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American Coalition for Clean Coal Electricity Comments on EPA's Proposed Rule to Revise CO_2 NSPS

The American Coalition for Clean Coal Electricity (ACCCE) submits the following comments to the Environmental Protection Agency (EPA or Agency) on the proposed rule to revise the current new source performance standards (NSPS) for limiting carbon dioxide (CO_2) emissions from new, modified and reconstructed coal-fueled power plants (Proposed Rule or Proposal).[1] EPA has proposed to make changes to the current NSPS Rule that EPA adopted in October 2015 for limiting CO_2 emissions from coal-fueled power plants (2015 NSPS Rule or 2015 Rule).[2] These changes include amending EPA's prior determination that partial carbon capture and sequestration (CCS) is the "best system of emission reduction" (BSER) for new coal-fueled power plants and instead determining that the BSER for such plants is the most efficient demonstrated steam cycle in combination with best operating practices. For the reasons discussed below, ACCCE supports EPA's proposed revision to the BSER determination.

ACCCE is a non-profit organization that advocates at the federal and state levels on behalf of coal-fueled electricity and the coal fleet. ACCCE's members include electricity generators, coal producers, railroads, barge operators and equipment manufacturers.[3] ACCCE previously submitted comments to EPA opposing its proposal to establish specific CO_2 performance standards in the 2015 Rule. Our comments submitted on the 2015 Rule are incorporated herein by reference. In addition, ACCCE is a member of the Utility Air Regulatory Group (UARG) and incorporates by reference the comments UARG is submitting on the Proposed Rule.

Overview of ACCCE comments

The proposed revisions to the 2015 Rule are necessary to assure that the electricity grid is able to deliver affordable and reliable electricity 24/7. The need to deploy new coal-fueled generating capacity is taking on an increasing importance because of the retirement of substantial amounts of coal-fueled generating capacity and the resulting loss of fuel diversity, reliability and resilience attributes, and fuel security provided by the coal fleet.[4] (Currently, some 40 percent of the coal fleet has retired or announced plans to retire.[5]) While the decision to construct new coal-fueled generating capacity will depend on a number of factors, it is unwise for EPA to impose requirements that would prevent the deployment of new coal-fueled power plants which may be needed in the future.

Although a promising technology for controlling CO_2 emissions from power plants, none of the CCS technologies now under development has yet been demonstrated for reliable full-scale operation at coal-fueled electric generating units (EGUs).[6] Therefore, ACCCE agrees with EPA's proposal to select as BSER the high efficiency supercritical boiler design for large coal units, as well as the most efficient subcritical boiler designs for small EGUs. These generating technologies have been commercially demonstrated across the entire coal fleet for many years under a wide range of operating conditions at reasonable costs, and they will achieve meaningful reductions in CO_2 emissions from new coal-fueled generating units. ACCCE also supports the BSER determination based on high efficiency generating technologies for reconstructed and modified coal plants.

NSPS should not de facto ban new coal-fueled EGUs.

One of many problems with the 2015 NSPS is that it prevents the deployment of new coal-fueled electric generating capacity in the future. Since 2010, the electric power sector has retired or announced plans to retire almost 121,000 megawatts (MW) of coal-fueled electric generating capacity.[7] This retiring capacity amounts to 40 percent of the nation's coal fleet and poses a growing threat to the resilience and reliability of the electricity grid. At the same time the coal fleet is declining (in large part due to past EPA policies), the grid is becoming increasingly reliant on natural gas and renewable energy. Over the past 13 years more than 160,000 MW of gas-fired generation, wind and solar have been added to the grid. None of these electricity sources provides as much fuel security as the coal fleet.

As EPA noted in the preamble to the Proposed Rule, there is significant "value in maintaining the ability to develop non-natural gas-fired base load generation," such as fuel-secure sources of electricity that have "the ability to store significant quantities of fuel onsite."[8] Fuel security enables the grid to withstand, operate through, and recover quickly from major disturbances (such as extreme weather events or attacks on energy infrastructure) that could have serious, if not catastrophic, consequences for the delivery of reliable and affordable electricity.[9] Therefore, creating barriers to the deployment of new fuel-secure coal-fueled EGUs amounts to poor energy policy.

Partial CCS is not BSER because it is not adequately demonstrated.

ACCCE agrees with EPA's proposal to revise its prior determination that partial CCS is BSER based on new information and updated analyses indicating very large costs and major technical barriers to deploying CCS. These economic and technical constraints lead to the conclusion that partial CCS is not "adequately demonstrated."

CCS is an emerging technology that EPA cannot consider in setting CO_2 performance standards under CAA section 111. Although a few first of a kind (FOAK) applications of post-combustion carbon capture systems are currently operating, these demonstration projects indicate that CCS technologies are technically feasible but do not meet the statutory standard that the technologies are "adequately demonstrated."

To date, commercial application of CCS technologies on coal-fueled EGUs has been limited to just two demonstration projects. One is the Boundary Dam CCS Project that was retrofitted with a FOAK post-combustion carbon capture system by SaskPower on an existing coal-fueled EGU at its Boundary Dam Power Station in Canada. The other is the Petra Nova CCS Project that NRG brought online in January 2017 at an existing coal-fueled unit at its W.A. Parish Power Generating Station in Texas.

The Boundary Dam CCS Project came online in 2014 as the world's first post-combustion application of CCS on SaskPower's Boundary Dam Unit 3. The SaskPower project involved the use of a carbon capture system using an amine solvent that was designed to capture up to 90 percent of the CO_2 emissions from a unit burning lignite. However, the Boundary Dam CCS Project has encountered a number of design problems. One major problem has resulted from the high flue gas temperatures and particulate content that have interfered with and effectively contaminated the amine chemistry of the CO_2 capture system. This contamination has caused several major problems for the operation of the capture system. First, it has reduced the availability of the Boundary Dam CCS system due to more frequent cleaning that is required for the CCS components. In particular, the CCS system initially had to be taken offline every four to five weeks to remove the fly ash that was adhering to surfaces.[10] Second and more importantly, it has reduced the capture rate by impairing the effectiveness of the amine-based chemistry system that is used for separating CO_2 emissions from the flue gas. As a result of these problems, the capture system operated only 40 percent of the time during the first year of operation, and the CO_2 capture rates continue to be well below the design capture rate of 90 percent.[11] This and other problems[12] have not only substantially increased the operating costs of the CCS technology, but also contributed to the decision of SaskPower to cancel its plans to install the same capture system on other units at the Boundary Dam facility. These problems[13] point to design and operational problems that need to be addressed before CCS technology is shown to be adequately demonstrated.

The NRG Petra Nova CCS Project also involves a FOAK application of a post-combustion CCS technology designed to capture up to 90 percent of the CO_2 emitted from a 240-MW flue gas stream of Unit 8 at the Parish facility, whose nameplate capacity is 654 MW. Assuming the design capture rate can be achieved consistently, the Petra Nova Project has the capability to achieve a 33 percent reduction in overall CO_2 emissions from Unit 8.[14]

Like the Boundary Dam CCS Project, NRG has encountered numerous design and operating problems. Most notably, the Petra Nova Project has been unable to demonstrate the integration of the thermal load of the capture technology into the boiler steam cycle of Unit 8. As a result, NRG has been forced to build and operate an entirely new 75-MW cogeneration unit to supply the parasitic electrical and steam load for the operation of the carbon capture system. Furthermore, the Petra Nova Project has been operating for slightly more than two years. Several more years of operation under variable load conditions and operating scenarios are needed before any conclusions can be drawn regarding the long-term performance and reliability of the Petra Nova capture system.

In addition to the technology challenges, the Petra Nova Project has received substantial financial support that would most likely not be available for other utility applications of CCS. One major source of financial support is significant government funding from the Department of Energy (DOE) under its Clean Coal Power Initiative (CCPI) to demonstrate CCS at the Parish generating unit. The other is supplemental revenues from selling the captured CO_2 for enhanced oil recovery (EOR) in the nearby Weyburn oil fields in Texas. An adequately demonstrated capture system must be one that is available at reasonable cost, and these additional revenue streams will not be available to reduce the excessively high costs of this capture technology at other coal-fueled applications in the future.

None of the other smaller-scale demonstration projects—20-MW and 25-MW slipstreams—cited by EPA in the 2015 Rule can support a finding that CCS is adequately demonstrated. Likewise, the deployment of capture technologies for non-electricity applications—such as the Archer Daniels Midland's biofuel plant in Decatur, Illinois[15] and the Valero Oil Refinery in Port Arthur, Texas[16]—do not show that capture technologies are adequately demonstrated because these industrial applications are very different from the application of CCS at coal-fueled power plants.

CCS demonstration projects show that costs are excessive and projects would never have been undertaken without subsidies.

Even if partial CCS was adequately demonstrated (which it is not), the exorbitantly high costs of installing and operating any carbon capture system preclude the Agency from determining that CCS is BSER for new coal-fueled EGUs. The CAA requires EPA to take into account "the cost of achieving the required emissions reductions," and the Agency has an obligation to eliminate those emission reduction systems that are too costly. Courts have affirmed this interpretation on multiple occasions, stating that EPA may not adopt performance standards that impose capital and operating costs determined to be "exorbitant," "greater than the industry could bear and survive," "excessive," or "unreasonable." Furthermore, EPA has repeatedly acknowledged that any control system cannot be considered BSER if it is too costly because such unreasonable or excessive costs would indicate that the system in question is not the "best." Very high costs were incurred by Boundary Dam and Petra Nova, the first wave of first of FOAK projects now underway for demonstrating utility-scale CCS technologies under a range of commercial applications and operating conditions.

SaskPower's reported capital cost for Boundary Dam is more than twice the amount of EPA's capital cost estimates for building a second-of-a-kind CCS project at an entirely new power plant.[17] SaskPower has also incurred substantial additional costs to remedy design flaws and operational problems, such as Boundary Dam's amine solvent-based process used for extracting CO_2 from the flue gas stream.[18] To help offset these costs, Boundary Dam has received $250 million in grant funding from the Canadian government, which amounts to approximately 20 percent of the total project cost.[19] In addition, the project relies on revenue from sale of the captured CO_2 for EOR.[20]

Similarly, Petra Nova would not have been financially viable without substantial subsidies from DOE, as well as the additional revenues from selling the captured CO_2 for EOR. These additional revenue streams are essential to offsetting the substantially higher costs to build and operate this FOAK application.

The statute precludes demonstration projects receiving DOE funding.

The Energy Policy Act of 2005 (EPAct05) prohibits EPA from making a determination that an emission control technology is "adequately demonstrated" under CAA section 111(b) based on a demonstration project that receives federal funding under DOE's Clean Coal Power Initiative (CCPI).[21] As the legislative history to this provision makes clear, Congress added the EPAct05 section 402(i) limitation out of concern over how EPA might use information from federally subsidized demonstration projects. Congress' specific concern was that EPA might conclude that a technology was "adequately demonstrated" because the technology used at a project funded through an EPAct05 program.[22] Notably, Congress expressly limited CCPI funding to technologies that have not been "in commercial service" or "demonstrated on full scale" and then directed EPA not to conclude that a technology is "adequately demonstrated" if the technology received CPPI funding. A finding of "adequately demonstrated" is permissible only when the technology has been adequately demonstrated elsewhere at other facilities that did not receive any such federal assistance.[23]

Partial CCS is not BSER due to geographic limitations.

Any performance standard set under section 111 of the CAA must be achievable for all types of stationary sources throughout the nation to which the standard applies. The Agency has traditionally followed this approach when setting NSPS for affected source categories[24] and has expressly confirmed the standard must be based on the "best technology available nationwide, regardless of climate, water availability, and many other highly variable case-specific factors."[25] The 2015 NSPS based on partial CCS fails to meet this requirement. The use of any carbon capture technology is limited to only certain parts of the country due to the lack of geological storage sites in many states, the scarcity of water across large areas of the west, and the lack of a sufficient pipeline system for transporting the captured CO_2 emissions from different locations around the U.S.

In the preamble to the Proposed Rule, EPA presented an updated analysis of geological storage capacity in the U.S. That updated analysis concludes that, while the potential storage capacity appears large, the opportunities for CO_2 storage "may not be as widely geographically available as assumed in the 2015 analysis" due to "site-specific technical, regulatory, and economic considerations."

Both DOE and the U.S. Geological Survey (USGS) have developed only high-level assessments of potential geological storage capacity but have not prepared any detailed analysis regarding the adequacy of any particular underground reservoir for CO_2 storage based on site specific characterization and testing.[26] A "possible" geological sequestration site is not necessarily an acceptable site. In areas where oil and gas operations are not common, no geologic storage sites have been characterized sufficiently to guarantee they will provide secure permanent storage for 30 years of CO_2 generated by a commercial-scale power plant.

In addition, actual storage capacity is likely to be significantly less than the estimates developed by these agencies. USGS researchers have in fact expressed concern that due to issues such as reservoir pressure limitations, boundaries on migration of CO_2, and acceptable injection rates over time, "it is likely that only a fraction" of the high-level estimated technically accessible CO_2 storage resources could be available.[27] Similarly, the DOE assessment fails to evaluate the economic viability or lack of accessibility to storage resources due to land management or regulatory restrictions. For example, geographic regions with fresh water could be precluded from consideration in order to protect water resources from potential contamination.[28]

EPA should recognize that sequestration and storage opportunities are available only at plant sites near CO_2 pipelines or underground geological formations suitable for long-term containment of captured CO_2. These suitable geological reservoirs, however, are not evenly distributed across the U.S. The DOE assessment on potential CO_2 storage capacity indicates that ten states either have no geological storage sites or have yet to be assessed, while another five states have very limited potential storage capacity.[29] This means that at least 15 states lack, or might lack, adequate geological storage capacity necessary for operation of CCS technologies.

The only way to address this problem is to construct the necessary pipeline capacity for transporting captured CO_2 from different locations. The construction of a CO_2 pipeline transportation system of this magnitude would be no easy task. There are many potential legal and regulatory barriers to such a buildout. One key issue relates to the cumbersome process for the siting, land acquisition and construction of a greatly expanded pipeline system. Another issue relates to the long lead times and large capital investments that will be necessary to build a new pipeline system. Without providing an explanation as to how these issues will be addressed, it is unreasonable to assume that a CO_2 pipeline system could provide assurance that electricity generators in states with no or little CO_2 storage capacity will have cost-effective access to storage capacity in other states.

Last, the scarcity of water across large areas of the country, particularly in the western U.S., is another limitation. The Agency itself has recognized that "substantial amounts of water" are needed to operate carbon capture systems and that the lack of sufficient supplies of water would be a significant barrier to the deployment of CCS in many areas of the country.[30] This geographic limitation provides further reason to eliminate partial CCS as BSER. As discussed above, EPA has an obligation under CAA section 111 (as interpreted by the courts) to set performance standards that are achievable by all EGUs within the source category and not just those units located in areas that have adequate supplies of water.

EPA's determination that partial CCS is not adequately demonstrated is consistent with permit decisions.

EPA's proposal to determine that partial CCS is not adequately demonstrated is consistent with past determinations regarding "best available control technology" (BACT) for limiting CO_2 emissions from new facilities under the New Source Review program. Between 2011 and 2017, both EPA and state permitting authorities have determined on many occasions that CCS is neither demonstrated at a utility scale nor a cost-effective commercially available technology for new coal-fueled power plants.[31] A similar record exists for the non-electric generation projects that have received a CO_2 BACT permit limit for industrial facilities even in the case of those "industrial sources with existing, nearly pure CO_2 process streams … that could implement CO_2 capture at little or no net cost."[32]

These BACT determinations clearly indicate that CCS is not adequately demonstrated and, therefore, should not be used as the basis for setting the CO_2 NSPS for new coal-fueled power plants. In addition, this conclusion is underscored by the fact that the CAA stipulates that the NSPS must serve as the floor (minimum level of stringency) in setting the BACT limits for new sources.[33] In effect, the NSPS sets minimum emissions control levels for new sources, while the permitting authority can increase the stringency beyond the NSPS levels on a case-by-case basis through the BACT permitting process. It makes little sense for EPA to set a more stringent CO_2 control level under the less stringent NSPS process than that which EPA and state permitting authorities have recently determined on a source-by-source basis through the more stringent BACT process.

EPA should set NSPS based on the most efficient steam cycle conditions.

In addition to eliminating partial CCS as BSER for the many reasons discussed above, EPA is proposing to determine that the most efficient demonstrated steam cycle in combination with best operating practices is BSER for new and reconstructed coal-fueled EGUs.[34] In particular, the Proposed Rule specifies that BSER is the use of high efficiency supercritical boiler designs for "large" EGUs and most efficient subcritical boiler designs for "small" EGUs.[35] Furthermore, best operating practices are defined to include installation of boiler components (such as economizers and feedwater heaters) and the operation of the unit in such a manner to maximize overall generating efficiency.[36]

ACCCE strongly supports the new BSER determination proposed by EPA, instead of other technology options, such as co-firing with natural gas and hybrid solar energy and fossil-fueled generation.[37] The use of best available advanced generation technologies will result in higher steam temperatures and pressures, which in turn increase the efficiency of converting the thermal energy in the steam to electrical energy. The overall efficiency of the steam boiler can be further enhanced and maximized significantly through the implementation of best operating practices for the maintenance and operation of the boiler.

These improvements in generating efficiency will translate in meaningful environmental and energy benefits, as compared to less efficient generation. EPA estimates that supercritical steam conditions will reduce all pollutants approximately three to five percent, as compared to subcritical units. EPA also estimates a nine percent reduction in CO_2 emissions for small EGUs compared to the CO_2 emission levels achieved by small units operating at typical subcritical steam conditions. Furthermore, efficiency gains will lower the cost of power generated, which can help offset increases in capital and operating costs.

Most importantly, these advanced generation technologies and operating practices are technically feasible and can be implemented with modest additional capital and operating costs. Supercritical steam generating technologies (including coal-fueled EGUs operating at ultra-supercritical steam conditions) are well demonstrated in the U.S. and at least 14 other countries. Ultra-supercritical EGUs tend to be large units of 800 MW or more and have been built in many countries, including the U.S., Germany, Netherlands and Japan. As a result, electricity generators have extensive experience with the design, cost and operating characteristics of EGUs with supercritical boiler designs for a wide range of coal types, load duties, emission control configurations and ambient conditions.

In summary, ACCCE agrees with EPA's proposal to select as BSER the most efficient demonstrated steam cycle in combination with best operating practices as BSER for new and reconstructed coal-fueled EGUs. These generating technologies have been adequately demonstrated and will reduce CO_2 emissions from new and reconstructed coal-fueled EGUs.

EPA should establish CO_2 performance standards for subcategories of new coal-fueled EGUs.

EPA's proposed standard of 1,900 lbs. CO_2/MWh-gross for large EGUs is roughly consistent with the results of analysis sponsored by ACCCE in 2014 and updated in 2017.[38] The 2014 analysis accompanied our comments on the NSPS the Agency had proposed at that time; the 2017 analysis was done simply to update the 2014 analysis with additional data from the same coal-fueled units that were evaluated in the earlier report. The 2017 study included data from 28 EGUs that reflect state-of-art coal-fueled technology. All but one of the units entered commercial service on or after January 1, 2007 and had operated for at least 18 months by September 30, 2016.

The 28 EGUs used subcritical, supercritical or circulating fluidized bed designs and burned eastern bituminous coal, Powder River Basin (PRB) coal or lignite. Carbon dioxide emissions data from the 28 units were evaluated using a statistical procedure EPA had previously used to select achievable emission limits for a different pollutant.[39] This statistical procedure was used to determine the annual average emission rate that EGUs would not be expected to exceed more than once every 10 years, the criterion used previously by EPA.

Based on the analysis, ACCCE recommended that EPA establish different CO_2 performance standards for at least two subcategories of coal-fueled generating units: one for supercritical boilers burning either bituminous or subbituminous coals and another subcategory for units that burn lignite. Based on the statistical analysis and the once-in-ten-years criterion, we suggested an achievable emissions limit of slightly more than 1,900 lbs./MWh for coal-fueled generating units burning either eastern bituminous or PRB coal and a limit of slightly less than 2,200 lbs. CO_2/MWh for units burning lignite. However, we strongly caution EPA to consider the significant effects of load on the achievability of any CO_2 performance standard it adopts because our analysis showed that operating at less than 80 percent of maximum load can increase CO_2 emissions.

The proposed standards for modified coal-fueled EGUs are not achievable based on efficiency upgrades.

The Proposed Rule requires the establishment of unit-specific CO_2 performance standards that would limit each modified EGU to its lowest annual CO_2 emission rate achieved since 2002, with a floor of (no lower than) 1,900 lbs. CO_2/MWh-gross for large units and 2,000 lbs. CO_2/MWh-gross for small units.[40] This methodology for setting unit-specific standards will most likely result in standards that are unachievable for many modified units for the following reasons.

First, any modified coal-fueled EGU would have to comply with the lowest annual CO_2 emissions rate that it achieved during a historic look-back period dating back to 2002. These past CO_2 emission rates could be very difficult for many existing coal-fueled EGUs to achieve consistently given that the average capacity factor for the coal fleet has decreased significantly over the last 15 years, and this trend is projected to continue for the foreseeable future.[41] Many existing coal-fueled EGUs are no longer operating as baseload generating units, but instead operating as cycling units at much lower capacity factors in response to market conditions. As a general matter, coal-fueled EGUs operating at lower load levels and fluctuating duty cycles operate at lower efficiencies and higher CO_2 emission rates, as compared to units operating as baseload.[42]

Second, a recent technical analysis evaluated the feasibility of modified coal-fueled EGUs achieving their unit-specific CO_2 performance standards under the Proposed Rule.[43] That analysis – which ACCCE endorses and incorporates by reference into its comments – indicated that about 40 percent of the large EGUs having the greatest potential to undergo a modification[44] have achieved annual CO_2 emissions rates below the floor levels during the look-back period and, therefore, would become subject to a stringent emissions rate of 1,900 lbs. CO_2/MWh-gross, the same limit that EPA has proposed for new coal-fueled EGUs. Moreover, half of the affected units, if modified, would have to reduce their annual CO_2 emission rate by 5 percent or more from 2017 levels and 11 percent from their highest CO_2 rate since 2002.

Such reductions are likely to be unachievable through efficiency improvements. This means that a large number of units, if they were modified, could be forced to shut down because the reductions required for compliance are not feasible or sustainable due to operating conditions, particularly when the modified units are operating at lower capacity levels and different duty cycles in response to market conditions.

In light of this information, we urge EPA to not use this approach to establish performance standards for modified EGUs.

The CAA requires EPA to make an endangerment finding before regulating CO2 emissions from EGUs.

The CAA authorizes EPA to establish performance standards for new, modified, and reconstructed sources if those sources are in a source category that EPA has found to emit pollutants at levels that "cause or contribute" to the "endangerment" of public health and welfare.[45] This determination is commonly referred to as the "endangerment finding" and is a prerequisite for the regulation of any source category under section 111 of the CAA.

In the case of the 2015 NSPS rulemaking, EPA concluded it was unnecessary to make an entirely new endangerment finding when setting CO_2 performance standards because the Agency had already made an endangerment finding for the EGU source category in prior NSPS rulemakings in which the Agency set performance standards for other air pollutants, such as SO_2, NO_x and particulate matter. Furthermore, the Agency asserted that even if it were required to make a specific endangerment finding for CO_2 emissions from EGUs in order regulate them under section 111(b), such an endangerment finding could easily be made based on "the same facts that provided the rational basis" for regulating CO_2 from the EGU source category under the 2015 NSPS rulemaking.[46] Although EPA is proposing to retain this interpretation of the CAA, it recognizes that "alternative interpretations … may be permissible, either as a general matter or specifically as applied to GHG emissions."[47]

ACCCE does not agree with EPA for the following reasons.

First, EPA was incorrect to argue in the 2015 NSPS rulemaking that a new endangerment finding was unnecessary because the Agency had already made that finding for the EGU source category in prior NSPS rulemakings. Those prior endangerment findings were made many years ago for different source categories and different pollutants (e.g., SO_2 and NO_x).[48] In particular, EPA made one endangerment finding in 1971 for "steam generators"[49] and another finding in 1977 for "stationary gas turbines."[50] By contrast, the finding made in the 2015 NSPS rulemaking relates to an entirely new source category that was specifically created for regulating CO_2 emissions from "fossil fuel-fired EGUs."

Second, EPA cannot rely on the endangerment finding that it made in 2009 for regulating motor vehicles under section 202 of the CAA. That finding does not satisfy the statutory obligations for regulating EGUs under section 111 of the CAA. The 2009 finding was made for "six well-mixed greenhouse gases," not

CO_2 alone. In addition, EPA made the finding for an entirely different source category, motor vehicles not fossil fuel-fired EGUs, and did so for the sole purpose of establishing motor tailpipe standards for GHG emissions. EPA has never found that CO_2 alone endangers public health or welfare, let alone made such a finding for CO_2 emissions from the new EGU source category that was codified at new Subpart TTTT in 2015.

Conclusion

ACCCE appreciates the opportunity to submit these comments in support of the Proposed NSPS Rule for coal-fueled EGUs. Besides following the letter of the CAA, the adoption of the proposed NSPS will remove a major barrier to adding new coal-fueled generation in the future for purposes of maintaining fuel diversity, grid reliability, grid resilience and fuel security. If you have any questions, please contact me at mbloodworth@americaspower.org.

Sincerely,

Michelle Bloodworth
President and CEO
America's Power / ACCCE

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[1] *Review of Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources; Proposed Rule*, 83 Fed. Reg. 65,424 (December 20, 2018).

[2] *Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units*, 80 Fed. Reg. 64,510, 64,577-79 (Oct. 23, 2015).

[3] A list of ACCCE members is attached.

[4] As discussed in the next section, the electric power sector has retired or announced its plan to retire almost 121,000 megawatts of coal-fueled electric generating capacity since 2010.

[5] *See* ACCCE Paper, entitled "Retirement of Coal-Fired Electric Generating Units" (February 7, 2019) (ACCCE Paper on Coal-Fired EGU Retirements). The ACCCE paper, which is attached hereto, provides a list of retirements of all coal-fired EGUs on a state-by-state basis since 2020.

[6] Affected coal-fueled EGUs include both steam electric generating units and integrated gasification combined cycle (IGCC) units that are fueled by coal or coal-derived fuels. All references to coal-fueled EGUs for which revised performance standards have been proposed include coal-fueled IGCC units.

[7] ACCCE Paper on Coal-Fired EGU Retirements.

[8] 83 Fed. Reg. at 65,436.

[9] The Federal Energy Regulatory Commission has initiated a proceeding to evaluate the resilience of the bulk power system. In addition, PJM and ISO-NE are conducting analyses aimed at addressing fuel security concerns in their regions. ACCCE has urged FERC to speed up its proceeding and require other ISO/RTOs to conduct fuel security analyses.

[10] *See* Duckett, A., "The Privilege of Being First," The Chemical Engineer (May 1, 2018), at https://www.thechemicalengineer.com/features/the-privilege-of-being-first/ (Duckett Paper).
[11] *See* Duckett Paper.
[12] SaskPower had to undertake additional major renovations to its CCS process in 2015 and 2017 to address unanticipated problems with the system's design. For example, the utility had to install a spray curtain and demister top wash spray to address particulate matter contamination and installed redundant systems to allow CCS components to be cleaned without taking the capture system offline. *See* Duckett Paper. Other unanticipated changes to address CCS problems include adding activated carbon treatment to resolve unanticipated foaming in the amine solution; replacing the original steam desuperheater, which was unable to sufficiently cool the steam; replacing the amine tank; and installing new coolers on the CO_2 compressor—a project that reportedly took longer than anticipated due to the unique size and complexity of the compressor required for this CCS process. *Id.*
[13] SaskPower has been successful in resolving some of these problems (such as particulate matter contamination) while efforts are still underway to address other problems (such as the contamination of the amine solution). *See* Duckett Paper.
[14] *See* https://www.eia.gov/todayinenergy/detail.php?id=33552
[15] This demonstration project came online in 2017 and has so far captured one million tons of CO_2 emissions that are being generated as a by-product of ethanol biofuels production process. The captured CO_2 is being injected and stored for the first time into a deep saline reservoir pursuant to a Safe Drinking Water Ac Class VI permit for underground CO_2 storage. Lou Hrkman, DOE Deputy Assistant Secretary, Clean Coal and Carbon Management, PowerPoint entitled: "The Future of Coal: 'Carbon Free Fossil Energy'" (February 12, 2019) (Hrkman PowerPoint on Carbon Free Fossil Energy).
[16] The CO_2 capture system was installed at the Port Arthur refinery came online in 2013 and has been capturing CO_2 from two large methane reformers. The captured gas is being transported by pipeline to oil fields in eastern Texas where it is injected for EOR purposes. Hrkman PowerPoint on Carbon Free Fossil Energy.
[17] In particular, Boundary Dam's reported capital cost for retrofitting CCS components at an existing generating unit was $11,300 per kilowatt, as compared to EPA's own capital cost estimates of $5,006 per kilowatt for building a "second-of-a-kind" CCS project at a completely new power plant with CCS.
[18] Duckett Article.
[19] Coal Industry Advisory Board, "An International Commitment to CCS: Policies and Incentives to Enable a Low-Carbon Energy Future" at page 19 (November 21, 2016) (CIAB Paper).
[20] CIAB Paper at page 19.
[21] In particular, Section 402(i) of EPAct05 places the following limitation on EPA's authority to regulate stationary sources under section 111 of the CAA:

> No technology, or level of emission reduction, solely by reason of the use of the technology, or the achievement of the emission reduction, by 1 or more facilities receiving assistance under this Act, shall be considered to be … adequately demonstrated for purposes of section 111 of the Clean Air Act (42 U.S.C. 7411).

42 U.S.C. § 15962(i). A similar prohibition is imposed on demonstration projects that have received an investment tax credit under section 48A of the IRS Code. *See* Section 1307 of EPAct05, codified at 26 U.S.C. §48A(g).
[22] For example, the relevant House Energy and Commerce Committee Report "specifies that the use of a certain technology by any facility assisted under this subtitle or the achievement of certain emission reduction levels by any such facility will not result in that technology or emission reduction level being considered … 'adequately demonstrated'" when setting new source performance standards under section 111 of the CAA. H. Comm. Energy and Commerce, Report to Accompany H.R. 1640, the "Energy Policy Act of 2005," H.Rep. 109–215 at 238 (July 29,

2005). H.R. 1640 is the precursor to EPAct05 and provided the blueprint for many of the clean coal programs at issue here. The Report includes a similar explanation of the prohibition contained in the Clean Air Coal Program (which became EPAct05 § 421). *Id.* at 240.

[23] The CCPI program funds projects that "advance efficiency, environmental performance, and cost competitiveness *well beyond* the level of technologies that are *in commercial service* or *have been demonstrated* on a scale" that the DOE "determines is sufficient to demonstrate that commercial service is viable." 42 U.S.C. § 15962(a) (emphases added). In other words, the stated purpose of the CCPI program is to promote the development of technologies that are not yet adequately demonstrated. Moreover, because a statutory prerequisite for a technology to receive CCPI funding is that it is not in "commercial service" or "viable," EPA has an extra hurdle to prove that any level of emission reduction achieved by CCPI-funded facilities is now viable and adequately demonstrated.

[24] In particular, EPA sets NSPS limits at levels that 99 percent of the new affected stationary sources will be able to apply. *See, e.g.*, EPA, EPA-453/R-94-012, New Source Performance Standards, Subpart Da – Technical Support for Proposed Revisions to NOx Standard at Section 3.2.3 (Analysis of Long-Term Continuous Emission Monitoring Data) at 3-43, 3-49, 3-55 (June 1997) ("1997 Subpart Da TSD"), *available at* http://nepis.epa.gov/Exe/ZyPURL.cgi?Dockey=2000IMGW.TXT.

[25] Letter from Gary McCutchen, Chief, New Source Review Section, EPA OAQPS, to Richard E. Grusnick, Chief, Air Division, Ala. Dep't of Envtl. Mgmt. at 1 (July 28, 1987) ("McCutchen Letter"), *available at* http://www.epa.gov/region7/air/nsr/nsrmemos/crucial.pdf. One notable example where EPA reaffirmed this approach is EPA's NSPS rule to revise the Subpart Da performance standards in 2005 for fossil-fueled EGUs, when the Agency rejected supercritical boiler design, IGCC technology, and the use of clean fuels as BSER due in part to the unavailability of these emissions reduction options by all affected sources within the EGU source category. 70 Fed. Reg. at 9712 -15.

[26] *See* 83 Fed. Reg. at 65,441. "Risk, Liability, and Economic Issues with Long-Term CO_2 Storage—A Review," 26 Natural Resources Research Vol. 26 Issue 1 pp. 89-112 (Jan. 2017), https://link.springer.com/article/10.1007/s11053-016-9303-6?wt_mc=Internal.Event.1.SEM.ArticleAuthorOnlineFirst

[27] *See* Steven T. Anderson, "Cost Implications of Uncertainty in CO_2 Storage Resource Estimates: A Review," Natural Resources Research Vol. 26 Issue 2 pp. 137-159 (Apr. 2017), https://link.springer.com/article/10.1007/s11053-016-9310-7#enumeration; Steven T. Anderson,

[28] DOE, Office of Fossil Energy, NETL, THE UNITED STATES 2012 CARBON UTILIZATION AND STORAGE ATLAS, FOURTH EDITION (DOE Atlas), *available at* http://www.netl.doe.gov/research/coal/carbon-storage/atlasiv.

[29] DOE Atlas.

[30] 83 Fed. Reg. at 65,422.

[31] *See* 83 Fed. Reg. at 65,441.

[32] *See* 83 Fed. Reg. at 65,441.

[33] *See* Section 169(3) (prohibiting the BACT limits to "exceed the emissions allowed by any applicable [NSPS] standard established pursuant to section 111").

[34] 83 Fed. Reg. at 65,424.

[35] In particular, the Agency defines supercritical steam conditions to mean that the boiler is designed to operate at pressures greater than 22 MPa (3,205 psi) and temperatures greater than 550 degrees Celsius (1,022 degrees Fahrenheit). *See* 83 Fed. Reg. at 65,447. In additional, the Proposed Rule defines a "large" EGU as a unit having a maximum heat input of 2,000 MMBtu/h, which generally translates to a unit with a nameplate generating capacity of about 200 MW. *Id.* at 65,427.

[36] 83 Fed. Reg. at 65,424.

[37] In particular, EPA evaluated the following control technology configurations as potentially representing BSER: conversion to or co-firing with natural gas; the use of "combined heat and

power" technologies; development of hybrid generating technologies that combines solar energy with fossil-fueled generation; and use of the integrated gasification combine cycle technologies. 83 Fed. Reg. at 65,444. As a general matter, ACCCE agrees with EPA's decision to eliminate each of those control technology configurations for a variety of reasons, including excessive costs, limitations on availability, energy impacts, as well as various other practical and technical considerations. For example, we agree with EPA's decision not to select co-firing with natural gas at coal-fired EGUs is not available in many parts of the country, would be cost-prohibitive for many units, results in an inefficient use of natural gas, and is legally impermissible because it would require a redefinition of the source. 83 Fed. Reg. at 65,445; see also 83 Fed. Reg. at 44,752-53 (discussing prohibition on redefining the source).

[38] *See* J. Edward Cichanowicz, *Evaluation of CO_2 Emissions Rates from State-of-Art Coal-Fired Electric Generating Units* (May 2014); J. Edward Cichanowicz, Updated Evaluation of *CO_2 Emissions Rates from State-of-Art Coal-Fired Electric Generating Units (Updated Cichanowicz Analysis)*.

[39] *See* Updated Cichanowicz Analysis.

[40] *See* 83 Fed. Reg. at 65,427.

[41] *Annual Energy Outlook 2019: with projections to 2050, Energy Information Agency*, January 24, 2019, available at https://www.eia.gov/outlooks/aeo/pdf/aeo2019.pdf EIA specifically projects that coal-fired generating capacity factor through the year 2022 will be between 50-55 percent. *Id.*

[42] Many factors are responsible for this trend. Among the most significant are a compromise in the pressure and temperature of steam delivered to the turbine, and a reduction in boiler thermal efficiency due to the need to operate the boiler at higher excess air levels to maintain flame stability and optimal heat transfer.

[43] J. Edward Cichanowicz, Critique *of EPA's CO_2 NSPS for Modified Coal-fired EGUs (February 2019) (*Cichanowicz Critique).

[44] The coal-fired EGUs selected for the analysis were 177units that are more likely to undertake major capital investments and thereby become subject to performance standards for modified units due to age, generating capacity and emissions control equipment installed. Cichanowicz Critique at pages 1-2.

[45] Specifically, section 111(b)(1) requires EPA to list those categories of stationary sources that the EPA Administrator finds "cause or contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare."

[46] 83 Fed. Reg. at 65,432.

[47] 83 Fed. Reg. at 65,432, footnote 25.

[48] 80 Fed. Reg. at 64,529-30.

[49] 36 Fed. Reg. 5931 (Mach 31, 1971).

[50] 42 Fed. Reg. 53,657 (October 3, 1977).

Attachment 1

AMERICA'S POWER
ACCCE | Reliable • Secure • Resilient • Affordable

2019 Member Organizations

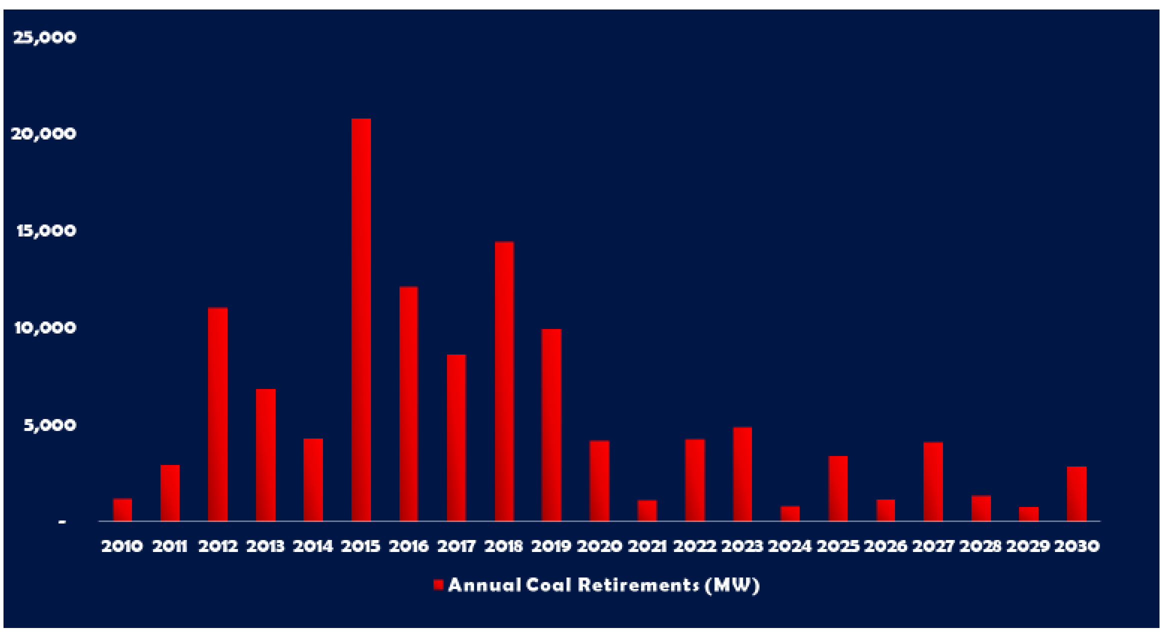
Alliance Resource Partners, LP
American Electric Power
Associated Electric Cooperative Inc.
Berwind Natural Resource Corporation
Big Rivers Electric Corporation
BNSF Railway
Buckeye Power, Inc.
Carbon Utilization Research Council (CURC)
Caterpillar Inc.
Charah Solutions, Inc.
CONSOL Energy
CSX Corporation
Crounse Corporation
Drummond Company, Inc.
GMS
Jennmar Corporation
John T. Boyd Company
Kentucky Coal Association
Kentucky River Coal Corporation
Komatsu Mining
Murray Energy Corporation
Natural Resource Partners L.P.
Norfolk Southern Corporation
Oglethorpe Power Corporation
Peabody Energy Corporation
PowerSouth Energy Cooperative
Prairie State Generating Company, LLC
Rosebud Mining Company
Southern Company
Union Pacific Railroad
Western Fuels Association
White Stallion Energy

Attachment 2

RETIREMENT OF COAL-FIRED ELECTRIC GENERATING UNITS[1]
As of February 7, 2019

All Retirements

Since 2010, U.S. power plant owners have announced the retirement or conversion to other fuels of a large number of coal-fired electric generating units.[2] The table on the following pages summarizes all publicly announced retirements through 2030. The table shows that **654** coal-fired generating units in 43 states—totaling nearly **121,000** megawatts (MW) of generating capacity—have retired or announced plans to retire through 2030. Retirements are approaching **40 percent** of the coal fleet that was operating in 2010. Through the end of 2018, approximately 82,000 MW of coal-fired generating capacity had retired. In 2019 and 2020, an additional 14,000 MW are expected to retire, bringing total retirements to 96,000 MW by the end of 2020. The chart below shows these coal retirements over the period 2010-2030.



EPA-Attributed Retirements

The table also includes retirements that have been explicitly attributed to EPA regulations and policies. These EPA-caused retirements through 2030 total **464**

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[1] Retirements and conversions are based primarily on public announcements by the owners of the coal units. We also use other information sources that are reliable. These retirements and conversions are *not* based on modeling projections. We do not include small (less than 25 MW) cogeneration units. Since most of these units are retiring, not converting to another fuel, we use the term "retirements" in this paper to characterize units that may be *either* retiring or converting.

[2] In 2010, according to EIA, the U.S. coal fleet was comprised of 1,396 electric generating units located at 580 power plants for a total electric generating capacity of approximately 317,000 MW.

units in 37 states and represent over **78,000 MW** of coal-fired generating capacity. Of the total, nearly 60,000 MW had already retired by the end of 2018.

ISO/RTO Retirements

There are seven ISO/RTO regions in the U.S.: California ISO (CAISO), Texas ISO (ERCOT), Midcontinent ISO (MISO), ISO New England (ISONE), New York ISO (NYISO), PJM Interconnection (PJM) and Southwest Power Pool (SPP). Over **56,600 MW** of coal-fired generating capacity in these regions had retired by the end of 2018. An additional **9,200 MW** are expected to retire in these regions in 2019 and 2020, 7,400 MW of which are due to wholesale electricity market conditions. The result is that a total of over **66,000 MW** will have retired in these regions between 2010 and the end of 2020. The regions with the most retirements from 2010 through 2020 are PJM (35,000 MW), MISO (14,800 MW), ERCOT (5,800 MW) and SPP (5,000 MW).

	MW Retiring	# of Units Retiring
Ohio	13,565[3] / 6,390[4]	62 / 40
Pennsylvania	8,501 / 5,504	42 / 30
Indiana	6,532 / 6,092	39 / 34
Texas	6,291 / 1,368	11 / 3
Alabama	5,166 / 5,166	26 / 26
Illinois	5,065 / 3,091	20 / 14
Michigan	5,054 / 4,046	46 / 31
Florida	4,649 / 1,465	14 / 7
North Carolina	4,519 / 2,713	37 / 20
Kentucky	4,453 / 3,741	22 / 18
West Virginia	4,063 / 2,737	21 / 18
Georgia	3,730 / 3,228	17 / 15
Virginia	3,367 / 2,349	31 / 16
Arkansas	3,293 / 3,293	4 / 4
Arizona	3,277 / 3,277	7 / 7
Wisconsin	2,836 / 1,222	27 / 16

[3] Total coal retirements.
[4] Coal retirements attributed to EPA regulations and policies.

Nevada	2,657 / 0	8 / 0
Tennessee	2,651 / 2,651	17 / 17
Oklahoma	2,401 / 2,401	5 / 5
Colorado	2,393 / 1,687	19 / 16
Missouri	2,339 / 2,324	24 / 23
Minnesota	2,291 / 2,153	17 / 15
New Mexico	2,244 / 2,244	7 / 7
Montana	2,224 / 130	5 / 1
Utah	2,072 / 272	7 / 5
Iowa	1,823 / 1,571	33 / 29
South Carolina	1,759 / 1,759	14 / 14
New York	1,708 / 475	14 / 3
Massachusetts	1,598 / 1,346	8 / 6
New Jersey	1,479 / 259	6 / 2
Washington	1,340 / 0	2 / 0
Mississippi	1,066 / 706	4 / 2
Nebraska	726 / 611	6 / 5
Maryland	618 / 115	5 / 2
Oregon	585 / 585	1 / 1
Louisiana	575 / 575	1 / 1
Connecticut	564 / 0	2 / 0
Kansas	538 / 477	7 / 6
Delaware	359 / 0	4 / 0
California	317 / 0	6 / 0
North Dakota	187 / 0	1 / 0
Wyoming	45 / 45	4 / 4
South Dakota	22 / 22	1 / 1
43 / 37 States	**120,939 / 78,088 MW**	**654 / 464 Units**