fuel switching and energy policy which are not within the scope of the Clean Air Act. Fuel switching raises the question of whether energy policy is a major question for which Congress did not grant authority found in the Clean Air Act.

C-25. Considerations related to the supply of and demand for natural gas, and on how the diversion of natural gas to coal-fired steam generating units would impact the energy system.

The demand for natural gas through many varied influences clearly impacts the energy system. The energy system includes electric power generation for use by residents, manufacturing, power generation, data centers, etc. It is legally and politically prudent for EPA to manage its impact on the energy system within the bounds of its federal statutory authorizations, such as the Clean Air Act. Accordingly, a well-reasoned proposal must focus upon objective legal and technical criteria when implementing section 111.

C-26. The relative efficiency of co-firing natural gas versus using it in a combustion turbine to generate electricity.

First, it is accepted that the introduction of natural gas for co-firing with coal does not significantly affect net plant heat rate. The higher moisture content of natural gas may compromise boiler thermal efficiency, but as cited by EPA in the 2023 GH TSD, the use of natural gas co-firing to 40% could be reasonably assumed to lower thermal efficiency by 1%.

The average U.S. coal plant in 2023 operated at approximately 33% thermal efficiency; approximately the same thermal efficiency which natural gas is utilized. Thus, 33% is assumed as a valid estimate for the efficiency of natural gas use as co-fired fuel.

Second, the thermal efficiency of natural gas used in simple cycle combustion turbines is presented in the report in Figure 4-2. This chart shows natural gas is utilized in a simple cycle turbine at a thermal efficiency basis (higher heating value) to be 35 to 38%, depending on the specific turbine (aeroderivative or frame) and the generating capacity.

Third, for combined cycle, Table 5-2 of the Cichanowicz/Hein CT Report, Attachment B, reports that Case 6 of the EIA study cites an H-Class a gross heat rate of 6,226 Btu/kWh, or equivalent to 54% thermal efficiency.

In summary, the use of natural gas as co-firing with coal is the least efficient means by which to utilize this fuel.

C-28. The proposed conclusion that 40 percent natural gas co-firing cannot be the BSER for a coal-fired steam generating units because it constitutes generation shifting.

To determine the BSER, the EPA first identifies the "system[s] of emission reduction" that are "adequately demonstrated," and then determines the "best" of those adequately demonstrated systems, "taking into account" factors including "cost," "nonair quality health and environmental impact," and "energy requirements." The EPA then derives from that system an "achievable" "degree of emission limitation." The EPA must then, under CAA section 111(b)(1)(B), promulgate "standard[s] for emissions"—the NSPS—that reflect that level of stringency. The proposal that 40 percent natural gas co-firing cannot be BSER is well-reasoned based upon the fact that the cost and natural gas diversion combine to render the concept as ineligible for BSER. The best system of emission reduction is not shifting generation heavily influenced by cost.

C-29. The determination that a degree of emission limitation based on 40 percent natural gas co-firing is not achievable because it is unlikely that the pipeline infrastructure necessary can be deployed by the compliance date of January 1, 2030

Pipeline development has been significantly delayed due to permitting administrative delays and litigation. It is reasonable to conclude that any industry-wide prediction of pipeline availability is not possible.

C-30. Considerations related to the achievability of the presumptive standard of performance for medium-term coal-fired steam generating EGUs in the CPS.

As explored in detail in the attached Cichanowicz/Hein CCUS report, CCUS is not demonstrated therefore the presumptive standard is not achievable.

C-31. The arguments for repealing the requirements of the emission guidelines pertaining to natural gas- and oil-fired steam generating units.

MOG's comments support robust assessment of the achievability of the emissions guidelines to natural gas- and oil-fired steam generating units. MOGs comments provide examples of facts that serve to inform EPA of arbitrary and capricious regulatory actions.

C-32. The rationale for repealing the CCS-based standards of performance for coal-fired steam generating units undertaking a large modification.

The business of finance and power generation find the risk of undertaking the extended permitting application process for a major modification, capital expenditures and threat of federal regulation and funding for CCS development renders it an unrealistic goal at this time. CCS-based standards should be repealed as not well-reasoned.

C-33. The arguments for the proposed repeal of the phase 2 standards for base load combustion turbine EGUs.

As noted above, MOG supports repeal of the phase 2 new base load combustion turbine EGUs, as justified by the failure of the agency to finalize a specific determination of significant contribution to dangerous air pollution, that cost-effective control measures are not reasonably available, and that public health and welfare are promoted through energy dominance and independence.

C-34. The proposed conclusion that 90 percent CCS is not an adequately demonstrated system of emission reduction for base load stationary combustion turbine EGUs.

The Cichanowicz/Hein CCUS Report, Attachment A, sets forth in detail the case for the conclusion that CCS is not adequately demonstrated system of emission reduction for base load stationary combustion turbine EGUS.

C-37. The proposed conclusion that the cost of 90 percent CCS for new base load combustion turbines is not reasonable, including on any considerations related to taking the IRC section 45Q tax credit into account when calculating the costs of CCS in the context of a BSER analysis.

As noted above, MOG does not support a technology cost analysis that incorporates tax credits. Such a shift of costs does not eliminate the financial burden.

C-38. The costs of CCS, including on the interplay of design capture efficiency, actual capture efficiency, and cost effectiveness.

The Cichanowicz/Hein CCUS Report, Attachment A, sets forth the inability to adequately calculate the costs of CCUS.

C-39. The proposed determination that, because it is unlikely that the infrastructure for CCS can be deployed by the January 1, 2032, compliance date, the phase 2 standards of performance are not achievable for new base load combustion turbines.

MOG is unaware of any current or impending developments that would support a realistic conclusion that CCS infrastructure would be deployed by 2032 for new base load combustion turbines and supports the proposed determination of infeasibility.

CONCLUSION

For all of the aforementioned reasons, MOG urges EPA to finalize its Primary Proposal and to repeal all of the GHG requirements set forth in 40 CFR part 60, subparts TTTT, TTTTa and UUUUb.

Should EPA not finalize its Primary Proposal, MOG urges that EPA expeditiously finalize its Alternative Proposal to repeal a portion of the 40 CFR part 60, subparts TTTT, TTTTa and UUUUb requirements and to immediately initiate a rulemaking to reconsider the remaining portions of those subparts and to provide near-term relief from the implementation of those requirements.

Very truly yours,

Kathy G. Beckett

Kathy G. Beckett

Counsel for the Midwest Ozone Group