Andy Beshear
GOVERNOR

ENERGY AND ENVIRONMENT CABINET
DEPARTMENT FOR ENVIRONMENTAL PROTECTION
300 Sower Boulevard
Frankfort, Kentucky 40601
Phone: (502) 564-2150
Fax: 502-564-4245

Rebecca Goodman
SECRETARY

Anthony R. Hatton
COMMISSIONER

August 8, 2023

ATTN: DOCKET ID. NO. EPA-HQ EPA-HQ-OAR-2023-0072; FRL-8536-02-OAR
Via Electronic Submission to http://www.regulations.gov

RE: Docket ID. No. EPA-HQ-OAR-2023-0072; FRL-8536-02-OAR
Proposed Rulemaking for *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*

Dear Docket Manager:

The Kentucky Division for Air Quality (Division), on behalf of the Kentucky Energy and Environment Cabinet (Cabinet), appreciates the opportunity to provide the attached comments on the U.S. Environmental Protection Agency's (EPA) proposed rulemaking for *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* published in the Federal Register[1] on May 23, 2023.

The Division recommends EPA withdraw the proposed rule and re-propose standards that use a Best System of Emission Reduction (BSER) that is adequately demonstrated. In this re-proposal, EPA should also carefully consider the cumulative impact that rulemakings affecting the power sector have on grid reliability and cost to ratepayers.

The Division appreciates EPA’s consideration of these comments. If you have questions or comments, please contact me at, Michael.Kennedy@ky.gov, at your convenience.

Sincerely,

Michael Kennedy

Michael Kennedy, P.E., Director
Kentucky Division for Air Quality

Attachments

[1] 88 Fed. Reg. 33,240.

KY DAQ Comments on the U.S. Environmental Protection Agency's (EPA) Proposed Rulemaking for *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*

I. CCS and Hydrogen is inappropriate as BSER

EPA mistakenly concludes in this proposed rulemaking that Carbon Capture and Sequestration (CCS) and hydrogen fuel each represent the Best System of Emission Reduction (BSER) for certain new and existing fossil fuel-fired electric generating units (EGUs) because they are not adequately demonstrated.

EPA should not deem CCS and hydrogen fuel BSER under this proposed rulemaking. CCS is not adequately demonstrated as BSER. It is currently only used at a handful of facilities, only one of which is in the United States. CCS only exists due to federal funding that may not be provided to other facilities. Current CCS projects at coal-fired EGUs cannot comply with the proposed standard long-term. Therefore, it is unreasonable to conclude it represents BSER for the applicable units as stated in this proposal. The Cabinet assisted in funding a small CCS demonstration project at an EGU in Kentucky. The cost to operate and maintain the project proved to be exorbitant compared to the amount of CO_2 captured and making full scale deployment unaffordable and unrealistic.

Hydrogen fuel cannot be BSER as the current infrastructure is lacking, including unavailability of sufficient hydrogen pipelines infrastructure to support the proposed rule. Speculation on what could be in the future is irrelevant to the requirements within the proposal. It is important to note that allocating money in the Inflation Reduction Act of 2022 (IRA) does not mean it is actually what will be approved or when it will be built. It is unknown if funding recipients will know if they are approved for funding before a State plan is due. In addition, the Inflation Reduction Act of 2022 (IRA) allocated funding is for all hydrogen, not just “low Greenhouse Gas (GHG)” hydrogen, which could lead to further reductions in available funding. As an example, the Energy Policy Act of 2005 also allocated funding for hydrogen infrastructure, but to date, the infrastructure has not been put in place.

Additional problems arise with the IRA definition of low GHG hydrogen. The IRA definition of low GHG does not meet the standard of what EPA is requiring in the proposed rulemaking. EPA should define low GHG hydrogen prior to issuing the Final Rule here. However, creating this definition may not be appropriate in a 111(d) rulemaking.

Underestimated EGU retirements by EPA could lead to miscalculations for the amount of new infrastructure actually needed for natural gas. For example, the requirement for co-firing natural gas for certain subcategories of units requires additional natural gas pipeline infrastructure. It should not be assumed to be in place prior to State plan submittal or prior to a compliance deadline.

Finally, there are several environmental justice concerns that arise when siting new hydrogen pipelines or CCS facilities. In the Agency's pre-proposal outreach, some environmental justice (EJ) organizations and community representatives raised strongly held concerns about the potential health, environmental, and safety impacts of CCS.[1] These problems remain. In fact, the White House Environmental Justice Advisory Council is currently reviewing the EJ impacts of CCS. In the final rule, EPA should reconsider whether CCS is an appropriate BSER, taking into account impacts to already overburdened EJ communities. These concerns further reduce the likelihood of timely availability of these facilities.

II. Standard

The Division supports the standard for imminent and near-term retiring units being Business As Usual (BAU). The Division does not support Heat Rate Improvements (HRI) as a requirement for these units. Any costs associated with any standard for imminent and near-term retiring units would lead to increased costs for ratepayers. The small benefits associated with HRI is inequitable for the cost incurred by ratepayers. Finalizing the standard as BAU for these facilities reduces any need for any Remaining Useful Life and Other Factors (RULOF) demonstrations from states or facilities.

The Division questions whether EPA is taking an arbitrary position in requiring a standard for existing coal units operating after 2040 to have an 88.4% reduction in CO_2 emissions, when the standard under 40 CFR Part 60, Subpart TTTT is 1,400 lbs/MWh. The Clean Air Act (CAA) clearly acknowledges the differences for standards between new sources and existing sources, even allowing for the use of RULOF for existing sources to evaluate existing source standards. Proposing a more stringent existing source standard in an emissions guideline conflicts with Section 111 of the CAA.

III. Fuel-switching and "Beyond the Fence Line"

Fuel switching

The proposed rule seeks to mandate coal and natural gas EGUs to "co-fire" with other types of energy, including a requirement for base load natural gas turbines to co-fire with 30-percent clean hydrogen in 2032. The applicable EGUs would be required to ramp-up to 96% co-firing of clean hydrogen by 2038 – fundamentally changing the fuel source. This proposal conflicts with the Supreme Court ruling in *West Virginia v. EPA*, which held that Congress never granted EPA the authority to require generation shifting under the CAA. Generation shifting would occur even at 30% co-firing. For coal-fired power plants that continue to operate beyond 2032, but plan to close before 2040, the rule requires 40-percent natural gas co-firing.

Beyond the fence-line

The proposed rule establishes CCS and hydrogen co-firing as BSER. As previously mentioned, neither is adequately demonstrated. The requirements of the proposed rule to include contracts and infrastructure built as part of the State plan is inappropriate. The Division does not have the

[1] 88 Fed. Reg. 33,247.

expertise in permitting or the resources available to make determinations about whether these contracts and timelines are appropriate. Any approval of this type of information as submitted for the State plan would be arbitrary and capricious by the Division. The need for this infrastructure is beyond the fence line of the EGU and is not controlled by the EGU. Additionally, it is inappropriate for the Division to put emission standards into permits based on infrastructure that is speculative and yet to be constructed. Even for the purposes of natural gas co-firing, the installation of new NG pipeline is a lengthy process, regularly faced with delays due to the vast expanse of land the pipeline must cover. Whether pipeline infrastructure is built for the purposes of NG, hydrogen, or CCS is irrelevant, the timing and capital required for completion are beyond the control of the EGU.

Underestimation of Retirements

This proposed rule underestimates the number of retired units and MW of electricity that will need to be replaced. EPA only considered the ramifications of this particular proposal in estimating retirements, but the cumulative impacts of compliance costs from this proposal, the Good Neighbor FIP, proposed MATS rule, Regional Haze, and the CCR and ELG rules should be considered.

This proposal does not establish a standard for simple cycle natural gas units. As such, it incentivizes the use of these units. Unfortunately, these units are less efficient and have higher emission rates of pollutants than some of the units that are regulated by this proposal. EPA is in incentivizing the use of simple cycle units that emit more pollution.

IV. Issues with State Plans

EPA is directing the state submit State plans that contain standards of performance that are consistent with the emission guidelines.[2] The EPA is proposing a State plan submission date that is 24 months after the publication of final emission guidelines and proposing a compliance date for a portion of affected EGUs as January 1, 2030.[3] Two years is not sufficient time for the Division to prepare and submit a State plan that would meet the regulatory requirements. State plans require collaboration with multiple stakeholders and a lengthy approval process by the State Legislature. Furthermore, additional time will be required to complete the substantial meaningful engagement procedures, as proposed in the new subpart Ba.

The EPA is proposing to allow states to include trading or averaging in State plans so long as the state demonstrates equivalent emissions reductions. This proposal discusses considerations related to the appropriateness of including such compliance flexibilities[4]. This would further lengthen the process needed to draft and submit a State plan. Additionally, given the large number of sources which will be investing in the proposed control methods, timing

[2] 88 Fed. Reg. 33,243.
[3] 88 Fed. Reg. 33,403.
[4] 88 Fed. Reg. 33,393.

considerations must be given to the availability of materials, installation/construction, worker availability, engineering services and potential supply chain issues.

The EPA seeks comment on implementation of the proposed subpart Ba requirements pertaining to determining a source-specific BSER and calculating a less stringent standard for sources invoking RULOF under these emission guidelines.[5] The Division cannot adequately comment on a proposed rulemaking that may be impacted by a separate proposed rulemaking that has yet to be finalized. The EPA should finalize subpart Ba before including the requirements preemptively in a new proposal, especially one that has the potential to affect the entire electric grid of the United States.

The EPA acknowledges that there may be instances in which a change in EGU subcategory will be necessary. For certain affected EGUs that are switching subcategories, the EPA proposes to require that the State include in its State plan revision documentation for the affected EGU's submission to the relevant Regional Transmission Organization (RTO) or balancing authority of the new date it intends to permanently cease operations, any responses from and studies conducted by the RTO or balancing authority addressing reliability and any other considerations related to ceasing operations, any filings with the SEC or notices to investors in which the plans for the EGU are mentioned, any integrated resource plan, and any other relevant information in support of the new date.[6] All these steps, including requiring publication of this information to the Carbon Pollution Standards for EGUs website, are beyond what has historically been required in State plans and EPA has not demonstrated that these steps add value to the process. The State should be able to rely on information provided on the retirement by the EGU itself, as it does in the normal application process. In addition, multiple plan revisions will become an unfunded mandate to states and EPA must work closely with states to make sure sufficient timelines are given so that there is meaningful participation and unintended consequences do not result. The continued increase in actions demanded by EPA in meeting requirements puts a significant strain on the already stretched budgets of the state agencies.

V. Strict Compliance Timeline and Pathways

The EPA's proposed timeline is too strict to allow for compliance. The Division does not support any shorter timelines than what are proposed in the rule.

<u>Infrastructure</u>

Infrastructure is currently inadequate to support natural gas co-firing, hydrogen co-firing, or any CO_2 pipeline needed. The proposed rule establishes a 24-month deadline for states to submit State plans, but it is unlikely that any of the infrastructure needed for compliance will be in place by that time. Facilities that apply for IRA funding for any hydrogen infrastructure or co-firing

[5] 88 Fed. Reg. 33.386.
[6] 88 Fed. Reg. 33.404.

may not even know whether their funding requests are approved prior to State plan submittal deadlines. It is unclear how EPA expects an EGU to have a contract in place for the purchase of hydrogen or natural gas if the infrastructure is not in place to deliver the fuel to the source.

There are currently no Class VI wells in the state of Kentucky which could be used for CCS. The state does not have primacy over the Class VI well program. It is unlikely that any well could be permitted in the state prior to 2035. EPA should consider the permitting implications of actions outside the control of the EGU for the use of CCS.

Electric transmission

The proposed rule will lead to retirements of the existing fossil-fuel fleet. However, EPA has not considered the necessary changes to the transmission grid to add new sources of electric generation.

Grid reliability

Requiring EGUs to run less often does not lower the demand for electricity, regardless of whether the EPA has chosen arbitrary limits on how often EGUs can run. It does not appear that EPA has considered how the needed infrastructure and grid transmission changes will impact reliability or grid demand.

The Department of Energy (DOE) State Energy Risk Profile examines the relative magnitude of the risks that the state of Kentucky's energy infrastructure routinely encounters in comparison with the probable impacts. The natural hazard that caused the greatest overall property loss in Kentucky between 2009 and 2019 was Winter Storms & Extreme Cold at $33 million per year (7th leading cause nationwide at $418 million per year). Kentucky had 305 Major Disaster Declarations, 0 Emergency Declarations, and 5 Fire Management Assistance Declarations for 11 events between 2013 and 2019.

Most recently, Winter Storm Elliott's impact to Kentucky's electric infrastructure resulted in unprecedented generation failure along with the first ever rotating outages in Louisville Gas and Electric and Kentucky Utilities territories along with areas served in Kentucky by the Tennessee Valley Authority. TVA's After-Action Report[7] from the December 2022 event concluded that "In total, 38 of TVA's 232 generating units were negatively impacted . . . TVA's nuclear and hydro assets were not affected by the extreme weather due to their plant design and operated without issue supporting energy demand during the event." Strategic considerations from the TVA report include to continue assessing risks in capacity planning including implications of extreme weather on capacity planning and operational preparation and fuel resiliency and redundancy.

[7] https://bloximages.newyork1.vip.townnews.com/local3news.com/content/tncms/assets/v3/editorial/4/3e/43e4b436-eb67-11ed-a87a-530b1c4c2bd9/645537f5cd9d7.pdf.pdf

Kentucky is also served by PJM member utilities, which also experienced tight operational conditions during the event. PJM similarly concluded that "Elliott's rapidly falling temperatures coincided with a holiday weekend that combined to produce unprecedented demand for December. This was further complicated by unexpectedly high resource unavailability and/or failures to perform . . . At one point, almost a quarter of the generation capacity – 47,000 MW – was on forced outages." When examined over the entire generation fleet, gas generators accounted for 70% of the outages on Dec. 24.[8]

More specifically, PJM has is conducted a series of activities around ensuring a reliable energy transition.[9]

> *Phase 3 of PJM's ongoing study of impacts associated with the energy transition explores the pace of resource retirements and replacements through 2030 and highlights potential reliability risks to meeting growing electricity demand. The analysis shows that 40 GW of existing generation are at risk of retirement. The study's projections indicate that the current pace of new entry would be insufficient to keep up with expected retirements and demand growth by 2030.*

A generation fleet that is comprised of baseload, fuel assured resources mitigates the threat to frequent and long-term power disruptions. The pace of a generation fleet's transition must be done at rate that ensures baseload, fuel assured resourced remain online to provide balancing grid services and to meet unexpected peak demands. Technology that is unproven or not commercially viable reduces the nation's capacity to respond and provide reliable electricity. This has been documented by the North American Electric Reliability Corporation (NERC) in their reliability assessments.[10]

> "As new resources are introduced and older traditional generators retire, careful attention must be paid to power system and resource mix reliability attributes. Within the 10-year horizon, over 88 GW of generating capacity is confirmed for retirement through regional transmission planning and integrated processes. Effective regional transmission and integrated resource planning processes are the key to managing the retirement of older nuclear, coal-fired, and natural gas generators in a manner that prevents energy risks or the loss of necessary sources of system inertia and frequency stabilization that are essential for a reliable grid….. The changing composition of the North American resource mix calls for more robust planning approaches to ensure adequate essential reliability services.9 Retiring conventional generation is being replaced with large amounts of wind and solar; planning considerations must adapt with more attention to essential reliability services"

[8] https://pjm.com/-/media/library/reports-notices/special-reports/2023/20230717-winter-storm-elliott-event-analysis-and-recommendation-report.ashx
[9] https://www.pjm.com/about-pjm/ensuring-a-reliable-energy-transition
https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2022.pdf [10]

NERC concluded that the energy and capacity risks identified in this assessment underscore the need for reliability to be a top priority for the resource and system planning community of stakeholders and the importance of manage the pace of generator retirements until solutions are in place that can continue to meet energy needs and provide essential reliability services. Further, at a recent Natural Resource and Energy Interim Joint Committee meeting, Haque (VP of state and member services at PJM) stated, "Later on into this decade, we are concerned about a supply crunch – concerned about resources leaving the system too quickly and new resources not finding their way onto the system at a rate to replace those resources leaving the system."[11] This rulemaking significantly impacts the ability to manage the pace of that transition and compromised reliability efforts.

The push for the electrification is going to increase the MW needed from the grid. As the grid becomes increasingly stretched as baseload power is diminished, it is unclear how additional MW will be generated.

The Division believes EPA should do a cumulative impact analysis of rules impacting the power sector, including the ELG, CCR, MATS, Good Neighbor, Regional Haze, and EV rulemakings. This larger analysis will allow for a more accurate accounting of sources that are going to be retiring and the stability of the electric grid.

Due to the potential for ongoing grid reliability issues, the Division supports the system emergency provisions of the proposed rule. The Division does not support having to choose between meeting requirements of the CAA in a permit or providing electricity as required by the Federal Energy Regulatory Commission.

VI. Applicability Issues

EPA needs to address and correct multiple applicability issues.

EPA should not use capacity factor as a criteria for determining applicability of the emission guidelines to a specific unit. The capacity factor of a natural gas unit can fluctuate. It is impossible to anticipate for whether a unit is going to be "in" or "out" of the state plan as its capacity factor fluctuates between 48% and 52%. The practical aspects of how to enforce an "in" and "out" based upon capacity factor is unmanageable.

Electric sales should not be used as a determination of exemption from the rule as these are not under the control of the EGU owner/operator.

The proposed regulatory text states:

> "EGUs that are excluded from being affected EGUs are:

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[11] See - Aug 3 2023 PJM Haque PowerPoint.pdf (ky.gov); "Questions abound from legislators during energy-related meeting" Legislative News Release (ky.gov)

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

However, the EPA issued a Memo "Applicability of Emission Guidelines to Existing Stationary Combustion Turbines: FAQs Memo"[12] that explains methods to adjust both the generating capacity and the annual capacity factor. Regulatory text must include language that clearly explains that there are adjustments to the electric generating capacity so that 250 MW nameplate capacity can be turned into 325 MW in some circumstances.

Fuel-switching by requiring co-firing of natural gas (for coal units), or hydrogen, changes the characteristic of the unit. At 96% co-firing of hydrogen, a unit would be exempt from being an affected unit because the fossil fuel would be less than 10% of the fuel source. This is redefining the source, but still requiring the source to remain in the existing source standards.

VII. Meaningful Comment and Logical Outgrowth

States and the regulated community lack the ability to provide full meaningful comment due to the breadth of multiple, simultaneous rulemakings affecting similar industry sectors.

Multiple agencies and stakeholders will need to collaborate to fully evaluate the impacts of the proposed rule, including its five separate proposed actions: 1) revised New Source Performance Standards (NSPS) GHG emissions from new fossil fuel-fired stationary combustion turbine EGUs; 2) revised NSPS for GHG emissions from modified fossil-fuel fired steam generating units; 3) emission guidelines (EG) for GHG emissions from existing fossil fuel-fired steam generating EGUs; 4) EG for GHG emissions from existing stationary combustion turbines; and 5) repeal of the Affordable Clean Energy (ACE) Rule.[13] In addition, this robust proposal overlaps with other significant and recently proposed rulemakings impacting the power sector, including the proposed Steam Electric Power Generating Effluent Limitations Guidelines (ELG), Legacy Coal Combustion Residual (CCR) Surface Impoundments and CCR Management Units rulemaking, "Good Neighbor" Federal Implementation Plan (FIP), and the Mercury and Air Toxics (MATS) Risk and Technology Review (RTR), making this review even more complex.

Furthermore, the EPA seeking comment on any unit not given a standard in the proposal, or providing a range for standards, or contemplating suggested threshold by certain commenters of thresholds as low as 25 MW is inappropriate for a proposed rulemaking and deprives the public of meaningful comment. The EPA should withdraw this proposal and re-propose separate rulemakings and/or requests for information so that the public, states, and regulated industry can provide adequate and necessary comment. If the EPA makes significant changes to the

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[12] Applicability of Emission Guidelines to Existing Stationary Combustion Turbines.pdf (epa.gov)
[13] 88 Fed. Reg. 33,240.

proposal as a result of public comment, the EPA should re-propose to allow for meaningful comment as required by the Administrative Procedures Act.

VIII. Cost Considerations

The EPA has inaccurately accounted for costs and benefits for this proposed rulemaking. In recent months, the EPA has issued proposed and final rulemakings that greatly impact the power sector in the Commonwealth and the United States. These rulemakings have overlapping deadlines, requirements, and retirement dates. With multiple rulemakings and compliance deadlines looming, EPA runs the risk of inaccurately accounting for the costs and benefits of this proposed rule. Cost considerations should anticipate the cumulative impact of other rulemakings will force either the retirement of coal- and oil-fired EGUs, or a conversion to alternative fuel sources. There are costs, and potentially stranded assets, that will result from these decisions. The associated costs of compliance with these rulemakings will be passed along as increases to ratepayers.