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America's Power Comments on
the Proposed Carbon Rule for Fossil-Fuel Power Plants

America's Power submits the following comments on the proposed rule to regulate carbon dioxide (CO_2) emissions from fossil-fueled electric power plants (Proposed Rule or Carbon Proposal).[1] Authorized under section 111 of the Clean Air Act (CAA or Act), the Proposed Rule would establish emission guidelines for states to adopt CO_2 performance standards for existing coal-fired electric generating units (EGUs) and other existing fossil fuel-fired EGUs as well as adopt new source performance standards (NSPS) for new fossil fuel-fired stationary source combustion turbines. The focus of these comments is on the Environmental Protection Agency's (EPA or Agency) Carbon Proposal to regulate CO_2 emissions from existing coal-fired EGUs under section 111(d) of the CAA.

By way of background, America's Power is the only national trade organization whose sole mission is to advocate at the federal and state levels on behalf of coal-fired electricity and the supply chain that supports the nation's coal fleet. Our membership is composed of electricity generators, coal producers, barge operators, and equipment manufacturers.

Overview of Comments on the Carbon Proposal

The Proposed Rule suffers from many fundamental legal flaws and technical deficiencies that EPA can remedy only by withdrawing the Proposed Rule, conducting realistic and meaningful analysis, and then reproposing an entirely new rule. These legal flaws and technical deficiencies include the following:

- ***The Carbon Proposal would force the premature shutdown of coal-fired generation and deprive the grid of essential reliability attributes that coal provides.*** EPA projects that just 58 gigawatts (GW) of coal-fired generation would remain by 2030 and an almost meaningless amount would remain by 2035. For perspective, the coal fleet today totals roughly 190 GW and provides approximately 20 percent of the nation's electricity. Coal-fired generation has one of the highest accredited capacity values, a measure of dependability when electricity demand peaks, and the coal fleet provides essential reliability services and other reliability attributes such as fuel security. Coal retirements will deprive the grid of attributes that are necessary to keep the lights on, especially during extreme weather, and will increase reliance on electricity resources that cannot provide these same reliability attributes.

- ***The premature shutdown of coal plants will exacerbate the already dire prospect of electricity shortages and other reliability problems.*** The Federal Energy Regulatory Commission (FERC), North American Electric Reliability Corporation (NERC), and grid operators have already raised serious concerns that the enormous number of coal retirements (totaling 130 GW nationwide since 2011 plus another 80 GW of announced retirements by 2030) could cause electricity shortages across broad geographic regions, especially during extreme weather. Furthermore, the rapid pace of coal plant retirements is especially alarming because EPA's proposal favors increased reliance on non-dispatchable intermittent resources that are not yet able to provide the same reliability attributes that coal provides.

- ***EPA has failed to evaluate the reliability impacts of its Carbon Proposal.*** One major shortcoming is the Agency examined "resource adequacy" but not "reliability." EPA defines resource adequacy as providing "adequate generating resources to meet projected load and generating reserve requirements." However, EPA's Integrated Planning Model (IPM) is designed to not project a shortage of resources because the model simply adds enough resources to avoid a shortage. If these theoretical resources that exist in the model are not built in the real world, the result is resource *inadequacy*. There are many reasons to question whether these additional resources can actually be built in the real world in time to maintain resource adequacy.

  EPA defines reliability as the "ability to deliver the resources to the loads, such that the overall power grid remains stable." However, the deliverability of electricity was not analyzed by the Agency in its modeling, even though EPA says that "resource adequacy ... is necessary (but not sufficient) for grid reliability." To address this major shortcoming, EPA must conduct a meaningful evaluation of the impacts of the Carbon Proposal on *both* resource adequacy and electric grid reliability.

  FERC has scheduled a Reliability Technical Conference on November 9 to discuss issues related to the reliability of the bulk power system. One of the topics is the impact of the proposed Carbon Rule on reliability. Because the conference will occur after the August 8 deadline for filing comments, America's Power is providing advance notice that we intend to file supplemental comments that will further explain and underscore the importance of EPA conducting a meaningful analysis of both resource adequacy and reliability.[2]

- ***To conduct a meaningful reliability assessment, the Agency must correct major technical flaws with its modeling.*** One major flaw discussed below is that IPM relies on unrealistic modeling assumptions regarding the large amounts of wind, solar, and other resources that could actually come online in the reference case due to the financial incentives provided by the Inflation Reduction Act (IRA). This problem alone leads to a false projection of coal-fired generation that would be forced to retire in EPA's reference case. Basically, EPA's unrealistically large projections of coal retirements in the reference case conceal the substantial reliability impacts the Proposed Rule would likely have on the grid because IPM does not model or otherwise consider those impacts.

- ***The Proposed Rule contains many major legal flaws that are fundamental to the proposed framework for regulating CO_2 emissions under section 111 of the CAA.*** These legal flaws include the following:

  - EPA's regulatory mandate to retire and reduce utilization of existing coal-fired generating capacity violates the U.S. Supreme Court's prohibition against generation shifting;
  - EPA's proposal to restructure the nation's electricity grid by attempting to eliminate a major source of the nation's electricity violates the major-question doctrine;
  - EPA's proposed framework to subcategorize existing coal-fired EGUs by retirement date (such as 2032, 2035, and 2040) conflicts with the express requirements of the CAA, which only authorizes EPA to subcategorize by physical or operational attributes, such as "classes, types, and sizes within categories;"[3]
  - The proposed CO_2 performance standards for coal-fired EGUs are illegal because they are based on many "outside the fence" measures that are beyond the control of EGU owners and operators; and
  - The Proposed Rule violates several other major legal requirements, such as those relating to EPA's adoption of technology-forcing standards that are impossible to achieve nationwide and that will result in the redefinition of the "source."

- ***The Proposed Rule contains many major technical deficiencies,*** including those relating to the infeasibility of meeting a 2030 compliance deadline and the Agency's failure to demonstrate that carbon capture and storage (CCS) is adequately demonstrated at commercial scale for coal-fired EGUs and that co-firing natural gas at a level of 40 percent is feasible for affected coal-fired EGUs. Detailed technical analysis[4] prepared on a wide range of economic and technology issues that discuss the many deficiencies of EPA's proposed "best system of emission reduction" (BSER) determinations for affected coal-fired EGUs are attached and referred to throughout the following comments to further highlight those flaws.

Each of these legal flaws and technical deficiencies must be corrected before the Agency can move forward. Furthermore, given that these legal flaws require major structural revisions to the Carbon Proposal, EPA has no choice but to start over in the development of an entirely new proposed rule that addresses these flaws.

Detailed Comments on the Carbon Proposal

1. The Proposed Rule would be a de facto ban on coal-fired power generation.

One of many fundamental problems with the Proposed Rule is that it would effectively mandate the retirement of the existing coal fleet that plays a critical role by ensuring an adequate and reliable supply of affordable electricity for the bulk power grid. Despite EPA's claims to the contrary regarding the Carbon Proposal providing flexible implementation of the CO_2 control measures over long-term planning horizons, the overall framework of the Proposed Rule leaves existing coal-fired EGUs with essentially only two compliance options. One is to retire the unit by 2032. The other is to limit the unit's annual capacity factor to 20 percent and retire the unit by 2035.

By contrast, the other two compliance options are not realistically viable alternatives. Those two alternatives allow an affected coal-fired EGU to operate beyond 2035 only if the unit co-fires 40 percent natural gas or installs and uses CCS that achieves a 90 percent CO_2 capture level by 2030. As discussed below in greater detail, both of these compliance options are infeasible to achieve by the mandated 2030 deadline and are prohibitively expensive to implement.

The effect of this highly inflexible and prescriptive regulatory scheme is to mandate the shutdown of virtually all existing affected coal-fired generation by 2035 given that the two compliance options for operating beyond 2035 are not realistically viable compliance pathways for almost the entire coal fleet. The Agency's own modeling analyses, in fact, confirm this outcome. According to EPA's own projections, all conventional coal-fired capacity operating without CCS retires by 2035 with only 12 GW of existing coal-fired generation operating with CCS remaining in 2035. In addition, EPA projects only 1 GW of coal-fired generation would co-fire with 40 percent natural gas in 2030 and 2035.

2. EPA has failed to evaluate the electric grid reliability impacts of the Carbon Proposal.

The new CAA regulatory framework being proposed by EPA must be firmly rooted in realistic assumptions and accurate projections regarding its regulatory and electric reliability impacts on the electric power sector. Unfortunately, EPA falls short in its evaluation analyzing such impacts of the Proposed Rule. The discussion below identifies the major shortcomings of EPA's modeling analysis and outlines the steps that EPA should take to conduct a comprehensive and robust reliability assessment that fully examines the significant risks of the Carbon Proposal, in conjunction with the other EPA rules, to electric grid reliability.

Reliability risks. The nation's power sector is undergoing a challenging transition as the electricity grid's resource mix is shifting towards more wind and solar power, and dispatchable generation—especially coal—is being retired. So far, some 130 GW of coal-fired generation have retired since 2011.[5] In addition, electric utilities have announced plans to retire another 80 GW of coal-fired generation by 2030.[6] The ongoing retirement of dispatchable generation has caused NERC officials and grid operators to issue warnings about the possibility of electricity shortages, especially during times of extreme weather.[7]

Notably, major concerns regarding the electric reliability impacts of these retirement trends were the focus of two recent hearings held by the Senate Committee on Energy and Natural Resources.[8] In the first hearing, FERC Chairman Willie L. Phillips, as well as Commissioners James Danly and Mark C. Christie, clearly described the growing risks of current and future retirements of dispatchable thermal generating capacity.

Commissioner Danly, for example, warned of "the impending, but avoidable, reliability crisis" caused by "public policies that are otherwise designed to promote the deployment of non-dispatchable wind and solar assets or to drive fossil-fuel generators out of business as quickly as possible."[9] Similarly, Commissioner Christie explicitly warned about a "looming ... reliability crisis" if "the far too rapid subtraction of dispatchable resources, especially coal and gas" continues unabated.[10] Chairman Phillips also stated during the hearing that he is "extremely concerned when it comes to the pace of retirements that we are seeing of generators that are needed for reliability on our system." He went on to say that "NERC and the grid operators have warned about this" and that "this is something that we have to keep a careful eye on."[11] A similar warning on the increased risks to the stability of the electric grids was echoed in a second Committee hearing[12] by the Chief Executive Officers of NERC and PJM Interconnection, L.L.C.[13]

Reliability impacts. There is a compelling need for EPA to evaluate the reliability impacts of the Proposed Rule, which is one of six major rules that EPA is currently implementing or developing. The impacts of the Carbon Proposal, in combination with these other rules, will further exacerbate electric grid reliability risks by causing even more coal retirements of dispatchable coal-fired generating capacity.[14]

Although EPA has used its IPM modeling to project the impacts of the Carbon Proposal on the coal fleet and electricity markets,[15] the Agency's modeling analysis results are not sufficient to evaluate electric grid reliability impacts of the Proposed Rule. This shortcoming is clearly evidenced by the fact the IPM modeling focuses on forecasting economic and certain power sector impacts but not reliability impacts of the Carbon Proposal. Most notably, for example, the Agency acknowledges that the future electricity supply projected in the reference case "is assumed to be adequate and reliable," even though this assumption is at odds with warnings from electricity officials about the increasing risks to resource adequacy and grid reliability.[16]

The coal fleet is projected to total approximately 188 GW this year according to U.S. Energy Information Administration (EIA) under its reference baseline case. By contrast, EPA's reference case projects that the coal fleet will be reduced in size to 102 GW in 2028, 72 GW in 2030, and 51 GW in 2035.[17] Because the future coal fleet is projected to be much smaller in EPA's reference case, there is a much smaller amount of coal-fired generation remaining to be impacted by the Proposed Rule.

Therefore, EPA projects the proposed Carbon Rule will cause the retirement of only 13 GW of coal in 2030 and 33 GW in 2035.[18]

EPA projections. According to the preamble to the Proposed Rule, "EPA has carefully considered the importance of resource adequacy and grid reliability in developing these proposals and is confident that these proposed NSPS and emission guidelines . . . can be successfully implemented in a manner that preserves the ability of power companies and grid operators to maintain the reliability of the nation's electric power system."[19]

EPA's assessment is inaccurate and misleading regarding the potential impacts of the Carbon Proposal on grid reliability. Furthermore, EPA cannot on its own reach such conclusions since the Agency lacks the expertise on which to make such a strong declaration. Rather, such EPA conclusions about grid reliability impacts can only be made in careful and detailed consultation with FERC, DOE, NERC, and grid operators.

One fundamental shortcoming of EPA's assessment is that the Agency only evaluates "resource adequacy" but not "reliability." As EPA itself correctly recognizes, "resource adequacy . . . is necessary (but not sufficient) for grid reliability."[20] This is the case because resource adequacy is focused only on ensuring the availability of "adequate generating resources to meet projected load and generating reserve requirements in each power region."[21] By contrast, "reliability" is much broader term that "includes the ability to deliver the resources to the loads, such that the overall power grid remains stable."[22]

We agree with EPA that resource adequacy and reliability are not the same thing. The problem with the Proposed Rule is that EPA has failed to follow through and complete a full electric reliability assessment (consisting of both a resource adequacy and reliability evaluation). In fact, the Agency has not even conducted any type of analysis or modeling regarding the reliability impacts of the dispatchable generation retirements in the reference case. Rather, EPA only used IPM to analyze resource adequacy (but not reliability) under the Proposed Rule.

According to EPA, IPM is "designed to ensure resource adequacy."[23] The model projects resource adequacy in the future "either by using existing resources or through the construction of new resources."[24] In other words, the model adds enough new resources to ensure there is sufficient electric generating capacity in the future. According to the documentation for IPM, "the model determines the location and size of the potential units to build."[25] However, there is no assurance that future resources added by EPA's model will actually be built. Given the notorious difficulty of building new electric transmission lines, the same can be said of new transmission added by the model.

Without knowing the reliability impacts of retirements under the reference baseline, it is simply impossible for EPA to make any accurate assessments regarding the reliability impacts of even an additional modest amount of dispatchable retirements (along with the many other ways that the grid would be restructured) under the Proposed Rule.

3. EPA must correct major technical flaws with its modeling analysis.

Other fundamental shortcomings with the IPM analysis are EPA's unrealistic modeling assumptions and faulty logic that conceal the major potential energy repercussions and adverse impacts of the Carbon Proposal on the electric power sector.

For example, EPA's analysis is based on unrealistic modeling assumptions regarding the large amounts of wind, solar, and other clean energy that could actually come online in the reference case over the next 15 years due to the IRA financial incentives. This assumption is reflected by the fact that EPA's modeling effectively allows for the instantaneous construction of transmission to "solve for the optimal mix of generation and transmission additions to meet capacity and energy needs."[26] Due to the IRA financial incentives along with the assumed instantaneous construction of transmission lines, EPA forecasts nearly 650 GW of additional renewable capacity coming online and operating by 2040. Based on EPA's modeling analysis, this increase is a quadrupling of current renewable generating capacity.[27]

In so doing, the EPA forecast overlooks the immense construction challenges facing the electric power sector in building out such extraordinarily large amounts of renewable energy resources. These challenges include lengthy delays due to permitting, National Environmental Policy Act (NEPA) and other environmental reviews, as well as the inevitable delays due to supply chain and many other project-specific construction difficulties that can typically occur during the development of major transmission projects. In addition, EPA ignores the requirements for domestic content and prevailing labor wages and apprenticeship requirements that could substantially limit the availability of the federal financial incentives for renewable energy deployment. All of these anticipated delays and challenges call into question the achievability of EPA's projected energy transformation. One modeling analysis by Princeton University's REPEAT Project concluded that about 80 percent of the IRA's potential emission reductions through renewable energy deployment would not materialize without reforms that enable an accelerated transmission buildout.[28]

EPA therefore mistakenly claims that the Proposed Rule will have minimal impacts on the electricity grid due to the small amounts of incremental coal-fired generation (i.e., 13 GW in 2030 and 33 GW in 2035) that would be forced to retire under the projected reference baseline. A more realistic forecast of the reference baseline means most likely a significant reduction in the amount of coal-fired generation that could actually retire over the next 15 years. This reduction in baseline coal retirements translates into a corresponding increase in the amount of existing coal-fired generating capacity that remains online and therefore could be impacted by the Proposed Rule. EPA should therefore establish a more realistic assessment of coal retirements in the reference baseline, which would otherwise be missed by the EPA reliability assessment.

It is not sufficient for EPA to downplay concerns about potential reliability problems by making reference to "significant design elements that are intended to allow the power sector continued resource and operational flexibility, and to facilitate long-term planning ."[29] Similarly, EPA cannot side-step its responsibilities for examining electric grid reliability impacts by indicating its plan to consult with DOE, FERC, grid operators, and stakeholders in the future as a solution to assure electric grid reliability during this major restructuring of the electric power sector.[30]

Rather, EPA should take notice of the many warnings being issued by FERC, NERC, and grid operators (as noted above) and not move forward with its aggressive regulatory proposal until it conducts a comprehensive and robust assessment of the proposal. Furthermore, EPA should perform this assessment in consultation with DOE, FERC, NERC, and the grid operators. The upfront evaluation of these reliability risks is highly preferable to the establishment of a retroactive process of addressing electric reliability.

4. ***EPA's mandate to retire and reduce utilization of coal-fired generating capacity violates the U.S. Supreme Court prohibition against generation shifting.***

The U.S. Supreme Court in *West Virginia v. EPA* expressly rejected generation shifting as a compliance option when setting performance standards under section 111 of the CAA.[31] In so doing, the Court thereby barred EPA from adopting performance standards that have the effect of forcing existing coal-fired EGUs to either retire or reduce their production (or utilization) levels, instead of installing the "best system of emission reduction" (BSER) on the affected source. Compliance with such a regulatory mandate to retire or reduce the utilization levels violates the Supreme Court's *West Virginia* prohibition because compliance can be achieved only by shifting generation from coal to natural gas and renewable energy resources. In the case of the Clean Power Plan (CPP), the Supreme Court determined such generation shifting was prohibited by a CPP regulatory regime that would reduce national electricity generation from coal-fired EGUs from 38 percent in 2014 to 27 percent by 2030.[32]

EPA's proposed regulatory mandate to retire all conventional coal-fired capacity, as described above, clearly runs afoul of the Supreme Court's prohibition in *West Virginia*. Furthermore, the imposition of a 20 percent annual capacity limitation on coal-fired EGUs retiring by 2035 is also another impermissible EPA mandate to force generation shifting from coal to gas or renewable energy. This is clearly evidenced by the fact the average capacity factor of coal-fired EGUs in 2021 was 49 percent,[33] with 67 percent of those existing units being larger than 0.5 GW.[34] A 20 percent capacity-factor limitation will therefore require the shifting of electric generation from coal-fired units to natural gas and renewable energy resources.

On a broader national energy scale, the shifting of generation away from coal to renewable energy resources is clearly documented in EPA's own modeling analysis of the Proposed Rule. One clear indicator is EPA's IPM modeling analysis, which shows that retirements and production curtailments of existing coal-fired generation would achieve virtually all of the CO_2 emissions reductions from these affected units under the Proposed Rule.

For example, the updated 2030 IPM model baseline forecasts 72.7 GW capacity and 354.3 terawatt-hours (TWh) of coal-fired generation in the year 2030 when the proposed performance standards would take affect for existing affected coal-fired

EGUs. By contrast, EPA forecasts that coal-fired generating capacity in 2030 drops by 13.7 GW or 19 percent below the reference baseline to 59 GW. Similarly, EPA's IPM modeling shows that coal-fired generation drops by 44 percent to 196.9 TWh based on the forecast that 55 percent or 40.2 GW of coal-fired capacity elects to run at an annual capacity factor of less than 20 percent.

This result occurs based on the EPA's modeling results forecasting that the majority of the existing coal-fired EGU capacity does not co-fire with natural gas or add CCS but rather opts to retire or run at less than a 20 percent capacity factor and then retire by 2035. In the case of the CCS compliance option, only 17 GW of existing baseline coal-fired generating capacity elects not to retire, but instead to deploy CCS systems by 2030.

This regulatory framework is contrary to the way that the section 111 framework is intended to work. Under the statutory framework, EPA makes BSER determinations regarding the control measures (such as 40 percent natural gas co-firing and CCS with 90 percent capture) that would then apply to the affected sources. Instead, EPA's most recent IPM modeling results show that virtually all of the CO_2 emissions reductions from the EGU source category are achieved by a dramatic reduction in coal-fired capacity and generation in response to stringent performance standards that are technically and economically infeasible to achieve by 2030. By contrast, virtually none of the CO_2 emission reductions from the EGU source category is achieved by applying the BSER control measures to affected coal-fired units—which is the intended regulatory framework under section 111 of the CAA.

This proposed regulatory framework is effectively generation shifting—which is expressly prohibited by the Supreme Court in *West Virginia*. As a result, EPA has no choice but to withdraw the Proposed Rule and begin again in developing an entirely new regulatory proposal that does not violate the Court's generation shifting prohibition.

5. EPA's proposal to restructure the electric power sector violates the major question doctrine.

EPA's proposal would have profound impacts on the electric power sector, and in effect, redefine how electricity is generated and delivered through the power grid in the United States. Compliance with EPA's proposed performance standards (which includes mandated retirement dates for almost all existing coal-fired EGUs as discussed above, thereby eliminating a major source of the nation's electricity) will require the deployment of new, large-scale energy infrastructure that will take decades to develop and build out. This kind of transformative restructuring of the power sector without explicit authority from Congress violates the major questions doctrine as enunciated and confirmed by the Supreme Court in *West Virginia v. EPA*.[35]

In the *West Virginia* case, the Supreme Court held that the CPP was illegal because it violated the major question doctrine due to EPA's attempt to use CAA section 111(d) to "substantially restructure" the U.S. power grid.[36] Specifically, the Court concluded that EPA had adopted in the CPP "a regulatory program that Congress had conspicuously and repeatedly declined to enact itself."[37] In light of those circumstances, the Court rejected EPA's statutory interpretation that section 111(d) conferred broad authority to adopt the CPP regulatory program that had such widespread impacts on the electric power sector by redefining how electricity is generated and delivered through the grid.[38] Accordingly, the Court held that "it is not plausible that Congress gave EPA the authority to adopt on its own such a regulatory scheme in section 111(d). A decision of such magnitude and consequence rests with Congress itself, or an agency acting pursuant to a clear delegation from that representative body."[39]

The same transformative impacts would result from the implementation of EPA's current Carbon Proposal. This is evidenced by the fact that the overall regulatory impact of the Proposed Rule is not much different than what the power grid faced under the CPP. In that rule, EPA set CO_2 performance standards based on "building blocks" for efficient generation, increased use of natural gas in place of coal-fired generation, and similar generation shifting from fossil-fueled generation to renewable energy generation.[40] Importantly, due to the stringency of the CPP performance standards, compliance could be achieved only by the reduced utilization or shutdown of existing coal-fired generation while subsidizing the development and use of natural gas and renewable energy generating resources.[41]

In a manner similar to the CPP, the overall objective for the current Carbon Proposal is to transform the electric power sector by imposing aggressive reductions in CO_2 emissions from the EGU source category. In particular, the Proposed Rule, if adopted, would transform the electric power sector in a manner similar to the aggressive transformation of the electric power sector that EPA had sought to advance in the CPP. That energy transformation entailed the establishment of a national system of carbon capture, transport, and sequestration of CO_2 as well as the rapid buildout of a national system of hydrogen production using low- or no-carbon generation to power electrolysis, with transportation and storage hubs to enable co-firing of this low-emitting hydrogen. Furthermore, as discussed above, it would require retirement and reduced utilization of fossil-fueled generation as well as the shifting of generation to renewable energy resources—all of which the Supreme Court expressly prohibited in *West Virginia* decision.

Moreover, just as in the case of CPP, EPA again relies on the same general language in CAA section 111(d) to support its claim for legal authority to establish such transformative requirements. However, that statutory language is not sufficient. As the Supreme Court explained in the *West Virginia* decision, section 111(d) is "a vague statutory grant [that] is not close to the sort of clear authorization required" to adopt such transformative regulatory program.[42] Despite EPA's efforts to distinguish this current proposal from the CPP (by arguing that "systems of emissions reduction like fuel switching, add-on controls, and efficiency improvements fall comfortably within the scope of prior practice as recognized by the Supreme Court") the overall effect of these "systems" is a fundamental shift of power generation from certain segments of the power sector to other generating units and fuels.[43] To correct this fundamental flaw, EPA must develop an entirely new framework for the regulation of CO_2 emissions from the EGU source category under section 111 of the CAA.

6. The Carbon Proposal contains other major legal flaws that EPA must correct.

The Proposed Rule contains other major legal flaws that are fundamental to the overall proposed framework for regulating CO_2 emissions from new and existing fossil fuel-fired EGUs under section 111. Each of these legal flaws, which are discussed below in detail, must be corrected before the Agency can move forward with the adoption of a final rule. Furthermore, given that these legal flaws require wholesale revisions to the Carbon Proposal, EPA has no choice but to start over in the development of an entirely new proposed rule that addresses each of the following legal flaws.

Subcategorization. EPA lacks the authority to subcategorize the source category of existing affected coal-fired EGUs by the retirement date of each unit. Rather, the statute only authorizes EPA to subcategorize the EGU source category by physical characteristics, specifically "classes, types, and sizes within categories"[44] for the purposes of setting performance standards for new sources under section 111. This means that EPA is barred—as a matter of law—from establishing different subcategories of affected coal-fired EGUs based on whether the unit will retire by a specific date, such as 2032, 2035, or 2040.

The illegality of the Agency's proposed approach is clearly evidenced by the fact that EPA has lumped all classes, types, and sizes of coal-fired units together and only then divided them into the proposed subcategories by the retirement date of each unit (which is not a factor enumerated in the statute). Furthermore, each of the four EGU subcategories will consist of coal-fired units with widely disparate physical and operating characteristics in contradiction to the statute.[45] This approach is contrary to the statute, which requires EPA to differentiate among coal-fired units within the EGU source category in accordance with the statutory criteria, such as the size of the unit, the type of coal combusted, the boiler technology used for combusting the coal, other physical attributes of the generating facility, and how the unit is operated (such as the unit's capacity factor).

This statutory conflict is further evidenced by the fact that EPA will not know the number and composition of each existing coal-fired EGU subcategory at the time that EPA issues the final Carbon Rule. In effect, the Agency will be making its subcategorization classifications "blind," without regard to any of the physical characteristics of units within each subcategory (such as age, boiler size and type, capacity factor, and pollution controls). Rather, the Agency will not be able to define each of the four subcategories until at least two years after the adoption of a final rule when states submit to EPA their final implementation plans that establish enforceable retirement deadlines for each affected coal-fired EGU within their jurisdiction.

Neither adequately demonstrated nor feasible. CCS does not meet the statutory requirement for BSER under CAA section 111(a)(1), which requires that the control technology must be "adequately demonstrated" as well as that the performance standard must be technically and economically feasible. A detailed discussion is provided below documenting EPA's failure to comply with this fundamental threshold statutory requirement for regulating CO_2 emissions from existing coal-fired EGUs under section 111(d). Furthermore, even if CCS technologies were adequately demonstrated (which is not the case), the full-scale commercial application of this control technology is not yet able to achieve EPA's proposed CO_2 performance standard of a stringent capture level of 90 percent on the entire flue gas stream of a coal-fired EGU on a continuous annual basis. Finally, the Carbon Proposal falls short of demonstrating the availability of CCS due to several other important constraints that preclude the deployment of CCS, including those imposed by geographic constraints, access to sufficient water supplies, and difficulties in building out the necessary supporting infrastructure.

"Outside the fence." The Proposed Rule establishes a BSER for CCS that assumes the deployment of CCS infrastructure based on many "outside the fence" factors that are beyond the control of electric utilities.[46] As discussed in greater detail below, these factors relate to the considerable challenges on the following matters that must be developed offsite of the EGU facility:

- Securing Underground Injection Control (UIC) Class VI permits that are necessary for the injection of the CO_2 emissions captured from the affected coal-fired EGU;
- Obtaining ownership of the pore space that is necessary for the long-term storage of the CO_2 injected into the geological formation;
- Development, siting, permitting, and construction of the pipeline necessary for transporting the CO_2 to the sequestration site, which can be a hundred or more miles away; and
- Addressing potential concerns with accounting for and ensuring the long-term storage of the injected CO_2 in the underground geological formations.

Moreover, the proposed standards can be met only if electric utilities subsidize the construction of a national system of CO_2 pipelines and related infrastructure. If they do not (or cannot, because permitting and constructing this national infrastructure proves infeasible), the only option is for electric utilities to reduce utilization or retire their existing coal-fired generating units which is prohibited as a BSER determination.

Technology-forcing. Neither the CAA nor court rulings cited by EPA support the Agency's proposed determination that CCS is BSER for existing coal-fired EGUs. In effect, EPA would be imposing on existing affected coal-fired EGUs a technology-forcing standard that requires the installation of emerging new add-on control technology that still has not been retrofitted on existing EGUs at a full, commercial scale as evidenced by the Petra Nova and Boundary Dam CCS Projects (discussed below).

EPA lacks the authority to establish a technology-forcing performance standard based on future projections regarding the achievability and cost of CO_2 emission reductions. While the Proposed Rule notes that court decisions have confirmed EPA's authority to make reasonable projections on the use of control technologies not "in actual routine use," this authority is limited to rulemakings in which the Agency is setting performance standards for *new* stationary sources under section 111(b) of the CAA. Neither the statute nor court rulings cited by EPA support the claim that the

Agency also has the authority to adopt a technology-forcing performance standard for *existing* coal-fired EGUs under section 111(d). These court rulings are inapplicable and therefore do not allow EPA to set a CO_2 performance based on an emerging control technology for which there is no coal-fired EGU operating with CCS at commercial-scale and deep underground sequestration. Moreover, this interpretation was confirmed in a recent court determination in which the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) ruled that the CAA must "explicitly require[ ] the EPA to . . . adopt a technology-forcing approach."[47] Nothing in the statute authorizes EPA to do so in setting performance standards for existing EGUs under section 111(d).[48]

Projections of BSER. Contrary to the statute, EPA is making BSER determinations for many of the subcategories based not on what is adequately demonstrated as technically and economically feasible now, but on what the Agency is forecasting will be adequately demonstrated and feasible in the future.[49] In the same way that EPA lacks authority to adopt technology-forcing performance standards, the Agency cannot adopt standards which are impossible to implement until ten or 15 years after the promulgation of a final rule. Moreover, EPA's proposed approach for phasing in the control requirements over such a long timeframe is contrary to the way EPA has traditionally established and implemented performance standards for other source categories under section 111.[50]

Subsidization of projects. As discussed in greater detail below, the Energy Policy Act of 2005 (EPAct05) bars EPA from setting performance standards based on CCS demonstration projects that are subsidized by the clean coal technology development programs. When those federally funded projects are stripped away from the BSER analysis in the Proposed Rule, EPA is left with virtually no CCS projects demonstrating technical feasibility for coal-fired power plants. In addition, the fact that every CCS demonstration project so far undertaken was heavily subsidized by federal funding further underscores the fact the CCS is not yet economically feasible.

Nationwide compliance. Any performance standard set under section 111 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[51] 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."[52]

The Proposed Rule fails to comply with this fundamental requirement. The proposed performance standards for both the CCS and 40 percent co-firing with natural gas are illegal because all affected coal-fired EGUs nationwide cannot meet the applicable compliance requirements.

For example, some coal-fired units are located in certain areas of the country that lack geological formations for the injection and long-term storage of the captured CO_2. Since not all existing coal-fired EGUs nationwide can install and operate with CCS, EPA cannot adopt a CCS performance standard that applies nationwide.

Similarly, it would be infeasible for existing coal-fired units in many areas of the country to gain access to reliable, firm supplies of natural gas in substantial amounts. Since not all coal-fired EGUs nationwide can co-fire with 40 percent natural gas, EPA cannot impose a 40 percent co-firing performance standard nationwide. Given the additional pipeline capacity needed for 40 percent co-firing and the typical recent permitting delays for the buildout of new natural gas infrastructure, it is unrealistic to think this buildout can be accomplished by EPA's proposed compliance date of 2030.

Cooperative federalism and state implementation plans. The CAA establishes a program of cooperative federalism, which expressly provides states—not EPA—with the right under section 111(d) to "establish" and "apply" performance standards and to "take into consideration, among other factors, the remaining useful life of the existing source to which [a] standard [of performance] applies."[53] Furthermore, this program of cooperative federalism gives states the primary role for such regulation of existing affected EGUs under the CAA and leaves the Agency in the secondary role of performing the "ministerial function of reviewing [state plans] for consistency with the Act's requirements."[54] The Proposed Rule violates this framework by establishing a highly prescriptive and inflexible framework for state implementation of the federal emission guidelines.

A related implementation problem is that the Proposed Rule requires states to adopt and submit to EPA their implementation plans within two years after the final rule becomes effective. This means that electric utilities will have no choice but to make their decisions on retirement within this same two-year period so that the states reflect in their implementation plans federally enforceable commitments to retire those units. This timeframe will no doubt drive early retirement decisions, as there will be no certainty on the buildout of national systems for deployment of clean hydrogen and infrastructure or for the deployment of CCS systems at particular coal-fired EGUs.

7. *EPA failed to establish performance standards for coal-fired EGUs in accordance with the requirements of section 111.*

EPA has failed to follow the statutory framework that Congress established for setting performance standards for existing coal-fired EGUs. That framework, as clearly provided in section 111, requires EPA to set federal performance standards at "achievable" levels that reflect the "best system of emission reduction . . . adequately demonstrated," while considering various factors such as cost, non-air quality health and environmental impacts, and energy requirements.[55]

When setting such performance standards under section 111, the D.C. Circuit has provided specific directions to EPA in making its determinations on BSER and "adequately demonstrated." In particular, the court has held that an "adequately demonstrated" BSER is "one which has been *shown* to be reasonably reliable, reasonably efficient" and achieves meaningful emission reductions "without becoming exorbitantly costly in an economic or environmental way."[56] In addition, the court has instructed that the Agency cannot make its BSER determination based on "mere speculation or conjecture" in those situations "where data are unavailable" regarding the performance of a control technology.[57] In effect, a BSER determination must be based on adequately demonstrated control measures that have an operational history with actual performance data that shows more than mere technical feasibility.

Furthermore, the court has provided guidance to EPA on the achievability of performance standards adopted under section 111. That guidance requires the Agency to adopt standards that are "achievable under the range of relevant conditions which may affect the emissions to be regulated,"[58] including "under most adverse conditions which can reasonably be expected to recur."[59] In addition, EPA lacks the authority to establish a technology-forcing performance standard for existing coal-fired EGUs based on future projections regarding the achievability and cost of CO_2 emission reductions with CCS.[60] EPA has failed to follow this statutory framework in developing proposed CO_2 performance standards for existing affected coal-fired EGUs for several important reasons.

First and foremost, EPA has proposed to make a BSER determination for existing coal-fired EGUs based on post-combustion CCS control technology that is not adequately demonstrated. CCS is a promising control technology that can achieve substantial reductions of CO_2 emissions from coal-fired EGUs. However, the post-control CCS technology so far has been used at only a few demonstration projects. These projects involve "first of a kind" (FOAK) applications of the control technology that are insufficient for proving CCS is adequately demonstrated for broad commercial deployment. As required under section 111, the Agency may adopt CCS (or any other control technology) only when it is demonstrated as a commercially viable technology at a utility-scale under a wide range of commercial applications and operating conditions.

Second, these FOAK projects do not demonstrate that CCS is economically feasible given the large federal subsidies that are needed to offset the excessively high costs of capturing, transporting, and sequestering the CO_2 for long-term storage in geological formations. Third, even if CCS technologies were adequately demonstrated (which is not the case), the full-scale commercial application of this control technology has never been achieved to meet EPA's proposed standard of a stringent capture level of 90 percent from the entire flue gas stream of a coal-fired EGU on a continuous annual basis.

Each of these reasons is discussed below in greater detail.

8. CCS is not adequately demonstrated for existing coal-fired EGUs.

CCS is an emerging control technology that EPA cannot consider in setting CO_2 performance standards for existing coal-fired EGUs under CAA section 111(d). To date, there have been only two full-scale applications of post-combustion carbon capture systems on coal-fired units at a full commercial scale.

As discussed below, these two FOAK applications may indicate CCS is a promising CO_2 control technology, but they fall well short of meeting the statutory standard that the technologies are "adequately demonstrated" for capturing on a commercial scale and permanently storing CO_2 at an affordable cost. Rather, those projects represent only an initial first step of the process for demonstrating the technical and economic feasibility of the CCS technology at all coal-fired EGUs nationwide.[61]

Boundary Dam CCS project. One of these two commercial applications is the Boundary Dam CCS Project that was retrofitted with a FOAK post-combustion carbon-capture system by SaskPower on an existing coal-fired EGU at its Boundary Dam Power Station in Canada.

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.

The Boundary Dam CCS Project has encountered a number of design problems. One major problem resulted from the high flue gas temperatures and particulate content that have interfered with and 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.[62] 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 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.[63] This and other problems[64] 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[65] point to design and operational problems that need to be addressed before CCS technology is shown to be adequately demonstrated.

Petra Nova CCS project. The other FOAK application of CCS is the Petra Nova CCS Project, which NRG brought online in January 2017 at an existing coal-fired unit at its W.A. Parish Power Generating Station in Texas. The Petra Nova 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. When the design capture rate can be achieved consistently, the Petra Nova Project has the capability to achieve only a 33 percent reduction in overall CO_2 emissions from Unit 8.[66] This control level is well below EPA's proposed performance standard requiring a 90 percent capture level and achieving an 88.4 percent reduction in the unit's existing CO_2 emission rate.

Like the Boundary Dam CCS Project, NRG has encountered numerous design and operating problems. The Petra Nova Project has been unable to demonstrate the integration of the thermal (parasitic) load requirements for operating 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. This design feature is unique to the Petra Nova demonstration project and cannot be generally replicated at other coal-fired EGUs nationwide. Furthermore, the Petra Nova Project does not demonstrate the integration of the thermal load of the carbon capture technology into the boiler steam cycle—which is a critical element of demonstrating the viability of post-combustion CCS technologies.

Need for additional projects. Finally, it should be stressed that the Boundary Dam and Petra Nova Projects only tested the feasibility of two possible FOAK applications of a post-combustion CO_2 capture with relatively small amounts of flue gas streams from existing coal-fired EGUs. Neither project demonstrated the full-scale commercial application of post-combustion carbon capture technologies on coal-fired EGUs. The completion of additional demonstration projects is therefore still needed to ensure the workability of the CCS technology.

The risk that a particular capture technology may not work is neither theoretical nor negligible. A case in point is the Kemper Project.[67] Originally scheduled to be operational by May 2014, with an estimated cost of $2.4 billion, the Kemper Project encountered significant delays and complications, ultimately resulting in expenditures surpassing $7.5 billion by June 2017. In an effort to manage escalating costs, state regulators ultimately ordered the power plant to burn natural gas instead of coal and operate without CCS technology.

9. Other small-scale pilot projects fail to prove CCS is adequately demonstrated.

In support of its proposed BSER determination, the Proposed Rule also refers to various small-scale pilot projects involving the application of CCS at both electric utility and industrial facilities. Notable examples include projects capturing CO_2 from a slipstream of flue gas from the Warrior Run plant in Maryland and the Shady Point plant in Oklahoma. These and other small pilot projects cited by the Carbon Proposal are insufficient for demonstrating that CCS is adequately demonstrated as a commercially viable technology at utility-scale for the following reasons.

First, all of these demonstration projects involved the small-scale application of CCS on a small slipstream portion of the flue gas stream. As a result, CO_2 was captured from only ten percent of the slipstream for the Warrior Run plant (totaling about 110,000 metric tons of CO_2 per year) and five percent for the Shady Point plant (totaling about 66,000 metric tons of CO_2 per year).[68] This is an order of magnitude less than the high volumes of CO_2 emissions that must be captured to achieve

90 percent capture levels that a large coal-fired EGU must achieve on the entire flue gas stream under Proposed Rule.

Second, none of the small-scale pilot projects involved the transport and sequestration of the captured CO_2 emissions in an underground geological formation. Rather, the CO_2 emissions from these projects were sold to the food processing and beverage industries.[69] Third, these small demonstration projects were not operated continuously on an annual basis, as would be required to meet the proposed CCS performance standard. Rather, these demonstration projects are typically run for no more than eight hours per day during daylight and could be easily shut down for repairs, maintenance, or when the need for power generation is low. Similarly, if technical issues or malfunctions should arise, these demonstration projects can easily shut down for repairs or other maintenance.

All of these considerations are clear indicators that EPA cannot rely on these small-scale projects to make a BSER determination that CCS is adequately demonstrated. Rather, they indicate that additional demonstration projects are necessary to demonstrate the effectiveness, reliability, and affordability of CCS in full-scale utility applications for a variety of coal-fired EGU facilities under real-world operating scenarios.

10. CCS is not economically achievable because the costs are excessively and prohibitively high.

Even if 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 existing coal-fired EGUs.[70] As noted above, the CAA requires EPA to take into account the cost of achieving the required emission reductions, and the Agency has an obligation to eliminate from consideration 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,"[71] "greater than the industry could bear and survive,"[72] "excessive,"[73] or "unreasonable."[74] 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."[75]

Costs for specific projects. Very high costs were incurred by Boundary Dam and Petra Nova, the first wave 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 five times the amount that EPA estimates for a CCS retrofit project at an existing coal-fired power plant.[76] 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.[77] 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.[78]

In addition, the project relies on revenue from sale of the captured CO_2 for enhanced oil recovery (EOR).[79]

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. Just like Boundary Dam, the reported capital costs were also much higher than EPA's current estimates for CCS retrofits. According to EIA, the retrofit cost was reported to be $1 billion, or $4,200/kW, which is about 90 percent higher than EPA's estimate of $2,222/kw for a 400 MW unit as reflected in a Sargent & Lundy technical report.[80]

Before CCS can be considered a cost-effective BESR control technology, an additional wave of demonstration projects will be necessary to build on the lessons learned from this first wave of projects, including to increase efficiency and reduce capital and operational costs of CCS technology.

FEED studies. EPA's cost estimates for the carbon capture system in the Sargent & Lundy report are far below not only the Boundary Dam and the Petra Nova Projects but also the detailed cost estimates developed for the FEED studies for six coal-fired EGUs.[81] The cost estimates for the FEED studies provide a more authentic estimate of capital costs that would likely be incurred, as compared to EPA's cost estimate, which is based on projections for a "hypothetical" 400 MW model plant that do not account for any site-specific factors. By contrast, the FEED study estimates are a more authentic and accurate forecast of costs because they are based on a transparent compilation of the estimated costs for each component of a particular CCS project based on an engineering analysis of that project component.[82]

As explained in the CCS Technical Report prepared for America's Power, the average capital cost reported in these eight FEED studies (excluding the highest and lowest estimated values) was $3,198/kW, which is 44 percent higher than EPA's projected estimated cost of CCS derived from the Sargent & Lundy report. It is important to note that a 44 percent premium is a conservative estimate of just how unrealistically low the EPA cost estimate is because the FEED study cost estimates are limited to the capital costs for CO_2 capture, compression, and preparation for transport from the fence line of the facility. The FEED study cost estimates do not include capital costs for the transport of CO_2 to the injection site, as well as all of the costs for injection and assuring long-term storage of the injected CO_2, which can be quite substantial.[83]

Similar problems arise regarding EPA's estimates of levelized costs to avoid CO_2 emissions. EPA's projected levelized costs substantially reduce costs by as much as $25 to $30 per ton with the IRA financial incentives included in the cost estimates.[84]

Future CCS costs. In addition to not reflecting the high costs of CCS deployment actually incurred at these two demonstration projects as well as the estimated cost for specific projects in the FEED studies, EPA makes unsubstantiated claims that CCS costs are declining and will continue to do so over the next ten to 15 years. However, as the available data points for various projects referenced above suggest, these project-specific costs remain much higher than EPA's estimates for the future CCS projects. Furthermore, even though EPA cites optimism about declining CCS cost, the IPM model results do not show large-scale deployment of CCS (in fact only 17 GW of CCS capacity by 2035) that would be necessary to improve the design, operation, and effectiveness of the capture equipment and processes for extracting the CO_2 emissions from the flue gas in the most efficient and cost-effective manner. Also, the fact that all of the projected projects would have to be concurrently developed, engineered, procured, constructed and commissioned in a short time frame would not allow for any "learning" to occur, to be shared, or to be useful in reducing costs.

Furthermore, the Sargent & Lundy technical report[85] on which EPA bases its CCS cost estimates does not provide any objective real-world support (either data cost or engineering analysis) or other plausible technical justification for its optimistic trends on declining CCS control costs. Rather, it shows a declining cost curve with only the Petra Nova project bridging the gap in costs between completed projects and announced projects.[86] In addition, the removal cost estimate of about $60/ton-CO2 removed for Petra Nova and the overall CCS cost curve cited by the S&L report were based on an unsubstantiated claim by the Global CCS Institute,[87] a non-governmental advocacy organization dedicated to promoting the deployment of CCS.[88] Reliance on the claims of such an organization is questionable given that the Global CCS Institute has a strong vested interest in projecting the financial efficacy of CCS over the long term.[89]

Other reasons for cost Increases. Studies from the Sargent & Lundy report discussed above and another technical report by the National Energy Technology Laboratory (NETL report)[90] on CCS costs and deployment, which are cited by EPA in the Proposed Rule, are also clear that cost pressures due to inflation and other economic factors are not included in their CCS cost estimates. In fact, NETL report notes:

> The cost estimates for plant designs that include technologies that are not yet fully mature (e.g., IGCC plants and any plant with CO2 capture) use the same cost estimating methodology as for mature plant designs, which does not fully account for the unique cost premiums associated with the initial, complex integrations of emerging technologies in a commercial application. Thus, it is anticipated that early deployments of IGCC plants—both with and without CO2 capture—as well as PC and NGCC plants with CO2 capture, may incur costs higher than those reflected within this report.[91]

In addition, the S&L report contains similar statements on the exclusion of these costs, such as the following: "Escalation is not included in the estimate because all costs are provided in 2021 dollars and are not representative of recent COVID and inflation related pricing increases."[92] As such, the current costs of CCS technology are likely to be much higher than EPA estimates.

EPA also skews its analysis of levelized CCS costs by ignoring important real word realities of financing. EPA presents the levelized costs of CCS using a nominal Weighted Average Cost of Capital (WACC) of 5.59 percent.[93] This is much lower than recent typical electric utility returns on equity would suggest, ignores import risk premiums for merchant facilities and a nascent technology, and ignores the higher costs of debt that are currently being incurred with higher interest rates. While EPA might have developed its WACC calculations on financial theory, in practice the actual WACC for electric utilities and merchant generators is several hundred basis points higher than EPA's estimated levels. To have creditable cost estimates, EPA should revise its financing assumptions to present CCS levelized costs as a function of the costs currently likely to be incurred, as based on current market realities. Likewise, EPA's analysis of levelized costs of CO2 removal is also skewed, not only by the inaccurate WACC, but a failure to account for property taxes and insurance.[94]

High costs. Notably, the excessively high costs of CCS also are implicitly confirmed by EPA's own modeling of the Carbon Proposal even with EPA's unrealistically low-cost estimates for CCS just discussed above.[95] This fact is clearly evidenced by the results of the EPA modeling. Of the coal-fired generating capacity projected to be online in 2030 under the baseline reference case, 13.7 GW of coal capacity (19 percent) is projected to retire in 2032 and another 40.2 GW of coal capacity (55 percent) is modeled to run at an annual capacity factor of less than 20 percent until it retires in 2035. By contrast, the BSER measure of natural gas co-firing is only deployed 0.9 GW (1 percent) of baseline coal capacity, while CCS is deployed incrementally on only 17 GW of baseline coal capacity in 2030. This regulatory outcome shows that the vast majority of the coal-fired EGUs units online in 2030 under the baseline will not select CCS or natural gas co-firing because neither one is a cost-effective control option. Rather, they are electing to deploy the other two BSER control options for reducing generation output and retiring because CCS and natural gas co-firing are simply not cost-effective.

Comparison to SO_2 scrubbers. Finally, it is important to note that the state of current CCS technology is much more nascent today than wet scrubber technology was when a sulfur dioxide (SO_2) control mandate was put in place in 1971. At that point in time, there were three unsubsidized scrubbers controlling over 695 MW of capacity and 15 more under construction on over 3,300 MW throughout the U.S. fleet. Additionally, the use of wet scrubbers was also being adopted elsewhere in the world at that time, chiefly Japan. The use of wet scrubbers on large-scale power plants was also first demonstrated 40 years prior to widespread adoption in the 1970's, most notably in England.[96] In contrast, the CCS projects relied upon by EPA in the Proposed Rule are first of a kind, heavily subsidized slipstream projects that have experienced operational issues with nowhere near the amount of actual "in-construction" projects, as was the case with scrubbers. In addition, many CCS projects (such as Petra Nova) may rely on additional financial support from oil revenues generated from EOR projects.

11. EPA is barred from basing its BSER determination on CCS demonstration projects receiving DOE funding.

EPAct05 prohibits EPA from determining 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).[97]

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 was used at a project funded through an EPAct05 program.[98] 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.[99]

The Petra Nova CCS Project received substantial government funding from DOE under the CCPI program to construct and demonstrate the post-combustion CCS system installed to capture the CO_2 from the Parish generating unit. This means that EPA is barred from considering the performance of carbon capture in the Petra Nova Project when determining whether CCS technologies have been "adequately demonstrated" for existing coal-fired EGUs under CAA section 111(d).[100]

12. 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[101] 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."[102] 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 United States.[103]

In the preamble to the Proposed Rule, EPA presented an updated analysis of geological storage capacity in the United States. 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."[104]

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.[105] 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.[106] 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.[107]

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 United States. 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.[108] This means that at least 15 states lack, or might lack, adequate geological storage capacity necessary to support 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 United States, 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.[109] This geographic limitation provides further reason to eliminate 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.

13. *Other major barriers must be removed before EPA can set CO_2 performance standards based on CCS.*

EPA has the burden of demonstrating that all elements of CCS—capture, transportation, and storage of CO_2—have been adequately demonstrated at utility scale and ready for commercial deployment. This means it is not sufficient for EPA to determine that the technology has been adequately demonstrated for only capturing the CO_2 emissions from coal-fired power plants. These barriers and limitations must be addressed before EPA may determine that CCS is widely deployed as an adequately demonstrated emission reduction system. Notable examples of these many challenges are briefly outlined below.

CO_2 transport. In the case of CO_2 transportation, there are many issues that must be resolved to support the significant build-out of the existing CO_2 pipeline system that—so far—has been developed mainly for EOR. One key issue relates to the cumbersome process that currently exists for the siting, land acquisition, and construction of an expanded pipeline system. Another important limitation relates to the long lead times for environmental clearance (e.g., NEPA) and large capital investments that will be necessary to build this new pipeline system. All of these matters must be addressed before large volumes of CO_2 can be transported and stored in order for CCS to be considered "adequately demonstrated."

Long-term storage. Similarly, the sequestration component of CCS is in the early stages of development and clearly does not satisfy the "adequately demonstrated" criteria. This is reflected by the fact that there are no large-scale geologic storage projects integrated with power plants on a utility scale.

At this time, there are not any commercial CO_2 storage projects for deep saline storage in operation in the United States. Moreover, all CO_2 storage projects require significant federal financial support, including the Regional Carbon Sequestration Partnerships and the CarbonSAFE projects, which are both supported and administered by DOE. Given the substantial federal financial assistance and lack of a commercial CO_2 storage operation, CO_2 storage in non-EOR applications cannot be considered "adequately demonstrated" for purposes of BSER.

Operating CO_2 storage facilities in saline formations also faces significant challenges that need to be addressed before CCS is adequately demonstrated. First, the existing regulation of CO_2 injection into deep saline, permitted as Class VI injection wells under EPA's Underground Injection Control program, pose practical barriers to project development. One element of the regulatory scheme in particular—a post-injection site care monitoring period of 50 years—poses particular challenges in project development. A typical injection from a power plant may last several decades. Adding 50 years of post-injection site care has the potential to more than double the lifetime of a CO_2 injection operation. Second, the long-term liability framework for injected CO_2 remains uncertain in many areas of the country and limits the opportunity to store CO_2 in saline formations in those regions. Once CO_2 has been injected, the framework for managing the potential liability resulting from the injected CO_2 remains uncertain. Currently, a patchwork of state policies exists, leaving the uncertainty that surrounds a long-term liability of injected CO_2 unresolved.[110]

Another significant potential impediment for deep saline storage relates to the property rights for subsurface CO_2 storage (i.e., pore space). Most states lack a regulatory framework for explicitly addressing ownership, integration, and long-term indemnification of pore space for carbon storage. This lack of clarity adds to the list of obstacles necessary to overcome for any project developer to install and operate CCS.

While the considerations discussed above will vary site by site and project by project, they impact the feasibility of integrating CCS at a power plant. These challenges must be sorted out prior *to* the beginning of CCS operations because subsurface storage must be operational at all times for a CCS project. EPA must reconsider the challenges of CO_2 storage outlined here because they pose direct challenges to the feasibility of integrating CCS at a coal-fueled power plant.

14. The proposed 90 percent capture level is unachievable.

In the case of all coal-fired EGUs retiring on or after January 1, 2040, the Proposed Rule would set a performance standard mandating that these units achieve a 90 percent capture of the CO_2 in the flue gas.[111] This proposed performance is contrary to the statute that requires EPA to set a CO_2 emission limitation that is "achievable through the application of the best system of emission reduction"[112] for several reasons.

First, even if CCS was, in fact, determined to be adequately demonstrated (which is not the case), the control technology cannot necessarily achieve continuously on an annual basis a 90 percent capture level at all load levels by all affected units under the full range of operating conditions. There is a big difference between designing a CCS project that may have the capability of achieving a 90 percent capture level (which can be done) and a facility with CCS actually achieving consistently this performance level under the full range of operating conditions on an annual basis (which so far has not yet been achieved through the FOAK CCS demonstration projects). Therefore, EPA has a legal obligation to adjust the stringency of the proposed standard by lowering the CO_2 control requirement to those levels achievable "under the range of relevant conditions which may affect the emissions to be regulated,"[113] including "under most adverse conditions which can reasonably be expected to recur."[114]

Second, the courts have interpreted this statutory provision on achievability as requiring that the performance standards be achievable "for the industry as a whole" and not just for a subset of sources.[115] In the case of the Proposed Rule, EPA therefore has a legal obligation to set a CO_2 performance standard that can be achieved by all affected coal-fired EGUs nationwide regardless of the size, type of coal burned, or other relevant design factor of the unit.

Notably, the two FOAK CCS demonstration projects upon which EPA relies in setting the performance standard are relatively small units in size and therefore are not representative of the entire coal-fired EGU source category. For example, as discussed above, the Petra Nova Project involved *partial* application of CSS to only a 240 MW flue gas slipstream from existing Unit 8 at the Parish facility with a nameplate capacity of 654 MW. As a result, the Petra Nova Project had the capability to treat only about 37 percent of total CO_2 emissions from Unit 8 and thereby achieve only a

33 percent reduction in the total CO_2 emissions from Unit 8.[116] Similarly, the Boundary Dam CCS Project is not representative of the EGU source category. In particular, the CCS controls were applied to this relatively small coal-fired EGU with a nameplate generating capacity of 139 MW and a net output of 115 MW. This CCS project is therefore far smaller than the typical size of affected coal-fired EGUs that would need to install CCS.

And third, EPA cannot ignore these major data gaps on the performance of the CCS projects and set a stringent CO_2 90 percent removal level on a continuous annual basis predicated on the claim that the CAA provides the Agency with the authority to establish a technology-forcing performance standard. CAA section 111 does not allow EPA to set such a standard based on "mere speculation or conjecture"[117] regarding the current ability of CCS to achieve these CO_2 emission reductions CCS on large, baseload combustion turbines under a wide range of design and operating conditions.

15. The 2030 compliance deadline is unachievable.

EPA assumes that electric utilities will begin work on the development of CCS projects upon issuance of a final rule in June of 2024, prior to states development and submission to EPA of their implementation plans by June 2026 and EPA's approval of those state implementation plans by August 2027. Even assuming that electric utilities could expend major financial resources for CCS project development at an early date of June 2024 (which is clearly not the case), this would still leave only 5.5 years for the development of a CCS project and begin to comply with the CO_2 performance standard based on 90 percent removal by January 1, 2030. This compressed timeframe simply does not provide enough time for electric utilities to complete all of the steps necessary to develop a CCS project from concept through the deployment of onsite capture technology, as well as building out the pipeline transportation infrastructure and securing the permits necessary for the injection of the CO_2 emissions for sequestration or EOR purposes.[118]

EPA nonetheless claims that its compressed timeline of 5.5 years is "reasonable" because there are opportunities to shorten certain portions of the project schedule and perform concurrently various steps of the project development components. Not only has EPA failed to justify its claim for its proposed compressed time schedule for the many reasons already discussed above, but the Agency's time schedule of 5.5 years is also inconsistent with other time estimates for completing all of steps necessary for bringing online a CCS project from start to finish.

One notable example is that the Global CCS Institute (an organization whose mission is to promote CCS development) projects almost nine years to complete a CCS project and also has gone the record of saying that "a large complex CCS project may take a decade to progress from concept to operation."[119] Similarly, EPA's 5.5 year estimate is much shorter than the time schedules estimated for actual CCS projects (both planned and actually completed) that can take ten or more years to complete.[120]

Notably, this conclusion was reached in an examination of the time frames required for specific actual CCS projects that have already been completed or are now in the early stages of development.[121] These time schedules clearly confirm that 5.5 years is unrealistic and that ten or more years will typically be necessary for the development for projects.[122] This additional time is necessary to complete the major essential elements of the project, including—

- Design, engineering, planning, permitting, fabrication, and installation of the CCS technology for capturing the CO_2 emissions from the coal-fired EGU;
- Development, siting, permitting, and construction of the pipeline for transporting the CO_2 captured by the CCS equipment;
- Obtaining UIC Class VI permits and pore space for the injection and long-term storage of the captured CO_2 in an underground geologic formation; and
- Development and construction of multiple CO_2 injection wells and associated infrastructure.

Moreover, the completion of the CCS project and compliance with the applicable CO_2 performance standard under an extended timeframe may not even be feasible in the case of some projects due to permitting and other technical difficulties that are beyond the control of anyone seeking to use CCS technology. One notable example is the lengthy delays that can result from legal challenges to permits and other authorizations necessary for the construction and operation of the carbon capture, transport, and storage facilities that must be developed for the CCS project. Another cause for major delays can be the inability of federal and state permitting authorities to issue permits in a timely manner due to lack of agency resources and large number of pending project applications. This is most evident in the case of UIC Class VI permits for which there is already a backlog of permit applications—a problem that will likely only get worse by the increased need for the permitting of CCS projects under the Proposed Rule.
These longer time horizons for CCS project development further demonstrate the unreasonableness of EPA's compressed schedule and thereby demonstrate the arbitrariness and capriciousness of EPA's proposed performance standard based on CCS for long-term coal-fired EGUs.

16. Co-Firing with 40 Percent Natural Gas Is Not A Cost-Effective BSER Control Option.

EPA is proposing to set for medium-term coal-fired EGUs a CO_2 performance standard based on a BESR determination of 40 percent natural gas co-firing. That BSER determination applies to any coal-fired EGU that elects to permanently retire by no later than December 31, 2039. The application of the BSER results in the setting of a performance standard that will require the achievement of a 16 percent reduction in the unit's CO_2 emission rate on a lb CO_2/MWh-gross basis averaged over an annual calendar year and as measured from a unit-specific baseline.[123]

Natural gas co-firing is not a cost-effective control option for two fundamental reasons. The first is that EPA has significantly underestimated the projected price of natural gas. The second is that EPA has failed to fully consider all of the related natural gas supply infrastructure costs that electric utilities must incur in order to co-fire natural gas at 40 percent on an annual basis. When EPA fully accounts for these additional costs in its BSER determination, compliance costs for natural gas co-firing dramatically increase to levels that render this BSER control option not economically viable. For these reasons, EPA has no choice but to withdraw its proposed performance standard based on 40 percent natural gas co-firing.

Natural gas prices. A major cost component of this BSER control option is due to the increased consumption of natural gas at each affected EGU. In the Proposed Rule, EPA minimized the increased fuel costs of co-firing natural gas by projecting unrealistically low natural gas prices during the 2030-2039 compliance period. EPA's unrealistically low natural gas price projections stem from the fact that EPA assumes a 2030 natural gas price of $2.53/MMBtu (2019$), which is far lower than the EIA estimate. EIA projects a natural gas price approximately 20 percent higher at $3.00/MMBtu (2022$).

In addition, EPA seeks to minimize the cost impacts resulting from the increased natural gas consumption by limiting the projected price differential between coal and natural gas prices over the 2030-2039 compliance period.[124] This minimization of cost impacts is accomplished by forecasting that the expected price differential between coal and natural gas prices will decrease significantly to about $1.00/MMBtu by 2030 and then only increase at very modest levels thereafter over the following ten years through 2039.[125] By contrast, EIA estimates a much higher price differential for coal and natural gas over the same 2030-2039 period. In particular, the EIA price differential starts slightly higher than EPA's estimated value in 2030 ($1.05/MMBtu), but then increases dramatically thereafter from 2030 to 2039, as compared to the EPA projections.[126]

In calculating the estimated fleet average costs of natural gas co-firing for coal-fired units operating until 2040, EPA projects that the delivered cost of natural gas at $2.53/MMBtu "is assumed to increase to $2.91/MMBtu based on the implied increase in natural gas demand resulting from all units in the analysis co-firing at 40 percent natural gas on average, and an assumed elasticity of 1.1."[127] This price is a 15 percent increase in the delivered cost of natural gas used for co-firing by coal-fired EGUs.[128]

The table below compares the differential in the delivered cost of natural gas and coal under two scenarios. This first scenario is based on EIA's current forecast thru the year 2039 and the second is the same EIA forecast adjusted to reflect the same 15 percent increase in natural gas prices that EPA used to account for the increase in gas demand due to the Proposed Rule (as described above). Under this analysis, the cost differential between coal and natural gas prices is significantly higher, reaching $2.35 in 2039, than EPA's constant cost differential assumption of "about $1/MMBtu."

EIA Projected Cost Differential (2022$/MMBtu) Between Coal and Gas Prices

	Unadjusted Cost Differential[129]	Adjusted Cost Differential Reflecting 15% Increase
2030	$1.05	$1.50
2033	$1.37	$1.86
2035	$1.61	$2.14
2037	$1.70	$2.24
2039	$1.79	$2.35

This substantial underestimation of the price differential in the delivered price of natural gas and coal (about $1.35/MMBtu) significantly skews EPA's cost analysis for justifying the cost effectiveness of a coal-fired unit co-firing 40 percent natural gas. As the above table demonstrates, it results in EPA's annualized cost of $11 – $14/MWh and $64 – $78/ton for natural gas co-firing for an average unit being a significant underestimate.[130]

Infrastructure costs. In the Proposed Rule, EPA estimated modest costs for completing the various fixed infrastructure costs that would be incurred for co-firing natural gas at an average size coal-fired EGU. In particular, EPA's cost estimates for making the necessary boiler modifications were $52/kW and building the lateral natural gas pipeline were $92/kW.[131] While the boiler modification cost estimates are generally aligned with typical project costs, EPA has significantly underestimated the other natural gas supply infrastructure costs for delivering an adequate and reliable supply of natural gas necessary for natural gas co-firing at 40 percent. The development of this natural gas supply infrastructure is not just necessary for compliance, it also is critically important for securing a dependable supply of natural gas to ensure reliable operation of each affected coal-fired unit and the grid under the Proposed Rule.

The natural gas supply infrastructure costs of 40 percent natural gas co-firing are a function of four related factors. Those factors are:

- The number of affected EGUs that would need to secure substantial additional amounts of natural gas capacity;
- The location of the affected coal-fired units requiring substantial additional natural gas capacity and the unit's distance from existing pipeline transmission network;
- The amount of additional natural gas pipeline capacity (as characterized by the length, size, and number of lateral pipelines) that must be developed to provide an adequate and reliable supply of natural gas to each affected coal-fired unit; and
- The amount of additional natural gas capacity that would need to be supplied to each affected unit.

Although it may be difficult to make precise unit-specific determinations on each of the four factors noted above, EPA still has an obligation to assess the effects of these factors in determining the natural gas supply infrastructure costs of this possible

BSER control option. As the discussion below demonstrates, the Agency has failed to meet its burden of showing that these costs for building out the necessary pipeline supply capacity are reasonable and cost effective. Moreover, the discussion below illustrates that EPA's assessment of these four key factors greatly understates the pipeline supply infrastructure costs.

Number of affected coal-fired units. In the proposed rule, EPA asserts that "because a large supply of natural gas is available, devoting part of this supply for fuel for a coal-fired steam generating unit in place of the coal burned at the unit is an appropriate use of natural gas and will not adversely impact the energy system."[132] Putting aside its accuracy, EPA's statement entirely misses the point. Even if there is an adequate supply of natural gas, the key question here is the number of affected coal-fired EGUs that lack the natural gas pipeline infrastructure for delivering an adequate and reliable supply of natural gas for co-firing at 40 percent. The answer to this question is a clear no. This is evidenced by the fact that only about one-third of coal-fired EGUs combusted any amount of natural gas in 2017.[133] That number has not changed substantially since that time. Of these units, only four percent actually co-fired significant amounts of natural gas for the purpose of generating electricity.[134] For example, out of over 430 coal-fired EGUs in operation at the beginning of 2023, only ten have co-fired natural gas at levels exceeding 40 percent on average during 2021 and 2022.[135] By contrast, the vast majority of EGUs that have co-firing capability use the natural gas at very low levels for the purposes of starting up the boiler or holding it in "warm standby."

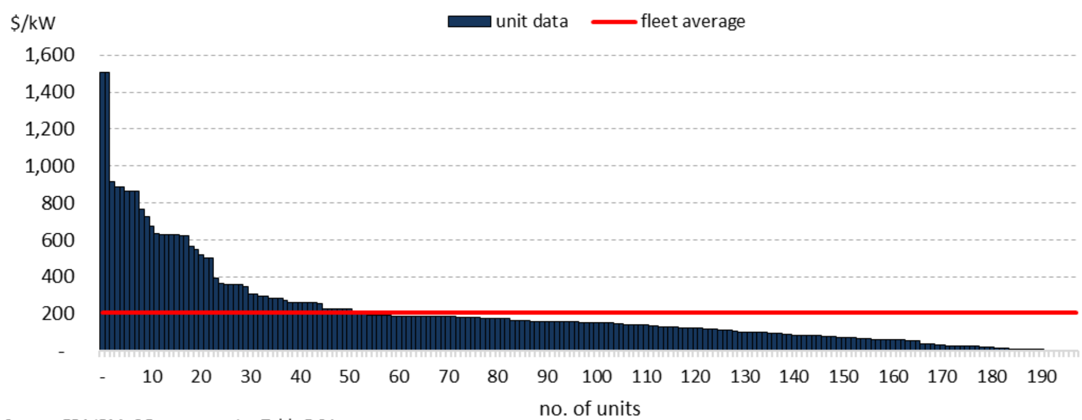
Location of coal-fired units. Most affected coal-fired EGUs are not located near an existing natural gas pipeline network and, as a result, would need to build out a lateral pipeline for delivering sufficient amounts of natural gas for co-firing. One clear indicator of this need to build out large amounts of lateral pipeline capacity is that almost 90 GW of the 107.6 GW of existing coal-fired generating capacity without retirement dates before 2032 are located more than five miles away from the closest major natural gas pipeline system, with some projects estimated to need more than 270 miles of additional pipeline infrastructure.[136] By contrast, just 11.2 GW coal-fired capacity are co-located with existing (or new) natural gas-fired EGUs and only 7.7 GW or 7 percent of capacity are located within five miles of existing natural gas supply infrastructure.[137]

Gas pipeline capacity. When estimating the pipeline size and associated costs with co-firing 40 percent natural gas at affected coal-fired EGUs, EPA assumed pipeline size equivalent to 60 percent of the net summer generating capacity at each coal-fired unit.[138] This assumption places a significant limitation on each unit's generating capacity when combusting natural gas. In such cases, EPA has effectively limited the maximum use of natural gas at each affected EGU to 60 percent when the unit is operating at 100 percent boiler load. Based on this artificial capacity limitation, EPA consequently calculated the average fleet-wide cost for the natural gas pipeline laterals to supply the retrofitted coal-fired EGUs with natural gas to be only $92/kW.

However, analysis of hourly generation data from existing coal-fired EGUs that co-fire natural gas for significant periods of time shows that these EGUs have co-fired 100 percent natural gas even at baseload operating levels (> 80 percent capacity factor) for significant periods of time during 2021 and 2022. Being able to co-fire 100 percent natural gas even at high boiler load levels is necessary for these boiler fuel retrofits to become economically viable. Limiting natural gas co-firing to 60 percent significantly constrains and thereby unnecessarily underestimates the size and associated costs to build the natural gas pipeline laterals needed to supply the retrofitted coal-fired EGUs with adequate natural gas supply.

A more representative cost for adding adequate natural gas supply to existing coal-fired EGUs to enable significant amounts of natural gas to be co-fired at the site is included in EPA's IPM modeling.[139] That EPA modeling shows, as illustrated in the chart below, that 96 GW currently do not have an adequate natural gas supply to convert existing coal-fired EGUs and enable 100 percent natural gas co-firing, which could be necessary to achieve 40 percent co-firing on an annual basis.

EPA-ESTIMATED NATURAL GAS LATERAL COST BY UNIT



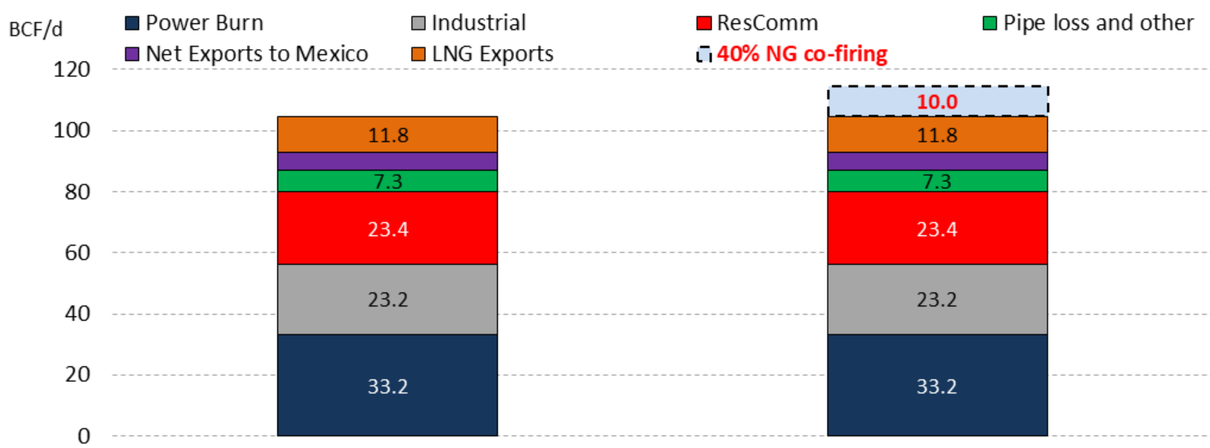
Source: EPA IPMv6 Documentation Table 5.21

According to EPA's own analysis, the fleet-wide average to add lateral capacity to enable these plants to co-fire 100 percent natural gas for significant periods of time at full load is $208/kW, more than double what EPA estimated in its technical support document accompanying the Proposed Rule. The magnitude of this cost impact is enormous. In effect, it is roughly equivalent to a coal-fired EGU adding selective catalytic reduction NOx emission control equipment, one of the most expensive coal plant retrofits, which costs roughly $200-250/kW.

The importance of developing adequate natural gas capacity cannot be overstated. The requirement to co-fire natural gas in significant quantities would require the fuel to be available at all times (called "firm" access), which is much more expensive and less available than non-firm access that is currently far more common at existing coal-fired EGUs. As the above discussion demonstrates, existing natural gas pipeline infrastructure to the plant will not be sufficient to supply the increased amount of natural gas. Further, natural gas is often unavailable at certain times of the year, which could result in reliability problems. (Less than two weeks ago, the North American Energy Standards Board issued a report[140] that highlights the natural gas sector's poor performance during recent winter storms because both the gas and electric systems do not function as an integrated whole, resulting in more than 240 lives lost and economic damage estimated to be as high as $130 billion during Storm Uri. During Storm Elliott, natural gas accounted for 72 percent of outages attributable to fuel problems.) Whether co-firing is viable ultimately requires site-by-site analysis. Because EPA's proposed BSER is not achievable "for the industry as a whole" and not just a subset of sources,[141] it is unlawful.

Converting the entire remaining coal fleet to enable 40 percent natural gas co-firing on an annual basis would add significant natural gas demand, as shown in the chart below.

2022 U.S. Natural Gas Demand and Potential Natural Gas Consumption Due to 40 Percent Co-Firing



Source: EVA Monthly NG Price Outlook

For purposes of illustration, if the 107 GW of remaining coal-fired generating capacity elected to co-fire 40 percent natural gas (as EPA has proposed with a national performance standard), the resulting annual natural gas demand could potentially surpass 10 billion cubic feet per day (BCF/D). Notably, this potential increase in natural gas demand is roughly equal to the entire LNG export capacity of the United States in 2022 and approximately half of all U.S. residential and commercial natural gas demand. An in-depth analysis into the maximum amount of natural gas able to be produced and transported based on the possible maximum amount of natural gas consumed under this BSER control scenario starting in 2030 is therefore needed to show that 40 percent natural gas co-firing is indeed widely available and technically feasible for the entire remaining coal fleet.

In summary, it should be emphasized that the estimated increase in fixed natural gas infrastructure supply costs represents yet another significant increase above EPA's own projections for co-firing 40 percent natural gas. To ensure a dependable supply of natural gas and the flexibility needed to meet rapid intra-day changes in demand, natural gas generators must obtain firm gas transportation on the transmission pipelines that serve them, which is a fixed cost that generators must pay to ensure reliable operations. Yet, EPA fails to include such fixed costs in its BSER analysis and instead assumes, incorrectly, that costs for firm mainline gas transportation can be excluded for the most part.[142] By excluding these substantial fixed infrastructure costs, EPA significantly underestimates the fuel cost of co-firing 40 percent natural gas – in clear violation of the law.

17. *A Natural Gas Co-Firing Standard Is Not Achievable by 2030.*

The technical support document for the Proposed Rule notes that compliance with the natural gas performance standard requires a coal-fired unit to complete each of the following actions:

- Modifications to the boiler, including completing the design, detailed engineering, site work/construction, and startup, testing of the unit;
- Completion of the commercial arrangements for the boiler modification;
- Construction of a lateral pipeline to the facility[143] to provide enough natural gas to enable 40 percent heat input to the boiler on an annual basis, including the planning, design, and permitting needed to construct the natural gas pipeline; and
- Purchase of sufficient quantities of the natural gas necessary to achieve the standard while also meeting electricity demands, particularly during peak demand periods.[144]

It is not feasible to complete all of these actions and achieve a performance standard based on 40 percent natural gas co-firing by 2030. This compliance deadline is not achievable for most coal-fired EGUs if they do not currently have natural gas pipeline access. Notably, this is the case for the majority of the affected coal-fired units as noted above. In the case of such generating facilities, EPA has significantly underestimated the time necessary to complete the design, permitting, and construction of a natural gas lateral pipeline as well as the time necessary for completing the boiler conversion work.

According to EPA's own estimates, the time needed for the conversion of a boiler is projected to be about three years. Work performed during the three-year period includes completing "conceptual studies, specifications/awards, detailed engineering, site work/mobilization, construction, and startup/testing."[145] Three years is far too short a time because the boiler conversion work needs to be coordinated with already-scheduled maintenance outages, which typically can occur on an annual cycle.

EPA also made unrealistic estimates of the time necessary for developing and bringing online a new natural gas pipeline. The average time required for pipeline construction is estimated by the Agency to be approximately 3.5 years but also could be much longer (as long as six years) in many cases.[146] The Agency's time estimate is broken down into three phases: planning and design, permitting and approval, and construction. According to EPA, it would take less than a year to complete the planning and design, 1.5 years (not to exceed four years) to secure the necessary construction permits (based on FERC data), and one year for building the pipeline. This time estimate is far too optimistic, especially to complete the permitting and construction of the pipeline. The construction of a lateral pipeline from the closest gas transmission pipeline will require a NEPA review and public consultation, each of which will likely add a significant amount of time to securing the necessary construction permits. Opposition from environmental groups and local landowners to the construction of lateral pipelines (which is typical in many, if not most cases) would likely add further delays in pipeline development.

Furthermore, the timeline does not account for the time for acquiring the necessary right-of-way access and permits. Notably, necessary state and local permits for pipeline construction cannot be obtained until the right-of-way is secured from landowners either through the negotiation of contractual agreements with each of those landowners or through eminent domain if provided under state law. In addition, the construction of the pipeline is contingent upon obtaining authorization to construct and operate the pipeline as well as demonstrating compliance with local zoning and siting requirements. In many states, for example, the authority for asserting eminent domain may not even exist and thereby greatly complicates the ability to secure the necessary right-of-way access for the construction and operation of the natural gas pipeline.

Finally, it should be noted that most electric utilities will not be in the position to incur major capital costs to construct a natural gas pipeline until after the Agency approves a state plan that establishes the 40-percent co-firing performance standard for a particular coal-fired EGU. Assuming that EPA issues a Final Rule by June of 2024 and retains the proposed regulatory timelines, states will not be issuing their final implementation plans until two years later in June 2026, with completeness determinations and then final approval occurring by August 2027 at the earliest. Under this expedited implementation schedule (which could very well be extended due to unavoidable regulatory delays), electric utilities will only have about 2.5 years to complete the design, permitting, and buildout of the natural gas line that is necessary for achieving compliance by January 1, 2030.

However, no electric utility can afford to invest the resources necessary for the boiler conversion or the construction of a lateral natural gas pipeline until EPA approves its state's plan that establishes the applicable performance standard for each affected EGU. Given that the pipeline design, permitting, and construction could take at least six years, a 2030 compliance deadline is wildly unrealistic and infeasible for any existing affected coal-fired EGU that does not already have access to a natural gas lateral pipeline of sufficient capacity to supply natural gas for meeting the 40 percent co-firing performance standard. Similar challenges would occur if the maintenance outage schedule for the affected coal-fired EGU does not align with the time needed for completing the boiler conversion.

In conclusion, EPA must withdraw its proposed performance standard based on 40 percent natural gas co-firing because, for the reasons explained above, it is not possible for most coal-fired EGUs to make the boiler conversions and other natural gas infrastructure changes by the 2030 compliance deadline.

18. Natural gas co-firing is barred because it "redefines" the source.

CAA section 111 does not authorize EPA to adopt performance standards that would have the effect of "redefining" the source based on well-established court precedent. This prohibition against the redefinition of the source clearly bars EPA from adopting the proposed performance standard for medium-term coal-fired EGUs, which requires such units to co-fire natural gas at an annual capacity factor of 40 percent. As a result, the EPA must withdraw the proposed performance standard and establish an entirely new standard that is not based on a requirement for coal-fired EGUs to switch from coal to a cleaner fuel source.

The court precedent barring the redefinition of the source is well-established. One court ruling is the Supreme Court decision in *West Virginia*. In that case, the Supreme Court addressed this issue in response to an argument raised in the dissenting opinion suggesting that EPA had authority to require coal-fired power plants to switch to cleaner fuels in order to achieve the environmental goals of the CAA. In response, the Court strongly disagreed with the dissenting opinion's overly broad interpretation of the statute, stating: "EPA has never ordered anything like that [*i.e., fuel switching*], and we doubt it could."[147]

The Supreme Court's clear rejection of this statutory interpretation is consistent with other longstanding legal precedent that prohibits EPA from adopting performance standards that "redefine the source." This legal precedent includes the Supreme Court decision in *Utility Air Regulatory Group v. EPA*, which ruled that technology-based performance standards under the CAA "cannot be used to order a fundamental redesign of the facility."[148] It is also consistent with the Seventh Circuit's decision in *Sierra Club v. EPA*.[149] In this case, the Seventh Circuit upheld longstanding Agency policy that the performance standards cannot require changes to fuel combusted (such as switching to low-sulfur subbituminous coals) because those types of fuel changes require "redesign of" or "fundamental change to" the facility.[150] In support of its ruling, the court explained that the choice of fuels is an essential part of a source's purpose and design, and that requiring a power plant to change its design to combust a different type of fuel (low-sulfur subbituminous coal instead of high-sulfur bituminous coal) constitutes "redefining the source, which is not permissible under the CAA.[151]

EPA's proposed performance standard requiring 40 percent natural gas co-firing violates this prohibition. In effect, it will require an existing coal-fired EGU to operate in a manner for which the unit was never designed to do, namely operate as hybrid coal/natural gas generating unit and combusting 40 percent of its fuel input as natural gas (instead of coal) on an annual basis. As noted above, compliance with this requirement would require fundamental changes to the design and operation of the existing coal-fired boiler and thereby combust natural gas at levels much higher than its original design levels. It also will require major changes in how it secures and delivers fuel (i.e., delivery of natural gas through pipelines instead transport of coal to the plant). Such a redefinition of the source is strictly prohibited by the courts as not permissible under the CAA.

19. Conclusion.

America's Power appreciates the opportunity to submit these comments. For reasons discussed above, the Proposed Rule suffers from many fundamental legal problems and technical deficiencies that EPA can only fix by withdrawing the Proposed Rule and reproposing an entirely new regulatory proposal that complies with the statutory requirements and is based on accurate information. Furthermore, EPA must evaluate the electric grid reliability impacts of the Proposed Rule. A comprehensive upfront evaluation of those reliability impacts is critically important to ensure that the Proposal (or reproposal) does not place grid reliability at even greater risk. We urge EPA to take these actions.

Sincerely,

Michelle A. Bloodworth

Michelle Bloodworth
President and CEO

Two Attachments:

"Overview & Analysis of Key Assumptions in EPA's 2023 Proposed GHG Rule," Energy Ventures Analysis, August 2023.

"Technical Comments on the Carbon Capture Utilization and Sequestration Aspects of the Proposed New Source Performance Standards for GHG Emissions from New and Reconstructed EGUs; Emission Guidelines for GHG Emissions from Existing EGUs; and Repeal of the Affordable Clean Energy Rule," J. Edward Cichanowicz and Michael C. Hein, August 7, 2023.

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[1] *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 From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule*, 88 Fed. Reg. 33,240 (May 23, 2023).

[2] America's Power has no choice but to supplement the points, issues, and concerns raised in its comments with additional information that is expected to become available as a result of the FERC Technical Conference. This need to supplement our comments further highlights the arbitrariness of the Agency's decision to grant a mere fifteen-day extension of the original sixty-day comment deadline, which was totally inadequate to analyze and prepare comments on a rule of unprecedented legal and technical complexity and impacts. Notably, the preamble to the Proposed Rule is 181 pages and is accompanied by another 73 pages of regulatory language, a 359-page Regulatory Impact Analysis, at least 216 pages of technical support, and other related documents. Finally, on Friday evening, July 7, 2023, EPA issued a 32-page "Memo to the Docket" titled "Integrated Proposal Modeling and Updated Baseline Analysis." This analysis was accompanied by 22 attachments added to the proposed rule's regulatory docket and four new IPM model run outputs, with each model run containing 18 separate Microsoft Excel spreadsheet outputs totaling 129 MB of data. All of these factors and considerations justify the need for America's Power to supplement its comments with additional information that is expected to become available during the FERC Technical Conference.

[3] Section 111(b)(2) of the CAA.

[4] Technical Comments on Carbon Capture Utilization and Sequestration (July 2023); Energy Ventures Analysis, *Overview & Analysis of Key Assumptions in EPA's 2023 Proposed GHG Rule*, at 27 (July 2023)
[5] According to the Energy Information Administration (EIA), the coal fleet totaled 317.6 GW in 2011 and is projected to total 188 GW in 2023.
[6] America's Power relies on a database that tracks announced coal retirements.
[7] See, for example, NERC's press announcement on May 17, 2023: *"Two-thirds of North America Faces Reliability Challenges in the Event of Widespread Heatwaves . . .* NERC's *2023 Summer Reliability Assessment* warns that two-thirds of North America is at risk of energy shortfalls this summer during periods of extreme demand." NERC's press announcement is available here.
[8] Senate Committee on Energy & Natural Resources, Full Committee Hearing to Conduct Oversight of FERC (May 4, 2023), available here.
[9] Written Testimony of James P. Danly, Commissioner, FERC, Before the Committee on Energy & Natural Resources, U.S. Senate, at 1 (May 4, 2023), available here.
[10] Opening Statement of Mark C. Christie, Commissioner, FERC, Senate Energy & Natural Resources Committee Hearing, at 1, 2 (May 4, 2023), available here.
[11] Senate Committee on Energy & Natural Resources, Full Committee Hearing to Conduct Oversight of FERC, at 2:08-12 – 2:08-29 (May 4, 2023), available here; *see also* Testimony of Willie Phillips, Chairman, FERC, Senate Energy & Natural Resources Committee Hearing, at (May 4, 2023), available here.
[12] Senate Committee on Energy & Natural Resources, Full Committee Hearing to Examine the Reliability and Resiliency of Electric Services in the U.S. in Light of Recent Reliability Assessments and Alerts (June 1, 2023), here.
[13] Testimony of James B. Robb, President and CEO, NERC, Before the Committee on Energy & Natural Resources, U.S. Senate (June 1, 2023), available here.
[14] These regulations are the Coal Combustion Residuals Rule, Good Neighbor Rule, Effluent Limitations Guidelines (proposed), Mercury and Air Toxics Standards (proposed), a Carbon Rule (proposed), and the Regional Haze Rule. For example, EPA projects the Good Neighbor Rule will cause the retirement of 13 GW of coal by 2030.
[15] *See* EPA, Power Sector Modeling, available here (last visited July 20, 2023).
[16] EPA, Office of Air and Radiation, "Resource Adequacy Analysis Technical Support Document," at 3 (Apr. 2023) (emphasis added) (Resource Adequacy Analysis TSD), available here.
[17] Of the 72 GW of coal projected for 2030, 9 GW would have CCS and 63 GW would not. In 2035, 12 GW would have CCS and 39 GW would not. EPA, Office of Air and Radiation, "Integrated Proposal Modeling and Updated Baseline Analysis – Memo to the Docket" (July 7, 2023), available here.
[18] Resource Adequacy Analysis TSD at 3-4
[19] Proposed Rule at 33,246.
[20] Resource Adequacy Analysis TSD at 3.
[21] *Id.* at 2.
[22] *Id.* EPA defines **resource adequacy** as "the provision of adequate generating resources to meet projected load and generating reserve requirements in each power region." The agency says that **reliability** "includes the ability to deliver the resources to the loads, such that the overall power grid remains stable." EPA goes on to say that "resource adequacy . . . is necessary (but not sufficient) for grid reliability." *Id (emphasis added).*
[23] *Id.* at 3.
[24] *Id.*
[25] EPA, Office of Air Quality Planning and Standards, "Documentation for Post-IRA 2022 Reference Case," at 4-1 (Generating Resources) (Apr. 5, 2023), available here.
[26] *Id.* at 3-11 (Power System Operation Assumptions).
[27] EPA, "Regulatory Impact Analysis for the Proposed National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology," at tbl.3-14 (Apr. 2023), available here.
[28] REPEAT Project, "Electric Transmission is Key to Unlock the Full Potential of the Inflation Reduction Act" (Sept. 2022), available here. In particular, the study concludes: "Over 80% of the potential emissions reductions delivered by IRA in 2030 are lost if transmission expansion is constrained to 1%/year, and roughly 25% are lost if growth is limited to 1.5%/year" and " To unlock the full emissions reduction potential of the *Inflation Reduction Act*, the pace of transmission expansion must more than double the rate over the last decade to reach an average of ~2.3%/year. That rate of expansion is comparable to the long-term average rate of transmission additions from 1978-2020." *Id.* at 4.
[29] Proposed Rule, 88 Fed. Reg. at 33,415.

[30] *See Id.* at 33,415-16. To this end, EPA and DOE have entered into a Joint Memorandum, which provides a general description on how the two federal agencies may work together in the future but does not take any specific steps to proactively assess and address those potential electric reliability risks before they begin to occur. *See* EPA, "Electric Reliability: Memorandum of Understanding on Interagency Communication and Consultation on Electric Reliability," (Mar. 9, 2023), available here. EPA also discounts the significance of future electric reliability problems by indicating that the Agency has discretion to issue "administrative compliance orders" (ACO) that would defer enforcement actions for noncompliance with applicable CAA requirements. Unfortunately, the process for securing regulatory relief through an ACO is a lengthy and complicated process subject to numerous restrictions that is not workable for providing immediate short-term relief from the onerous compliance obligations imposed by the Proposed Rule. Furthermore, the ACO mechanism, as proposed by EPA, does not provide much comfort for those without electricity for their basic needs and welfare.
[31] *West Virginia v. EPA*, 142 S. Ct. 2587 (2022).
32 *Id.* at 2593.
[33] Proposed Rule, 88 Fed. Reg. at 33,257.
[34] *Id.* at 33,258.
[35] 142 S. Ct. at 2587.
[36] *Id.* at 2610.
[37] *Id.*
[38] *See Id.*
[39] *Id.* at 2616 (emphasis added).
[40] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 80 Fed. Reg. 64,662, at 64,667, 64,727-29, 64,748 (Oct. 23, 2015) (CPP).
[41] *Id.* at 64,731-32.
[42] *West Virginia*, 142 S. Ct. at 2614.
[43] Proposed Rule, 88 Fed. Reg. at 33,272.
[44] Section 111(b)(2) of the CAA.
[45] In the Proposed Rule, EPA provides a legal basis for subcategorization by retirement date that is untethered from the statute. That basis is tied to the consideration of factors, such as "cost reasonableness" and the "operating time horizon" of the unit. These factors, however, are not referenced (either directly or indirectly) in CAA section 111(b)(2) as permissible factors that the Agency may consider in the subcategorization of the EGU source category. Rather, the statute provides EPA with the authority to subcategorize by physical or operational characteristics, such as "classes, types, and sizes within categories."
[46] The same "out-side-the-fence" problems arise in the case of the buildout of a national network for the production and transport of clean hydrogen.
[47] *California v. EPA*, ___ F.4th ___, No. 21-1018, 2023 WL 4280835, at *4 (D.C. Cir. June 30, 2023).
[48] *Id.* at *1.
[49] Although not a focus of these comments, the same problem also applies to EPA's proposed BSER determination regarding a national system for the production and deployment of clean hydrogen. The buildout of such a national system for the production and transportation of clean hydrogen is neither adequately demonstrated nor feasible at this time—particularly given that many of the challenges of building out such a national clean hydrogen system are beyond the control of affected electric utilities.
[50] Proposed Rule, 88 Fed. Reg. at 333,289
[51] 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, § 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 here.
[52] 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 here. 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, integrated gasification combined cycle (IGCC) technology, and the use of clean fuels as BSER due in part to the unavailability of these emission reduction options by all affected sources within the EGU source category. *See* Standards of Performance for Electric Utility Steam Generating Units for

Which Construction Is Commenced After September 18, 1978, 70 Fed. Reg. 9706, 9712-15 (Feb. 28, 2005).
[53] Section 111(d)(1) of the CAA.
[54] *Luminant Generation Co. v. EPA*, 675 F.3d 917, 921 (5th Cir. 2012).
[55] Section 111(a)(2) of the CAA.
[56] *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 433 (D.C. Cir. 1973) (emphasis added); *see also NRDC v. Thomas*, 805 F.2d 410, 428 n.30 (D.C. Cir. 1986).
[57] *Lignite Energy Council v. EPA*, 198 F.3d 930, 934 (D.C. Cir. 1999) (citing *Nat'l Asphalt Pavement Ass'n v. Train*, 539 F.2d 775, 787 (D.C. Cir. 1976)).
[58] *Nat'l Lime Ass'n v. EPA*, 627 F.2d 416, 433 (D.C. Cir. 1980).
[59] *Id.* at 431 n.46.
[60] In the preamble to the Proposed Rule, EPA cites to court decisions that recognize EPA's authority to make reasonable projections on the use of control technologies not "in actual routine use." However, this authority is limited to rulemakings in which the Agency is setting performance standards for **new** stationary sources under section 111(b) of the CAA. Neither the statute nor court rulings cited by EPA support the claim that the Agency also has the authority to adopt a technology-forcing performance standard for **existing** coal-fired EGUs under CAA section 111(d). These court rulings are inapplicable and therefore do not allow EPA to set a CO_2 performance based on an emerging control technology for which there is no coal-fired EGU operating with CCS at commercial scale and deep underground sequestration. Moreover, this interpretation was confirmed in a recent court determination in which the D.C. Circuit ruled that the CAA must "explicitly require[ ] the EPA to . . . adopt a technology-forcing approach." *California v. EPA*, 2023 WL 4280835 at *4. Nothing in the statute authorizes EPA to do so in setting performance standards for existing EGUs under CAA section 111(d). *Id.* at *1.
[61] The many technical deficiencies regarding why CCS is not "adequately demonstrated" are presented in detail in Section 3 of the Technical Comments on Carbon Capture Utilization and Sequestration Prepared for and Submitted by America's Power to EPA Docket (CCS Technical Report) (attached hereto). This discussion in the attached report is intended to support and expand upon the major technical deficiencies discussed in these comments.
[62] *See* Duckett, A., "The Privilege of Being First," The Chemical Engineer (May 1, 2018) (Duckett Article), available here.
[63] *See Id.*
[64] 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 Id*. 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.*
[65] 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 Id*.
[66] *See* EIA, *Petra Nova is one of two carbon capture and sequestration power plants in the world* (Oct. 31, 2017) (Petra Nova EIA Overview), available here.
[67] See Energy Ventures Analysis, *Overview & Analysis of Key Assumptions in EPA's 2023 Proposed GHG Rule*, at 27 (July 2023) (EVA Analysis) (attached hereto). Initially hailed as the country's pioneering electricity plant utilizing gasification technology to convert coal into syngas while capturing 65 percent of the carbon emissions, totaling 3.3 million tons per year, the project faced numerous challenges from its inception. *Id.*
[68] Proposed Rule, 88 Fed. Reg. at 33,392. Other small-scale pilot projects cited by the Carbon Proposal include (1) the Searles Valley Minerals soda ash plant in California, which captured and used approximately 270,000 metric tons of CO_2 annually; and (2) the Quest CO_2 capture facility in Canada captured from three steam generators approximately one million tons or 80 percent of the CO_2 annually. *Id*.
[69] *Id.*

[70] The many technical deficiencies in EPA's cost analysis that document excessively high costs of CCS are presented in detail in Section 4 of the attached CCS Technical Report. This discussion in the attached report is intended to support and expand upon the major technical deficiencies discussed in these comments.
[71] *Lignite Energy Council*, 198 F.3d at 933.
[72] *Portland Cement Ass'n v. EPA*, 513 F.2d 506, 508 (D.C. Cir. 1975).
[73] *Sierra Club v. Costle*, 657 F.2d 298, 343 (D.C. Cir. 1981).
[74] *Id.*
[75] Review of Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units, 83 Fed. Reg. 65,424, 65,433 (Dec. 20, 2018); Standards of Performance for Greenhouse Gas Emissions From New Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 1430, 1464 (Jan. 8, 2014).
[76] 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 retrofit capital cost estimates of $2,222 per kilowatt for a 400MW unit.
[77] *See* Duckett Article.
[78] Coal Industry Advisory Board, "An International Commitment to CCS: Policies and Incentives to Enable a Low-Carbon Energy Future," at 19 (Nov. 21, 2016) (CIAB Paper).
[79] *Id.*
[80] https://www.eia.gov/todayinenergy/detail.php?id=33552
[81] Those six CCS projects were prepared for Sask Power's Shand Power Station, Basin Electric's Dry Fork Plant, Project Tundra at Minnkota's Milton R. Young, Enchant Energy's San Juan Generating Station, Nebraska Public Power District's Gerald Gentleman Station, and Prairie State's Generating Station. *See* CCS Technical Report.
[82] CCS Technical Report at 13-15.
[83] CCS Technical Report at 15-16.
[84] *See* CCS Technical Report at 17-19.
[85] IPM Model – Updates to Cost and Performance for APC Technologies - CO_2 Reduction Retrofit Cost Development Methodology, Docket ID No. EPA-HQ-OAR-2023-0072 (Sargent & Lundy Study).
[86] This is significant, for two reasons. First, the levelized cost for CO_2 removal at Petra Nova has never been verified either independently or by the project owners. And second, the cost estimates shown for proposed projects to be built are speculative at best.
[87] Global Status of CCS 2019: Targeting Climate Change. Figure 8. https://ccsknowledge.com/pub/Publications/Global_Status%20of_CCS_2019%20_GCCSI.pdf
[88] https://www.globalccsinstitute.com
[89] Finally, the costs incurred for Petra Nova (which is a dubious number that has never been independently verified and unrepresentative of typical future CCS projects) is the only historical data point that would suggest CCS costs are declining. In fact, removing the Petra Nova cost estimate from the curve would show an **upward** trend in CCS costs for completed projects overtime. This raises significant questions as to the veracity of S&L report's projected costs and thus EPA's estimates for CCS costs going forward.
[90] Cost And Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity, Rev. 4A (October 2022) (NETL Report), available here.
[91] NETL report (emphasis added).
[92] IPM Model – Updates to Cost and Performance for APC Technologies - CO_2 Reduction Retrofit Cost Development Methodology, Docket ID No. EPA-HQ-OAR-2023-0072
[93] https://www.epa.gov/system/files/documents/2023-02/Chapter%2010%20-%20Financial%20Assumptions.pdf
[94] EPA-HQ-OAR-2023-0072-0061_attachment_3, Docket ID No. EPA-HQ-OAR-2023-0072
[95] Integrated Proposal Modeling and Updated Baseline Analysis, Memo to the Docket, Docket ID No. EPA-HQ-OAR-2023-0072
[96] https://www.tandfonline.com/doi/pdf/10.1080/00022470.1977.10470518
[97] 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 Internal Revenue Service Code. *See* Section 1307 of EPAct05, codified at 26 U.S.C. § 48A(g).

[98] 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 NSPS 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 238-39 (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. H.R. 1640 includes a similar explanation of the prohibition contained in the Clean Air Coal Program (which became EPAct05 § 421). *Id.* at 240.

[99] 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.

[100] *See* Section 402 of EPAct05 (barring EPA from considering results from federal demonstration projects funded by DOE's CCPI). Notably, federal demonstration projects receiving federal tax credits under Section 48A of the IRC are also subject to a similar prohibition under Section 402 of EPAct05.

[101] 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.*, 1997 Subpart Da TSD at 3-43, 3-49, 3-55.

[102] McCutchen Letter at 1. 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 emission reduction options by all affected sources within the EGU source category. 70 Fed. Reg. at 9712-15.

[103] The many difficult pipeline permitting, and development hurdles are presented in detail in Section 5 of the attached CCS Technical Report). This discussion of these hurdles in the Report is intended to support and expand upon the major technical deficiencies discussed in these comments.

[104] *See* 83 Fed. Reg. at 65,441-42.

[105] *See Id*; *see also* Steven T. Anderson, *Risk, Liability, and Economic Issues with Long-Term CO_2 Storage—A Review*, 26 Nat. Res. Research 89-112 (Jan. 2017), available here.

[106] *See* Steven T. Anderson, *Cost Implications of Uncertainty in CO_2 Storage Resource Estimates: A Review*, 26 Nat. Res. Research 137-59 (Apr. 2017), available here.

[107] DOE, Office of Fossil Energy and Carbon Management, NETL, The United States 2012 Carbon Utilization and Storage Atlas, 4th Ed. (Dec. 19, 2012) (DOE Atlas), available here.

[108] *See Id.*

[109] 83 Fed. Reg. at 65,443.

[110] *See* CCSReg Project, *State CCS Policy*, available here (last visited July 21, 2023).

[111] *See* Proposed Rule, 88 Fed. Reg. at 33,355, 33,359. According to the Proposed Rule, a 90 percent capture would result in an 88.4 percent reduction in the emission rate for the affected coal-fired unit on a lb CO_2/MWh-gross basis. *Id*.

[112] Section 111(a)(1) of the CAA.

[113] *Nat'l Lime Ass'n*, 627 F.2d at 433.

[114] *Id.* at 431 n.46.

[115] *Id.* at 431.

[116] *See* Petra Nova EIA Overview.

[117] *Lignite Energy Council*, 198 F.3d at 934.

[118] The many technical deficiencies regarding EPA's proposed 2030 compliance schedule are presented in detail in Section 6 of CCS Technical Report. This discussion in the report is intended to support and expand upon the major technical deficiencies discussed in these comments.

[119] Global CCS Institute, *Global Status of CCS 2022* at 47-48, available here.

[120] *See* Technical Comments on Carbon Capture Utilization and Sequestration Prepared for and Submitted by America's Power to EPA Docket, at 15-16 (CCS Technical Report).

[121] CCS Technical Report at 30-35.
[122] CCS Technical Report at ii, 30-35.
[123] 88 Fed. Reg. at 33,245.
[124] 88 Fed. Reg. at 33,353; *Greenhouse Gas Mitigation Measures for Steam Generating Units TSD*, at 10, 35-37.
[125] 88 Fed. Reg. at 33,353; *Greenhouse Gas Mitigation Measures for Steam Generating Units TSD*, at 10, 35-37.
[126] EIA, *Annual Energy Outlook 2023*, at tbl.3 (Mar. 16, 2023) (reference case; electric power sector) (EIA AEO 2023), available here.
[127] *GHG Mitigation Measures for Steam Generating Units* TSD at 16.
[128] EPA provides no information about the expected change in the cost of natural gas from 2030 to 2040 in either the preamble to Proposed Rule or EPA's Technical Support Document ("TSD"), entitled *GHG Mitigation Measures for Steam Generating Units*, which is used for determining the costs of achieving the 40 percent co-firing control level.
[129] EIA AEO 2023 at tbl.3 (reference case; electric power sector).
[130] As a general matter, these differences in coal and natural gas price projections are tied to major differences in coal and natural gas generation projected by EIA and EPA. EIA projects total demand (domestic consumption and net exports) growing by 15.1 percent (5.5 trillion cubic feet per year) between 2028 and 2050, while EPA's model projects a decline in natural gas demand of 12.2 percent (4.9 trillion cubic feet). *See* AEO 2023 Reference Case; EPA RIA Reference Case. As a result of this significant discrepancy in demand (totaling 27.3 percent and 10.4 trillion cubic feet), EPA's reference baseline (inclusive of IRA impacts) projects a reduction in EGU sector emissions by 80 percent below 2005 levels. *See* EPA RIA Reference Case. By contrast, if EPA's powerplant rule is finalized as proposed and remains effective through 2040, EPA projects that CO_2 emissions will decrease by 81 percent below 2005 levels. In effect, the entire regulatory scheme in the Proposed Rule is forecasted by the Agency modeling analysis to achieve additional emissions reductions in 2040 of only one percent beyond EPA's projected reference baseline. *See* AEO 2023 Reference Case. This conclusion does not just highlight major problems with EPA's cost analyses for natural gas co-firing but also raises the fundamental question about the effectiveness of the EPA rule – namely what purpose an EPA rule serves if that rule that achieves only one percent incremental reduction in CO_2 emissions from the power sector over the next 15 to 20 years.
[131] 88 Fed. Reg. at 33,353. *See also* EPA, *Greenhouse Gas Mitigation Measures for Steam Generating Units, Technical Support Document*, (May 23, 2023) (*GHG Mitigation Measures for Steam Generating Units* TSD).
[132] *Id.*
[133] 84 Fed. Reg. at 32,544.
[134] *Id.*
[135] EVA Analysis at 12.
[136] EVA Analysis at 13.
[137] EVA Analysis at 10. *See also* EPA TSD, entitled Documentation for Lateral Cost Estimation, available here. These numbers on the units located near natural gas pipeline systems are consistent with the trends observed with the past natural conversions, whereby only 2.2 GW (or 11 percent) of 20 GW that have previously converted to natural gas since 2012 had a need to build natural gas pipeline laterals greater than five miles in length. EVA Analysis at 10.
[138] EPA GHG Mitigation Measure for Steam EGUs TSD.
[139] *See* Table 5.21 of Integrated Power Modeling (IPM) v6 documentation.
[140] North American Energy Standards Board, *Gas Electric Harmonization Forum Report* (July 28, 2023).
[141] *National Lime Ass'n*, 627 F.2d at 431.
[142] Documentation for Lateral Cost Estimation, p. 3.
[143] Notably, mainline pipeline expansions are complex, and an upstream expansion to deliver firm capacity can be lengthier than constructing the lateral itself.
[144] EPA, *Greenhouse Gas Mitigation Measures for Steam Generating Units TSD*, at 10, 35-37.
[145] *GHG Mitigation Measures for Steam Generating Units* TSD at 10.
[146] *Id.* at 13.
[147] 142 S. Ct. at 2612 n.3.
[148] *Utility Air Regulatory Group v. EPA*, 134 S. Ct. 2427, 2448 (2014)
[149] *Sierra Club v. EPA*, 499 F.3d 653 (7th Cir. 2007).

[150] 499 F.3d at 655-56. *See also In re Prairie State Generating Co.*, 13 E.A.D. at 25 (holding that it is "long-standing EPA policy that certain fuel choices are integral to the electric power generating station's basic design").
[151] 499 F.3d at 655-56.

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Overview & Analysis of Key Assumptions in EPA's 2023 Proposed GHG Rule

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Introduction

On May 23, 2023, the Environmental Protection Agency (EPA) proposed updated New Source Performance Standards (NSPS) for greenhouse gas emissions (GHG) from new, modified, and reconstructed fossil fuel-fired electric generating units (EGUs) as well as emission guidelines for greenhouse gas emissions from existing fossil fuel-fired EGUs and the repeal of the Trump-era Affordable Clean Energy Rule. The proposed GHG Rule aims to regulate CO_2 emissions from the majority of fossil fuel power plants in the United States starting in 2030 when the first compliance deadline comes into effect.

This report focuses exclusively on the EPA's methodology of establishing the emission guidelines for existing coal-fired steam EGUs and highlights major problems in EPA's support for the proposed emission guidelines, including:

- Causes of Coal Power Plant Retirements: In its Technical Support Document on Power Sector Trends, EPA contends that the large number of coal plants that have retired and are planned to retire through 2030 are primarily due to the age of these plants, asserting that coal plants can be expected to retire when they are about 50 years old due to rising costs. This analysis is severely flawed. The primary cause of coal plant retirements is the imposition of new EPA regulations and enforcement activities, not age. Because many coal plants were built in the period 1965-1980 without the newest pollution control technologies and EPA imposed many new regulations in the period 2012-2016, these plants retired after about 50 years because they were faced with new environmental compliance deadlines. Coal plants can continue to run economically for an indefinite period with proper maintenance (there are several coal plants operating efficiently that are 70 years old today and these plants have no plans to retire before 2030) and many would not retire if EPA does not promulgate the proposed GHG rule. . EPA assumes that every coal plant that has announced plans to retire before 2032 will retire absent the GHG Rule, yet many plants have since delayed or canceled plans to retire for reliability reasons. The proposed GHG Rule will take away the flexibility to delay or reverse announced retirement plans and this option to support system reliability will be gone.
- Natural Gas Co-Firing as BSER: Natural gas co-firing is not a technology that is widely available and cost-appropriate for most coal plants. The coal plants that have converted to gas firing or co-firing have almost all been located very close to large pipelines and did not incur large costs to connect to gas supply. Most of the remaining coal plants are located far from major pipelines and would have much higher costs to connect to pipeline supply. Additional gas demand will place enormous strain on a supply base that, while abundant, is finite and already constrained as evidenced by past extreme weather events.[1] Further, EPA's proposed compliance schedule does not provide adequate time to permit and construct new pipelines to begin gas co-firing by the compliance date in 2030.
- EPA's Power Sector Modeling: EPA's IPM model is not designed to analyze the reliability of the electric power system. It always assumes that enough power plants will be constructed to meet demand. The IPM model assumes unrealistic capacity factors for renewable power plants without consideration of the need to curtail excess renewable generation. The results of EPA's IPM model under the Reference Case are very different from the published forecast by the Energy Information Administration.
- Carbon Capture and Sequestration (CCS) as BSER: EPA asserts that CCS technology is available for use as BSER for coal plants to comply with the proposed GHG rule. However, there are no commercial CCS projects in existence today. EPA relies on two small demonstration projects (one of which is idled) and a proposed new gas-fired power plant with CCS that is merely a press release with no committed investment. Few of the existing coal plants are located near geological formations that can support sequestration of carbon dioxide, and pipeline capacity does not exist to transport CO_2 from the coal plants to potential sequestration locations.

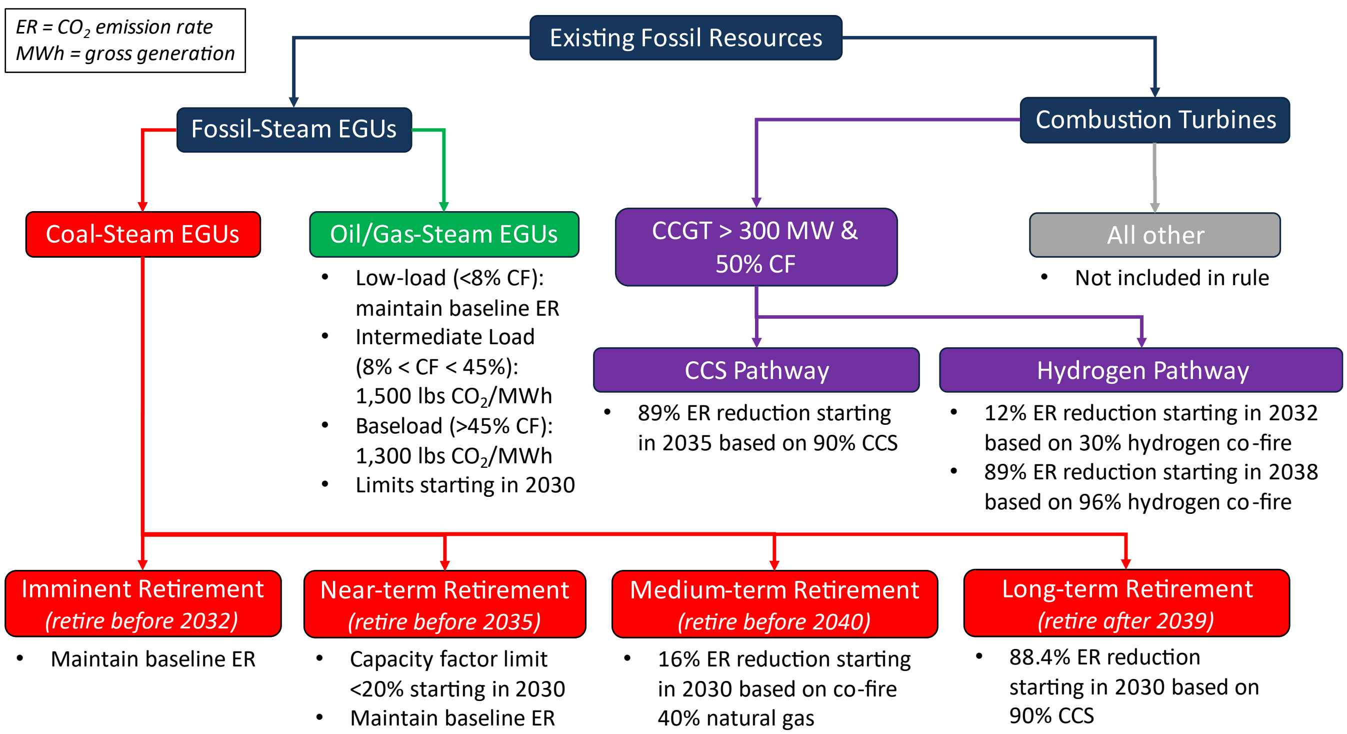
[1] Winter Storms Elliott and Uri are reported to have caused financial losses of $80 - $130 billion in Texas alone https://comptroller.texas.gov/economy/fiscal-notes/2021/oct/winter-storm-impact.php#:~:text=The%20storm%20contributed%20to%20at,%2480%20billion%20to%20%24130%20billion

Overview of EPA's Emission Guidelines for Coal-Fired Steam EGUs

EPA's proposed emission guidelines for fossil fuel steam EGUs apply to all EGUs in operation or under construction before January 8, 2014, with a capacity greater than 25 megawatts (MW) and a baseload fuel input rating greater than 250 MMBtu/h. Furthermore, the EPA proposes to subcategorize the existing fossil fuel steam EGU fleet based on the fossil fuel they consume. For example, the EPA considers an EGU a coal-fired steam generating unit that burns coal for more than 10% of the average annual heat input during the three calendar years prior to the proposed compliance deadline (i.e., January 1, 2030) or for more than 15% of annual heat input during any of those calendar years, or that retains the capability to burn coal after December 31, 2029. The same subcategorization principles apply to oil and natural gas-fired steam EGUs.

EPA proposes to apply GHG emission guidelines to oil and natural gas-fired steam EGUs based on historical load levels of the individual EGU. On the other hand, the EPA proposes to subcategorize coal-fired steam EGUs based on announced or planned EGU retirements. **EXHIBIT *1*** provides an overview of the GHG emission guidelines applicable to existing fossil fuel-fired EGUs as proposed by EPA.

EXHIBIT 1: OVERVIEW OF EPA'S PROPOSED GHG EMISSION GUIDELINES FOR EXISTING FOSSIL FUEL-FIRED EGUS



As shown in **EXHIBIT *1***, the EPA proposes to establish four subcategories for coal-fired steam EGUs based on their operating horizons. "Imminent-term" coal EGUs are those that have elected to commit to retiring before January 1, 2032, permanently. "Near-term" coal EGUs are those that have elected to commit to permanently retire before January 1, 2035, and operate at an annual capacity factor of 20% or less for the four years between 2030 and 2034. "Medium-term" coal EGUs are those that have elected to commit to permanently retiring before January 1, 2040, but do not meet the definition of "near-term" coal EGUs. "Long-term" coal EGUs are those units that do not have planned retirements before 2040. Upon EPA's approval of the State Implementation Plans (SIPs), the retirement dates used to subcategorize the affected coal-fired steam EGUs will become federally enforceable and can only be adjusted after EPA's approval of a subsequent SIP revision that includes an updated retirement date.

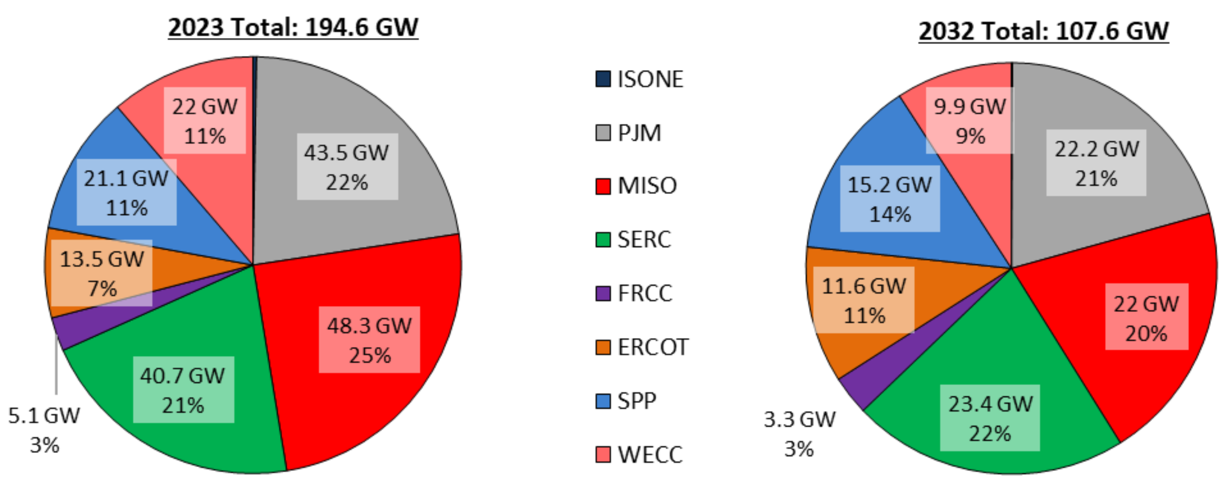
For each of these four subcategories, the EPA evaluated the Best System of Emissions Reduction (BSER) as defined by the Clean Air Act. For the imminent-term subcategory, the EPA proposes no additional CO_2 emission reduction beyond the established baseline CO_2 emission rate for the affected EGU due to the shortened remaining life of the EGU (i.e., two years). For the near-term subcategory, the EPA also proposes no change to the baseline CO_2 emission rate of the affected EGU over the five years of the remaining operating horizon as long as the coal-fired EGU in this subcategory maintains an annual capacity factor of 20% or less. For the medium and long-term subcategories, the EPA evaluated both natural gas co-firing and carbon capture and sequestration (CCS) as appropriate BSER. For the medium-term subcategory, the EPA ultimately settled on requiring a 16% CO_2 emission rate reduction from the baseline emission rate starting on January 1, 2030, based on the BSER of co-firing 40% natural gas annually on a fuel heat input basis. For the long-term subcategory, the EPA deemed 90% CCS as the appropriate BSER for coal-fired steam EGUs. As a result, baseline CO_2 emission rates for coal-fired steam EGUs in this subcategory are required to be reduced by 88.4% starting on January 1, 2030.

The remaining sections of the report provide an overview of the current U.S. coal fleet, the primary reasons for coal unit retirements over the last decade, critical analyses of natural gas co-firing and CCS as appropriate BSER, as well as an overview of the shortcomings of EPA's power sector modeling as part of its GHG rule proposal.

History and Current State of the U.S. Coal Fleet

On January 1, 2023, there were 425 coal-fired steam EGUs totaling approximately 194.6 gigawatts (GW) of generating capacity operational in the United States. **EXHIBIT *2*** shows the operating coal-fired operating capacity by the U.S. power market/region in 2023 and the remaining capacity expected to be operating in 2032 (229 units totaling 107.6 GW) based on current announced plans.

EXHIBIT 2: 2023 (LEFT) & 2032 (RIGHT) U.S. COAL CAPACITY BY POWER MARKET



Source: EIA Form-860 data

Source: EVA Power Plant Tracking System

Over two-thirds of the remaining operating coal capacity is located in just three regions: PJM, MISO, and SERC. Based on EVA's review of current company announcements and long-term resource plans, almost 85 GW or 45% of the current operating coal capacity is scheduled for retirement before 2032[2] and are, therefore, either unaffected by the proposed GHG rule or fall into the imminent-term subcategory, which limits the plants to no increase in emissions but does not

[2] Filings on the Energy Information Administration Form 860 show planned retirement of 110 units that total 46.7 GW of summer capacity https://www.eia.gov/electricity/data/eia860/ 2022 early release. The larger number of 85 GW comes from EVA's review of announcements and integrated resource plans.

require adoption of a BSER strategy.[3] The remaining 107.6 GW will likely be subject to the proposed GHG rule requirements and fall into one of the remaining three subcategories (or advance their retirement to before 2032).

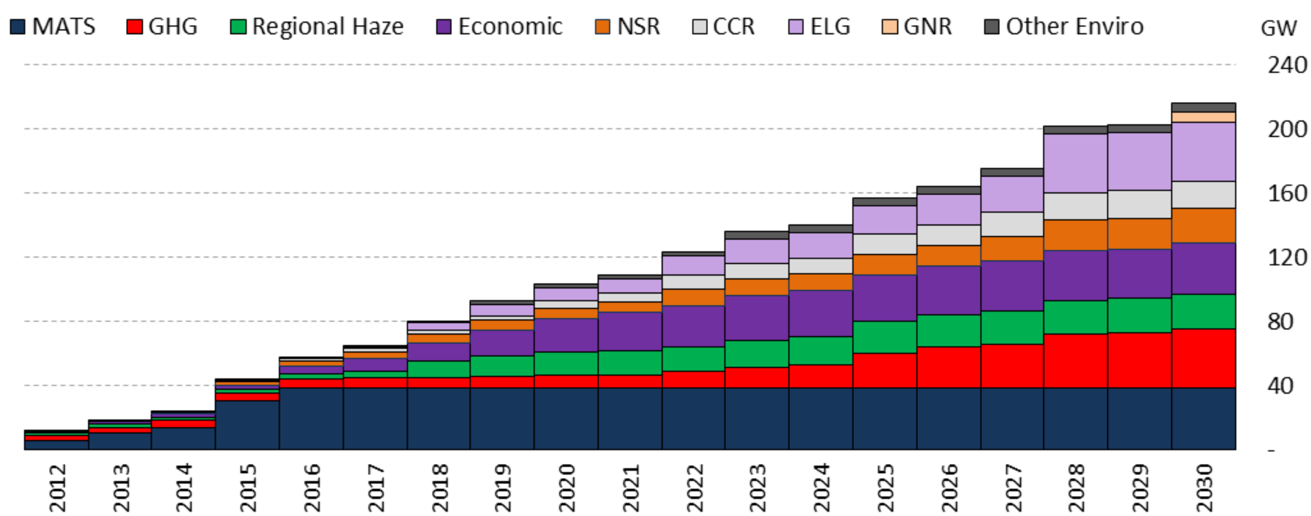
EPA assumes that coal plants with announced plans to retire before 2032 are not affected by the proposed GHG rule but it ignores the reality that coal plant owners have repeatedly changed announced retirement plans for a variety of reasons, including preserving reliability of the power supply system. In the last few years, the previously announced retirements of 23 coal units totaling 8.4 GW have been postponed and one large station (the 1,146 MW Coal Creek plant in North Dakota) has been sold to a new owner with plans to operate the plant indefinitely. Thus, the impact of the proposed GHG rule on the power industry is likely to be greater than assumed by EPA in its analysis.

Causes of Coal Plant Retirement

One of the recurring arguments of the EPA in its proposed GHG rule is the minimal impact of the rule due to the advanced age of the U.S. coal fleet. According to EPA, since historically, most coal plants have retired at around 50 years of operating life, almost all coal plants will retire in the absence of the proposed rule due to plants reaching their respective 50-year mark. EPA has confused correlation and causation. EVA's analysis shows that the primary cause of coal plant retirements since 2010 is the effect of new environmental regulations and enforcement actions by EPA that have ***nothing to do with the age of the power plant***. Because a large majority of coal plants in the country were built between 1960 and 1980, it is true that most of the coal plants that closed in the last decade (2012 – 2022) were about 50 years old. However, these plants did not close ***because*** they were 50 years old – they closed because of the large cost to comply with new EPA regulations. In its Power Sector Trends Technical Support Document, EPA ***never once mentions*** the impact of its many new environmental regulations on causing the retirement of coal plants over the last decade.

To accurately analyze and highlight the cause of coal plant retirements around their 50-year mark, Energy Ventures Analysis (EVA) analyzed the retirement cause of all coal-fired steam EGUs since 2010, including planned retirements through 2030. **EXHIBIT *3*** shows historical and planned coal retirements by primary cause, while **EXHIBIT *4*** shows additional detail of the age of the coal-fired steam EGU at retirement by cause and the corresponding capacity by retirement cause category.

EXHIBIT 3: COAL CAPACITY RETIREMENTS BY PRIMARY CAUSE



[3] The limitation on any increase in emissions could affect these plants and restrict them from normal fluctuations in operation and maintenance activities.

EPA's 2011 Mercury and Air Toxics Standards (MATS) rule was the dominant driver of coal plant retirement in the 2010s, accounting for over 40% of the 93 GW of retirements that occurred during that decade. Between 2020 and 2030, company and state CO_2 reduction goals are the primary driver of coal plant retirements, accounting for almost one-quarter of the roughly 123 GW of historical and planned retirements during the 2020s. EPA's 2016 Effluent Limitation Guidelines (ELG) account for approximately another quarter of coal retirements during the same period.

EXHIBIT 4: COAL RETIREMENT AGE BY CAUSE

Retirement Cause	EGU Age at retirement *(years)*					Capacity
	Min	Avg	Max	StDev	Range	*(GW)*
Economic	5	46	89	16	84	31.4
Regional Haze	8	46	68	10	60	21.7
GHG	20	52	73	12	53	36.8
Other Enviro	20	52	69	12	49	5.5
MATS	27	56	71	7	44	38.6
NSR	28	56	69	9	41	21.7
ELG	30	50	65	8	35	36.6
CCR	31	53	64	7	33	17.1
GNR	45	62	77	12	32	6.5
Total	**5**	**52**	**64**	**12**	**59**	**215.9**

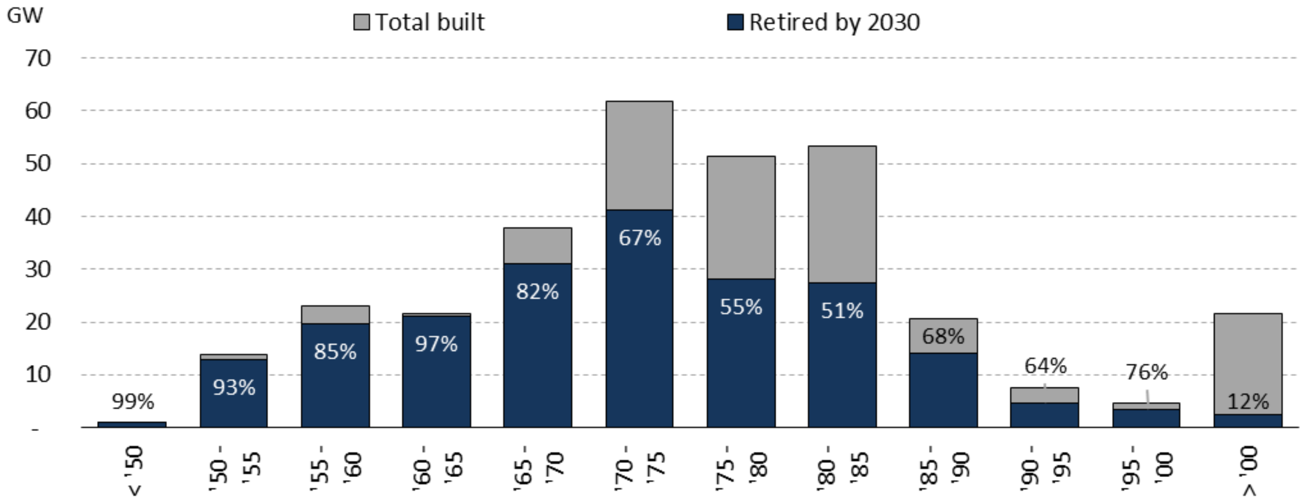
Note: GHG = company greenhouse gas goals, NSR = New Source Review, ELG = 2016 Effluent Limitation Guidelines, CCR = 2016 Coal Combustion Residuals Rule, GNR = 2023 Good Neighbor Rule

According to EVA's analysis, the average coal plant retirement age for the almost 216 GW of coal capacity analyzed is around 52 years, with the minimum age at just five years and the maximum age at 54 years, resulting in a standard deviation of 12 years and a range of 59 years. However, these statistics vary greatly by retirement cause. Generally, coal retirements in the "Economic" and "GHG" (company greenhouse gas reduction goals) categories are at the discretion of the coal-fired steam EGU owner or operator, while "MATS" (Mercury and Air Toxics Rule), “Regional Haze” (federally - imposed implementation plans to force reductions in power plant emissions), "NSR" (New Source Review litigation brought by EPA for alleged major modifications of existing coal plants), "ELG" (Effluent Limitations Guidelines limiting waste water discharges from coal plants), "CCR" (Coal Combustion Residuals rule ending the use of wet ash ponds) and "GNR" (Good Neighbor Rule limiting interstate transport of ozone precursor emissions) are plant-specific as they pertain to specific emission or environmental control retrofits needed to comply with the new EPA regulations. As shown in **EXHIBIT *4***, the range and standard deviation of coal plant age at retirement caused by the EPA regulations are significantly narrower than for retirements at the discretion of the plant owner. This is due to the similar plant configuration of coal-fired steam EGUs built around the same time, driven primarily by changes in New Source Performance Standards (NSPS).

Newer coal plants have been less likely to retire than older plants – not because they are newer, but because they already had installed expensive environmental controls and were not severely affected by the host of new regulations promulgated by EPA since 2011. One of the most important factors was the 1977 NSPS that required SO_2 emission reductions of 90% for new coal-fired power plants from an uncontrolled level for high-sulfur coals. As a result, coal plants that started construction after 1977 designed to consume higher-sulfur coal were built with SO_2 scrubbers and were able to comply with the 2011 MATS rule with minimal capital investment. Older plants built before 1979 without SO_2 scrubbers were faced with substantial capital investments to comply with EPA's MATS rule, which many chose to avoid by retiring or converting to natural gas. In fact, 99% of the coal-fired EGUs that retired due to MATS were built before 1979, before the impact of the 1977 NSPS that required SO_2 scrubbers on new coal plants.

Coal plants have proven to run efficiently and reliably past the 50-year operating threshold analyzed by EPA. **EXHIBIT *5*** shows the coal-fired steam EGU capacity by online year period and the percentage of capacity planned for retirement by 2030.

EXHIBIT 5: COAL CAPACITY BY ONLINE YEAR & 2030 RETIREMENT STATUS

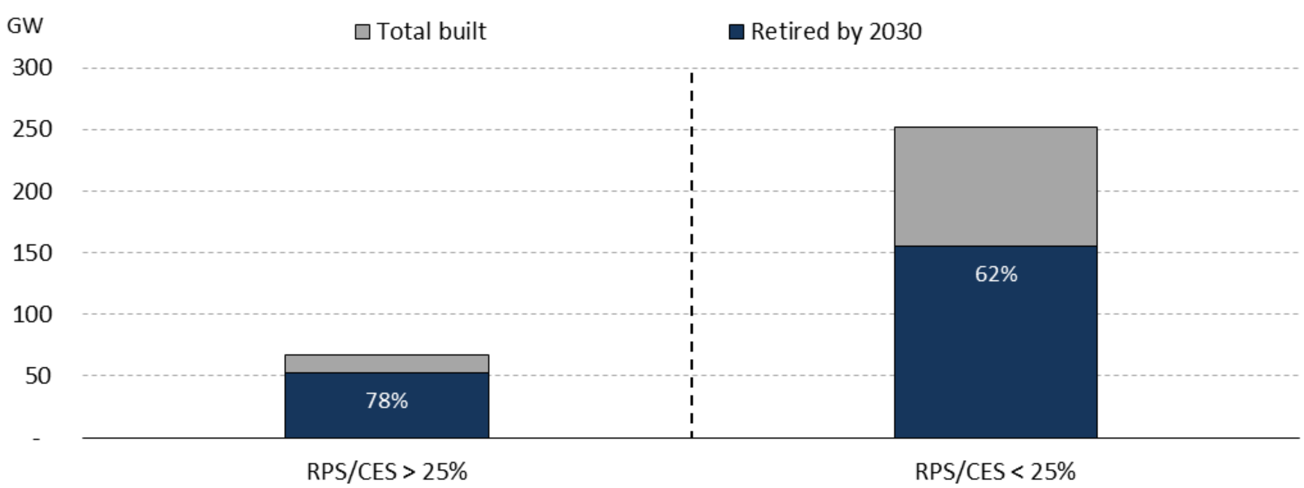


Source: EIA Form-860 data, EVA PPTS

About two-thirds of all coal-fired steam EGUs built in the U.S. were built before 1980 and will be 50 years or older by 2030. **Over half of the coal plants that have no plans to retire by 2030 will be at least 50 years old.** In fact, three of the oldest coal plants in the country, Kyger Creek (963 MW built in 1955), Clifty Creek (1,173 MW built in 1955/56), and Shawnee (1,206 MW built in 1953-55), currently do not have planned retirements before 2030 and will, therefore, be over 75 years old by the end of this decade.

Besides the emission and environmental control equipment already in place at coal-fired steam EGUs, their respective location also has a much greater influence on their retirement date, especially during the 2020s. Many of the announced coal plant retirements during the 2020s are driven by company decisions to reduce greenhouse gas emissions or to comply with state Renewable Portfolio Standards (RPS) or Clean Energy Standards (CES). **EXHIBIT *6*** shows the amount of coal plants built and planned to retire by 2030, categorized by RPS/CES percentage requirements. A high percentage of coal plants located in states with high requirements to reduce GHG emissions plan to close over the next decade.

EXHIBIT 6: HISTORICAL/PLANNED COAL RETIREMENTS BY STATE RPS/CES REQUIREMENTS

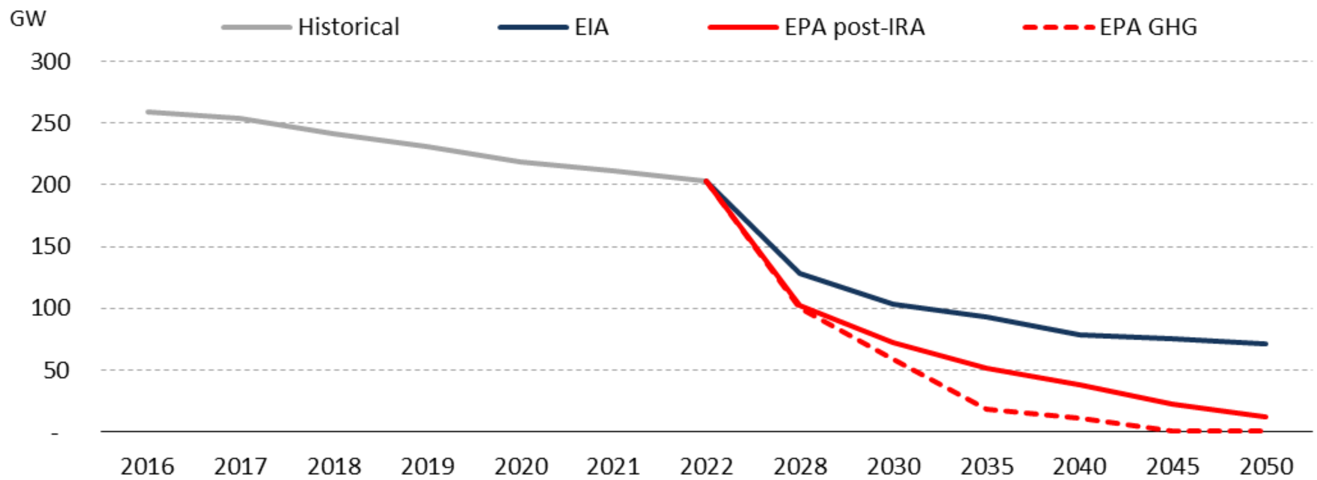


Source: EIA Form-860 data, EVA RPS/CES Tracker

78% of the total installed coal capacity in states with RPS or CES requirements greater than 25% are or will be retired by 2030, respectively. On the other hand, only 62% of coal capacity in states with RPS/CES requirements of less than 25% will be retired by 2030. Financial subsidies given to renewable energy projects and public pressure influencing state legislation requiring the closure of in-state coal-fired steam EGUs are the primary reasons for this significant discrepancy.

As discussed in further detail later in this report, it is unlikely that almost all coal capacity will be retired by 2050, absent any additional EPA regulations as projected by the EPA in its IPM reference and GHG rule scenarios. **EXHIBIT *7*** shows the remaining operating coal capacity in EIA's AEO2023 reference case and EPA's IPM reference and GHG rule scenarios.

EXHIBIT 7: REMAINING COAL CAPACITY BY U.S. AGENCY & SCENARIO



Source: EIA Form-860, EIA AEO23, EPA IPM GHG modeling results

One of the primary reasons the EPA shows little impact of its proposed GHG rule is the massive amount of coal plant retirements occurring in EPA's reference case. In both scenarios, operating coal capacity declines to roughly 100 GW. Although coal plant retirements are accelerated in EPA's GHG scenario, by 2050, less than 5% of the 2022 operating coal capacity remains in both scenarios. Conversely, in EIA's 2023 Annual Energy Outlook's (AEO) reference case, over 70 GW, or about 35% of the 2022 operating coal capacity, is projected to remain operational. In summary, federal environmental regulations and state policies are the primary driver behind coal retirements, not the age of the plant.

Analysis of Natural Gas Co-Firing as a Best System of Emissions Reduction

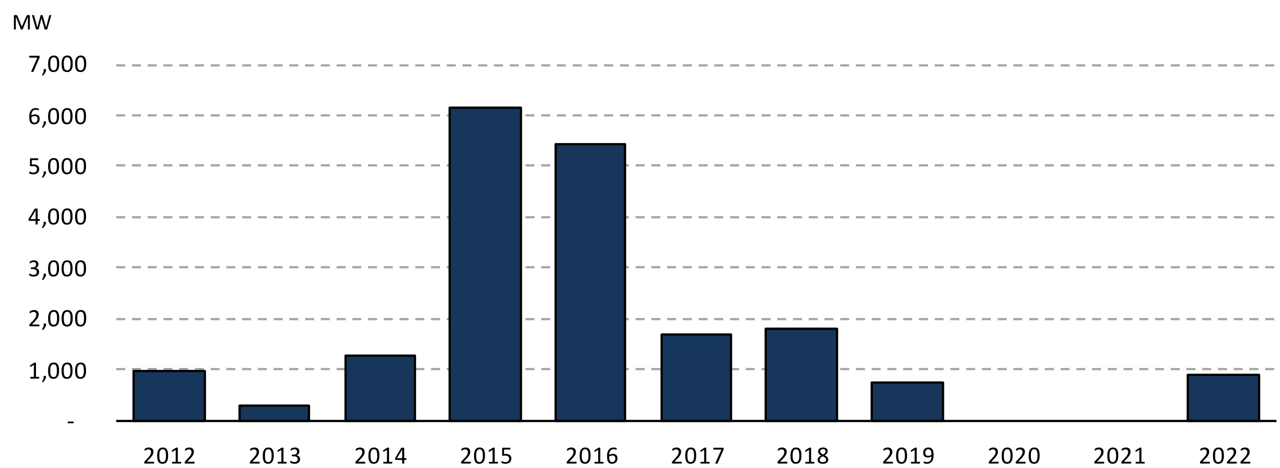
In its GHG rule proposal, the EPA evaluated co-firing natural gas at various rates as a BSER for coal-fired steam EGUs and deemed it adequately demonstrated, widely available, and cost-appropriate to be considered BSER for coal-fired steam EGUs in the medium-term subcategory, i.e., coal units with federally enforceable retirements before January 1, 2040.

Coal-to-gas boiler fuel conversions or natural gas co-firing has been or is used successfully at a small number of current or previous coal-fired steam EGUs. However, natural gas co-firing does not meet the requirement of being widely available for use by the 107.6 GW coal fleet (that does not plan to retire before 2032) because: 1) most of the coal fleet is located a long distance from pipeline gas supply infrastructure and storage, so this technology is not cost-appropriate for most of the coal fleet; 2) the process of approval for the required pipelines by FERC and subsequent litigation will take much longer than required by EPA to use the co-firing technology for compliance; and 3) EPA has not analyzed the ability to supply the large increase in demand for natural gas if the coal fleet were to adopt the gas co-firing technology for compliance.

Analysis of Historical Coal-to-Natural Gas EGU Conversions

Since 2012, almost 20 GW of previous coal-fired steam EGUs have converted to burn natural gas exclusively, as shown in **EXHIBIT *8***. However, most of these historical coal-to-natural gas conversions occurred in 2015 and 2016, the years that were the compliance deadline for EPA's MATS rule. Only five coal-fired steam EGUs totaling less than 900 MW have been converted from coal to gas since 2019.

EXHIBIT 8: HISTORICAL COAL-TO-NATURAL GAS CONVERSIONS



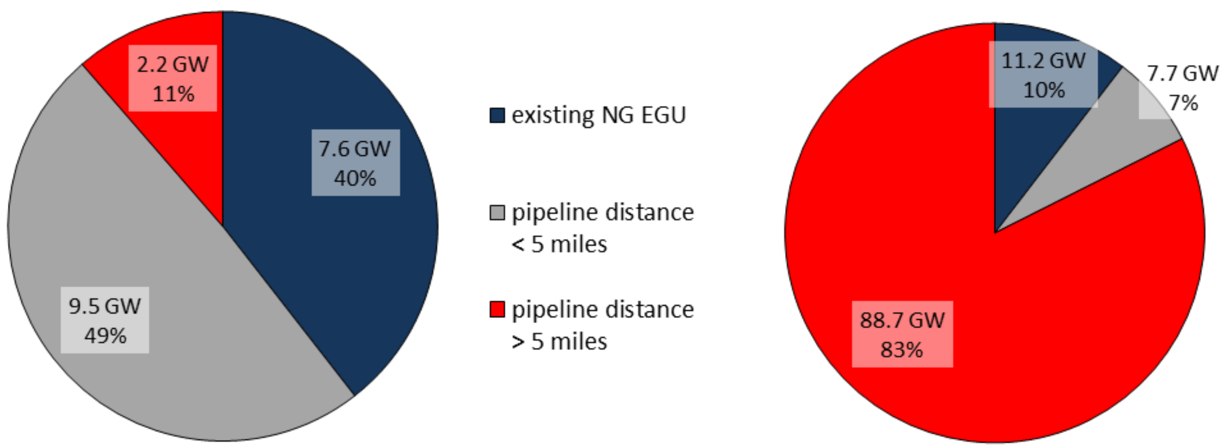
Source: EIA Form860 data

There are two primary reasons that made coal-to-natural gas conversion the preferred MATS compliance strategy for these coal-fired steam EGUs: (1) proximity to existing natural gas infrastructure, which minimized the capital cost to connect to natural gas supply, and (2) low capacity factors, which made other compliance options cost-prohibitive on a levelized cost basis (i.e., $ per MWh).

The capacity factor of a power plant has a significant impact on the economics of operating on coal vs. natural gas. Coal steam plants have much higher non-fuel operation and maintenance costs than steam plants operated on natural gas (including costs for coal handling, boiler operations, emission controls, and CCR facilities). These higher O&M costs can be offset by typically lower fuel costs for coal compared to natural gas, but when the coal plant is operated at a low capacity factor, the high non-fuel O&M costs are much more expensive on a $ per MWh basis. The capacity factors of the coal plants that converted to natural gas were much lower than average for the coal fleet. During the year prior to their conversion, the 20 GW of coal-fired steam EGUs that were converted to natural gas had an average capacity factor of 34%. In comparison, the average capacity factor in 2021 for the 107 GW without a retirement announced before 2032 had an average capacity factor of 54% or 20 percentage points higher than the historical coal-to-gas conversion.

Second, almost 90% of the 20 GW of coal-fired steam EGUS that have converted from coal to natural gas either had existing natural gas-fired EGUs on site or were located close to (within five miles) existing natural gas supply infrastructure, as shown in **EXHIBIT *9***. Only 2.2 GW, or 11% of the previously converted EGUs, were located more than five miles from the existing natural gas supply infrastructure. The average distance from the closest natural gas pipeline for the converted EGUs without existing natural gas generators on site was 4.2 miles.

EXHIBIT 9: EXISTING NATURAL GAS INFRASTRUCTURE FOR HISTORICAL (LEFT) AND POSSIBLE FUTURE (RIGHT) CONVERSIONS



Source: EVA analysis of historical coal-to-gas-conversions

Source: EIA Form-860 data + EPA IPM reference case documentation (Table 5.21)

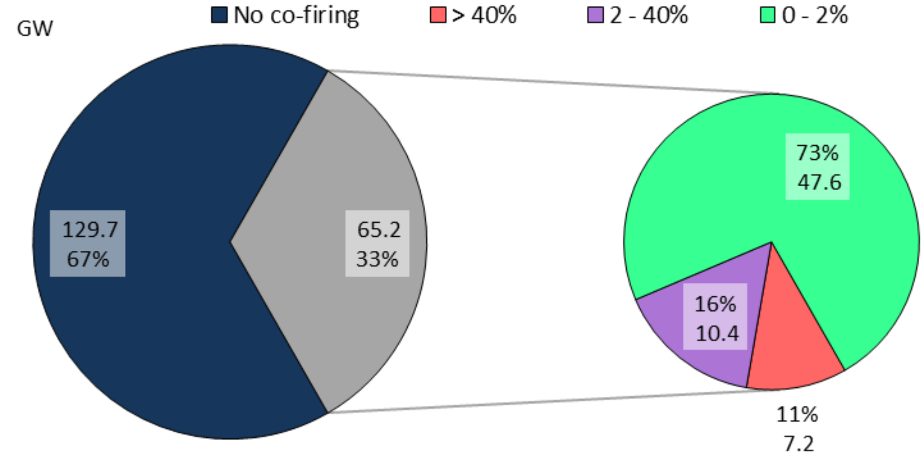
Conversely, of the 107.6 GW of coal-fired steam EGUs without a retirement before 2032, only 11.2 GW or 10% are co-located with existing (or new) natural gas-fired EGUs, and only 7.7 GW or 7% of capacity are located within five miles of existing natural gas supply infrastructure. Almost 90 of the 107 GW are located more than five miles away from such infrastructure, according to EPA's analysis.[4]

Current Natural Gas Use in Coal-Fired Steam EGU Operations

Currently, three different forms of natural gas co-firing are used during the operation of existing coal-fired steam EGUs in the U.S.: (1) dual-fuel firing of either coal or natural gas within the steam boiler system for full-load electric generation, (2) natural gas co-firing in primarily coal-fired boiler systems for full load electric generation, and (3) natural gas use as a startup fuel to bring the burner system up to temperatures to support coal firing (all coal boilers use natural gas or oil as startup fuel). As shown in **EXHIBIT *10***, about one-third of currently operating coal-fired steam EGUs are using natural gas to some degree in their respective operations.

[4] https://www.epa.gov/system/files/documents/2023-05/Table%205-21%20Cost%20of%20Building%20Pipelines%20to%20Coal%20Plants%20in%20EPA%20Platform%20v6%20Post-IRA%202022%20Reference%20Case%20%281%29.xlsx

EXHIBIT 10: 2021-22 AVERAGE NATURAL GAS CO-FIRING % AT EXISTING COAL-FIRED STEAM EGUS



Source: EIA Form-923 data

However, almost three quarters or 47.6 GW of the 65.2 GW of coal-fired steam EGUs that currently use some form of natural gas in their operations only use it for startup operations. While these plants have an existing connection to the local natural gas supply grid, the connection is unlikely to be able to support the natural gas supply levels required to support a co-firing of 40% natural gas annually on a heat input basis at these coal-fired steam EGUs. The use of natural gas for startup requires a small heat input for flame ignition at low loads and does not require large volume gas supply systems, including the pipeline capacity and pressure for operating at full load.

Out of over 430 coal-fired steam EGUs in operation at the beginning of 2023, only ten (11%) had achieved the 40% natural gas co-firing percentage on average during 2021 and 2022, as the EPA proposes in its GHG rule. **EXHIBIT *11*** shows additional details for these ten coal-fired steam EGUs.

EXHIBIT 11: 2021-22 COAL-FIRED STEAM EGUS WITH AT LEAST 40% NG CO-FIRING

Utility	Plant & Unit Name	State	Capacity *(MW)*	Online Date	Planned Retirement	2021-22 avg. NG Co-fire %
Duke Energy	Cliffside 6	NC	844	Dec-12	Dec-48	71.3%
Gainesville, FL	Deerhaven 2	FL	232	Oct-81	Dec-31	68.7%
Dominon SC	Cope 1	SC	415	Jan-96	Dec-30	62.4%
Talen Energy	Brunner Island 2	PA	363	Sep-65	Dec-27	53.3%
Duke Energy	Belews Creek 2	NC	1,110	Dec-75	Dec-38	52.2%
Duke Energy	Belews Creek 1	NC	1,110	Aug-74	Dec-38	50.9%
Duke Energy	Marshall 3	NC	658	May-69	Dec-34	48.4%
Talen Energy	Brunner Island 1	PA	306	May-61	Dec-27	43.9%
Talen Energy	Brunner Island 3	PA	742	Jun-69	Dec-27	42.7%
Duke Energy	Cliffside 5	NC	544	Jun-72	Dec-26	40.5%

As shown in the Exhibit, five of the 10 coal-fired steam EGUs that have co-fired 40% or more natural gas on an annual basis (the minimum amount required by EPA for this BSER) during 2021 and 2022 are owned by Duke Energy and are located at its Belews Creek, Marshall[5], and Cliffside (James E. Rogers Energy Complex) power stations. Duke Energy invested over $283 million ($58.6/kW) to enable its eight coal-fired steam EGUs to co-fire at least 40% (Cliffside 5) and up

[5] Duke Energy's Marshall units 1, 2, and 4 co-fired 36.9%, 18.9%, and 37.0% natural gas, respectively.

to 100% natural gas (Belews Creek 1&2, Cliffside 6). The projects took approximately three years for just the boiler conversions.[6] This time does not include the time to construct a large-diameter pipeline to connect to a major pipeline system to be capable of supplying enough gas to support full load operation.

These ten coal units, along with other coal units co-firing natural gas at a rate less than 40% annually on a heat input basis, have shown the capability to burn 100% natural gas for at least a few hours during 2021 and 2022 outside of boiler startup operation. For example, according to hourly gross generation and emissions data reported by plant owners and operators to the EPA as part of the Clean Air Market Program Data (CAMPD[7]) service, Big Bend unit 4, a primarily coal-fired steam EGU owned by Tampa Electric and located outside Tampa, Florida, burned 100% natural gas for 1,319 out of its 6,303 (~21%) hours of operations in 2021 at an average boiler load level of 40%. Due to its higher boiler load (average 80% during 2021) when burning 100% coal, Big Bend's annual natural gas co-fire percentage on a heat input basis during 2021 was 12.2%, according to EIA Form-923 data[8]. While it will likely be possible for units like Big Bend 4 to maintain an annual natural gas co-firing rate of greater than 40% on a heat input basis, other units that either use natural gas only on a minimal basis during boiler startup or not all will be faced with significant capital investments and extensive planning, permitting, and construction timelines to enable natural gas co-firing percentages compliant with EPA's proposed GHG rule.

Analysis of Natural Gas Supply Infrastructure

As discussed previously, since 2012 almost 20 GW of coal-fired steam EGUs converted to using 100% natural gas, while another subgroup of EGUs (e.g., Duke's Belews Creek, Marshall, and Cliffside plants) significantly expanded their natural gas co-firing capabilities. Although these conversions have proven that it is technically possible to retrofit a coal-fired steam EGU to use 40% or more of natural gas on an annual heat input basis, EPA has not accounted for significant uncertainty regarding the availability and costs associated with the natural gas supply infrastructure needed to supply the additional fuel to the remaining coal fleet.

In order to qualify as a BSER under the CAA, the corresponding technology needs to be available to all affected EGUs at reasonable or comparable costs. Recently, adding the necessary natural gas supply infrastructure to new natural gas -fired EGUs has proven extremely difficult, costly, and time-consuming. As shown in **EXHIBIT *8***, of the 20 GW that previously converted from coal to natural gas, only 11%, or 2.2 GW, needed to build natural gas pipeline laterals greater than five miles in length. Conversely, almost 90 of the 107 GW that are currently planned for operations beyond 2031 are located more than five miles away from the closest major interstate natural gas pipeline system, with some projects estimated to need more than 270 miles of additional pipeline infrastructure.

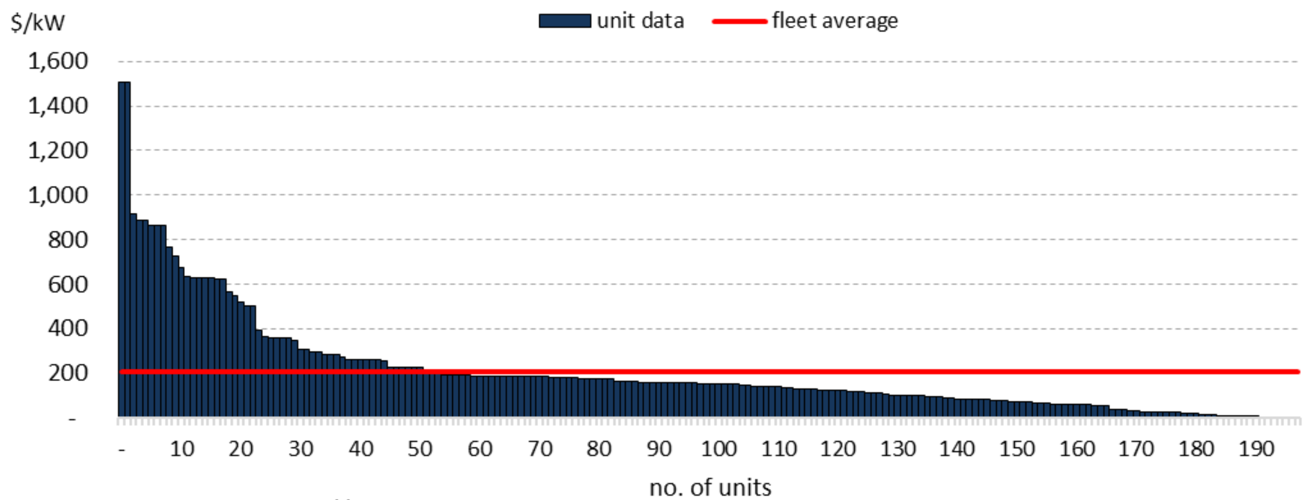
When estimating the pipeline size and associated costs with co-firing 40% natural gas at coal-fired steam EGUs, the EPA assumed pipeline size equivalent to 60% of the net summer generating capacity at each coal-fired steam EGU.[9] Therefore, if operating at 100% boiler load, the EPA limited the maximum use of natural gas at the EGU to 60%. As a result, the EPA estimated the average fleet-wide cost for the natural gas pipeline laterals needed to supply the retrofitted coal-fired steam EGUs with the adequate natural gas supply at $92/kW.

However, analysis of hourly generation data of existing coal-fired steam EGUs that co-fire natural gas for significant periods of time shows that these EGUs have co-fired 100% natural gas even at baseload operations (> 80% capacity factor) for significant periods of time during 2021 and 2022. Being able to co-fire 100% natural gas even at high boiler load levels is necessary for these boiler fuel retrofits to become economically viable. Limiting natural gas co-firing to 60% at baseload levels significantly underestimates the size and associated costs to build the natural gas pipeline laterals needed to supply the retrofitted coal-fired steam EGU with adequate natural gas supply.

[6] https://www.ncwarn.org/2021/04/duke-spending-283m-on-retrofitting-coal-plants/
[7] https://campd.epa.gov/
[8] https://www.eia.gov/electricity/data/eia923/
[9] EPA GHG Mitigation Measure for Steam EGUs TSD.

A more representative value for the costs associated with adding adequate natural gas supply to existing coal-fired steam EGUs to enable significant amounts of natural gas to be co-fired at the site is included in EPA's Integrated Power Modeling (IPM) v6 documentation. In Table 5.21 of EPA's IPMv6 documentation, the EPA estimated the cost of pipeline laterals needed to convert existing coal-fired steam EGUs to enable 100% natural gas co-firing. **EXHIBIT *12*** shows the natural gas pipeline lateral cost on a unit level for the remaining 96 GW that currently do not have an adequate natural gas supply to the site.

EXHIBIT 12: EPA-ESTIMATED NATURAL GAS PIPELINE LATERAL COST BY UNIT

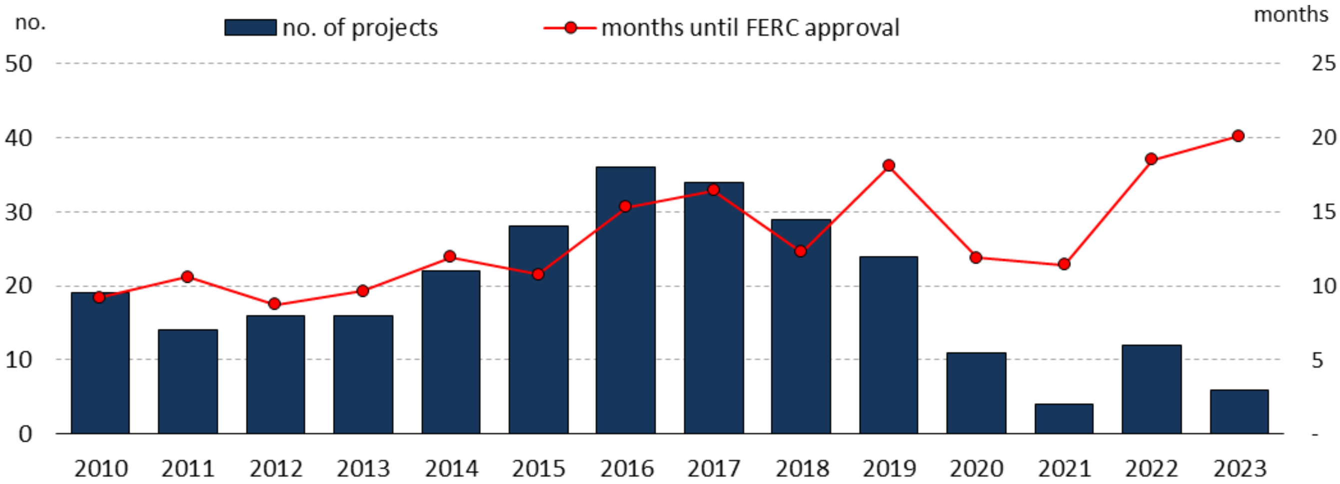


Source: EPA IPMv6 Documentation Table 5.21

According to EPA's analysis, the fleet-wide average to add sufficient natural gas lateral capacity to enable these plants to co-fire 100% natural gas for significant periods of time at full load is $208/kW, more than double what the EPA estimated in its technical support document accompanying the proposed GHG rule. In comparison, adding selective catalytic reduction (SCR) emission control equipment, one of the most expensive coal plant retrofits, to reduce NO_x emissions from coal plants costs roughly $200-250/kW.

Besides underestimating the costs associated with adding sufficient natural gas lateral capacity to the remaining coal-fired steam EGU fleet in 2030, the EPA also underestimated the time it takes to get adequate new natural gas pipeline capacity planned, permitted, and built in time for January 1, 2030, compliance deadline. **EXHIBIT *13*** shows the number of new natural gas pipeline projects approved by the Federal Energy Regulatory Commission (FERC) by approval year and the average number of months the approved projects waited for final FERC approval.

EXHIBIT 13: FERC-APPROVED INTERSTATE PIPELINE PROJECTS BY YEAR AND DURATION OF APPROVAL



Source: FERC natural gas pipeline approval database

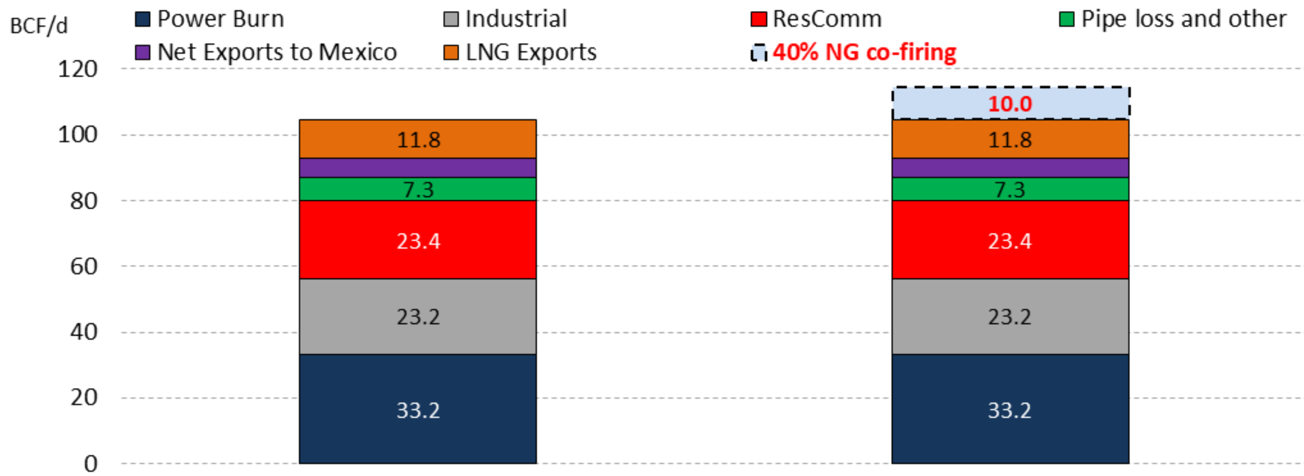
Excluding the COVID-19-impacted years of 2020 and 2021, the FERC approval process for new pipeline projects has consistently increased since 2010. In 2010 the average project took ten months from FERC application to approval. In comparison, the average project approved in 2023 spent over 20 months in the FERC approval process. Increased public scrutiny and opposition to new pipeline projects in the U.S. (e.g., Atlantic Coast, Mountain Valley, Keystone XL, Dakota Access), resulting in protracted litigation and delays, has led to a significant increase in approval time for new pipeline projects.[10]

Besides the increased length of FERC approval, the commission also approved fewer projects each year since its peak in 2016. In 2016, FERC approved 36 new natural gas pipeline projects. In 2022, the commission only approved 12 such projects. Assuming every coal-fired steam EGU planned for operation beyond 2031 utilizes the 40% natural gas co-firing option, more than 100 new natural gas pipeline laterals and possible FERC approvals are needed to accommodate this wide-scale project retrofit. Therefore, FERC would need to approve over 33 projects per year between 2027 and 2029 for coal plants to meet EPA's compliance deadline of January 1, 2030. Based on recent trends in the FERC approval timeline and the number of projects approved, it is highly unlikely for this ambitious timeline to succeed.

Additionally, converting the entire remaining coal-fired steam EGU fleet to allow for 40% natural gas co-firing on an annual basis would add a tremendous amount of natural gas demand to the U.S. natural gas industry, as shown in **EXHIBIT *14***. EPA fails to consider the impact of this increased demand on natural gas supply and prices. Co-firing 40% of the coal fleet would increase domestic demand for natural gas by as much as 10% and would likely affect gas prices for all consumers.

[10] The high-profile Mountain Valley Pipeline project, which is intended to support increased demand for natural gas in the South Atlantic states applied for FERC approval in October 2015. It took FERC 24 months to issue the Certificate of Public Convenience and Necessity. After eight years of hearings and litigation, as well as an Act of Congress, the pipeline still has not received all final court approvals. https://www.mountainvalleypipeline.info/overview/

EXHIBIT 14: 2022 U.S. NATURAL GAS DEMAND & POTENTIAL GAS CONSUMPTION FROM 40% CO-FIRING



Source: EVA Monthly NG Price Outlook

Assuming the 107 GW of coal capacity currently planned to still be in operation after 2031 elect to retrofit and co-fire 40% natural gas, the resulting annual natural gas demand would surpass 10 billion cubic feet per day (BCF/D), roughly equal to the entire U.S. LNG export capacity in 2022 and approximately half of all of the U.S. residential and commercial natural gas demand. An in-depth analysis into the maximum amount of natural gas able to be produced and transported based on the possible maximum amount of natural gas consumed by these retrofitted coal-fired steam EGUs by Jan. 1, 2030, is needed to show that 40% natural gas co-firing is indeed widely available and technically feasible for the entire remaining coal fleet and can, therefore, reasonably be considered a BSER.

EPA's analysis of gas co-firing as BSER does not consider the effect on the entire gas supply system. Converting a significant amount of the coal fleet to natural gas co-firing will require the natural gas supply system to invest in increased gas storage capability, expand interstate pipeline systems, and support the simultaneous need to supply residential demand and power generation during winter storms. As recently shown during Winter Storms Uri and Elliott, the natural gas supply system has not been capable of supporting the simultaneous gas demand for heating and power with the current power fleet. Conversion of coal to natural gas generation will further strain system reliability.

Overview and Analysis of EPA's Power Sector Model Modeling Assumptions and Results

As part of its proposed GHG rulemaking, the EPA included extensive power sector modeling results in the rule docket. Similar to previous regulatory action, the EPA uses a form of ICF's Integrated Planning Model (IPM), a multi-regional, dynamic, and deterministic electric resource capacity expansion model (CEM), to estimate the likely impacts of its rulemaking and the associated costs and benefits of the proposed or finalized rulemaking. This section examines some of the key assumptions and modeling results that have profound impacts on the effect of the proposed GHG rule on the U.S. electric power sector.

Due to last-minute changes to the proposed GHG rule requested by the Biden Administration after the EPA submitted the rule proposal to the Office of Management and Budget (OMB), none of the initial power sector modeling results the EPA published with the proposed rule on May 23, 2023, included all the compliance requirements the EPA set forth in its rule proposal. On July 7, 2023, the EPA subsequently released a new subset of power sector modeling results, which included a new baseline or reference case (post-IRA case) with increased liquified natural gas (LNG) export assumptions in line with EIA's 2023 Annual Energy Outlook (AEO), as well as an updated GHG rule scenario that included all compliance requirements (GHG case). All results presented in this section refer to these two new sets of modeling results released earlier this month.

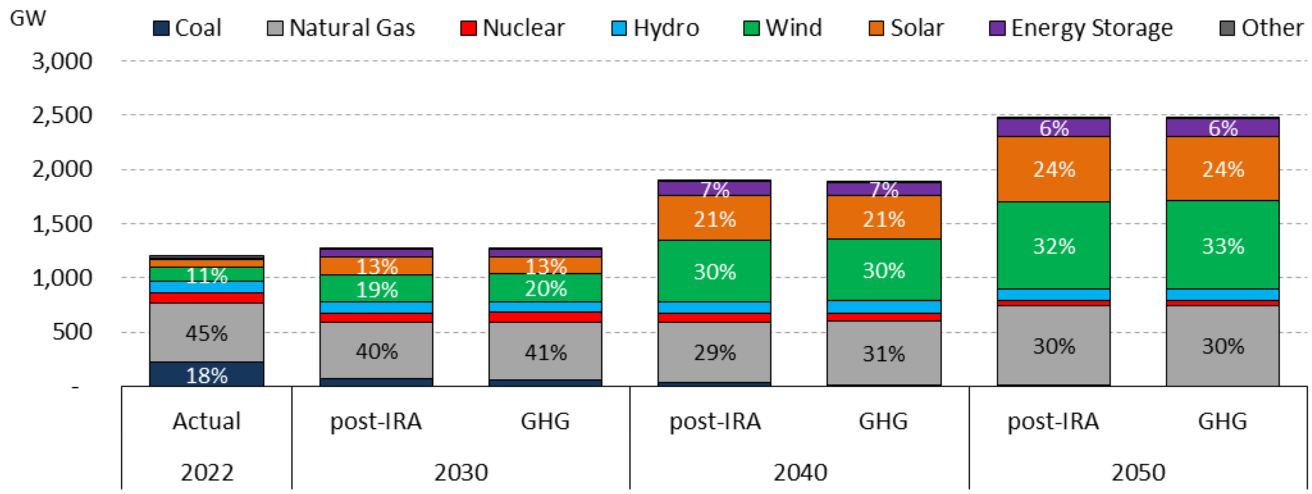
Projected Generation & Capacity Mix Changes

As described in the documentation, *"IPM is a dynamic linear programming model that generates optimal decisions under the assumption of perfect foresight. It determines the least-cost method of meeting energy and peak demand requirements over a specified period. In its solution, the model considers a number of key operating or regulatory constraints that are placed on the power, emissions, and fuel markets. The constraints include, but are not limited to, emission limits, transmission capabilities, renewable generation requirements, and fuel market constraints."*[11] Both the reference case and GHG case include the tax incentives of the 2022 Inflation Reduction Act (IRA) as well as EPA's 2023 transportation sector GHG rule resulting in electric vehicles accounting for over two-thirds of new vehicle sales by 2032. **EXHIBIT *15*** and **EXHIBIT *16*** show the resulting capacity and generation mix for the U.S. Lower-48 states[12], respectively. Data tables supporting the Exhibits are located in the Appendix.

[11] https://www.epa.gov/power-sector-modeling/post-ira-2022-reference-case

[12] EPA's modeling only covers the Continental United States. However, EPA's proposed rule impacts existing and fossil fuel EGUs in Hawaii and Alaska, which will also see increased compliance and operating costs as a result.

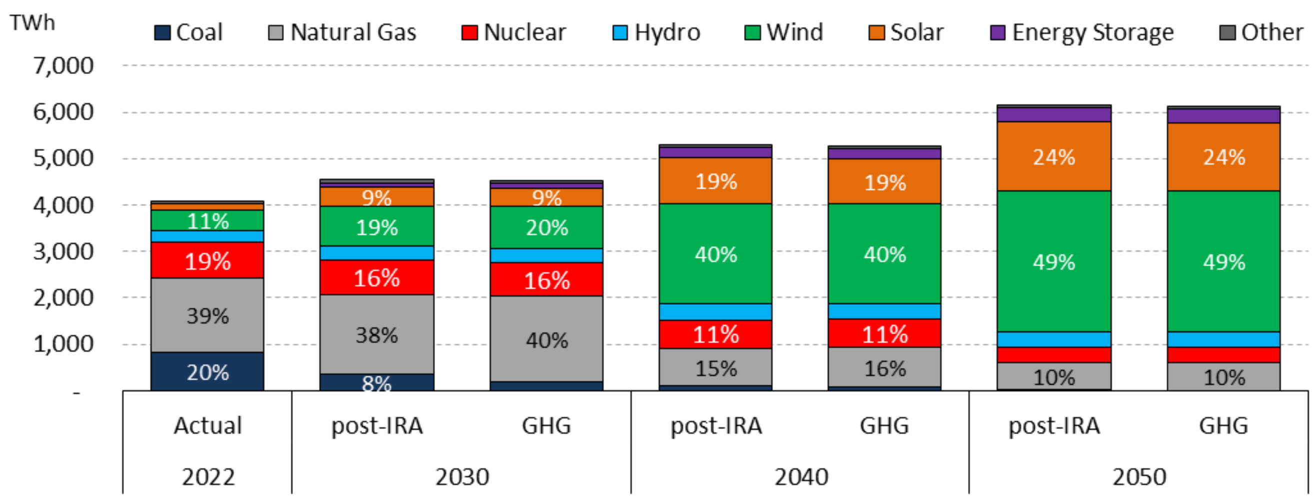
EXHIBIT 15: LOWER-48 CAPACITY MIX BY FUEL TYPE BY SCENARIO



Source: EPA IPM modeling results (released July 7, 2023)

In 2022, natural gas-fired EGUs accounted for over 45% of the total installed capacity of 1,206 GW in the continental U.S., while coal, wind, and solar power plants accounted for 18%, 11%, and 5%, respectively. Unsurprisingly, due to immense tax incentives included in last year's IRA, EPA's reference case shows a tremendous buildout of wind and solar power plants over the next 25+ years. By 2040, the EPA projects wind capacity to grow fourfold from 138 GW in 2022 to 568 GW, or roughly 23 GW (~17% of today's **total** installed wind capacity) per year. Conversely, the EPA projects solar capacity to grow sixfold from 66 GW in 2022 to 407 GW just 18 years later, an average of 18 GW of new solar capacity per year. By 2050, intermittent wind and solar capacity is projected to account for 57% of the total installed electric generating capacity in the U.S.

EXHIBIT 16: LOWER-48 GENERATION MIX BY FUEL TYPE BY SCENARIO



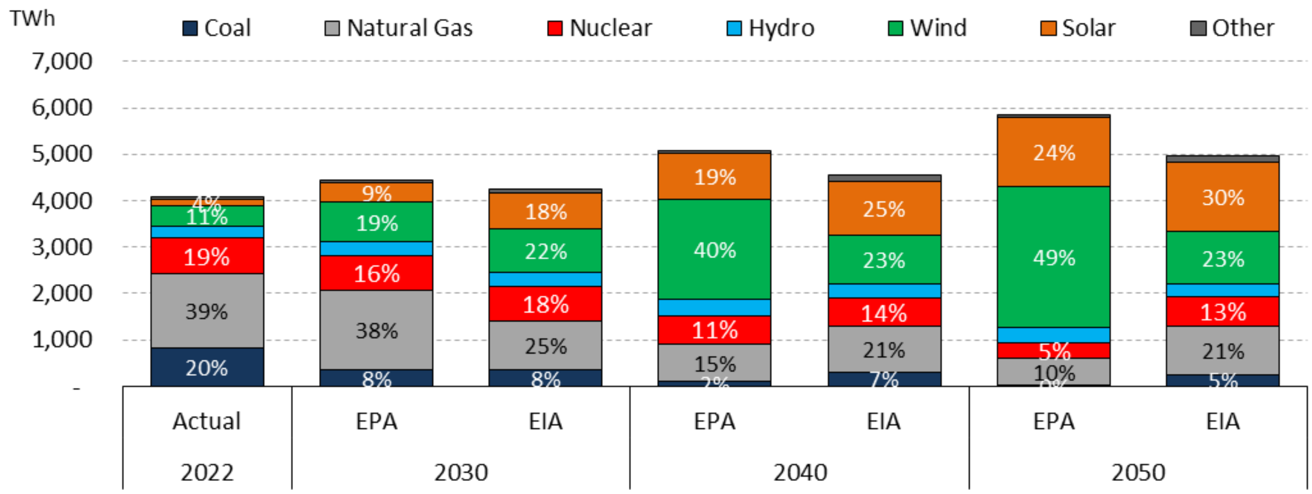
Source: EPA IPM modeling results (released July 7, 2023)

Due to the inclusion of EPA's GHG rule affecting the U.S. transportation sector and the subsequent shift from internal combustion engine vehicles to electric-powered ones, the EPA projects total electricity demand to grow from 4,075 TWh in 2022 to 6,149 TWh by 2050, an increase of over 50%. EPA relies on the massive buildout of wind and solar resources driven by the tremendous tax incentives of the 2022 IRA, and projects that intermittent generation from wind and solar will account for almost three-quarters of total electricity generation by 2050. Fossil fuel generation, which virtually consists of natural gas generation only by 2050, will account for just 10%, compared to almost 60% in 2022.

Notably, the high-level results of EPA's reference case and its GHG rule case are virtually identical, with only minor differences, as shown in the charts above. Both scenarios are dominated by intermittent resources and are retiring the vast majority of dispatchable fossil fuel generation. In both scenarios, almost all coal-fired steam EGUs will be retired by the 2040 IPM model year. Natural gas-fired EGUs are projected to provide only a small share of generation, primarily to balance out the intermittency of renewable energy.

Compared to EIA's latest Annual Energy Outlook (AEO 2023), EPA's renewable energy expansion and fossil fuel reduction are significantly more aggressive. **EXHIBIT *17*** shows the generation mix for EPA's post-IRA reference case and EIA's AEO2023 reference case. Both scenarios include the 2022 IRA. However, EIA's reference case does not include EPA's proposed transportation sector GHG case. Nonetheless, EIA's reference case shows significant electricity demand growth due to the higher adoption of electric vehicles driven primarily by tax incentives included in the IRA[13].

EXHIBIT 17: GENERATION MIX COMPARISON BETWEEN THE EPA & EIA REFERENCE CASES



Source: EPA IPM modeling results (released July 7, 2023) & EIA AEO 2023 reference case

Although EIA's AEO2023 reference case includes the same tax incentives included in the IRA, its modeling shows a less aggressive adoption of intermittent renewable resources than EPA's post-IRA reference case.[14] In EIA's AEO2023 reference case, wind generation grows from 434 TWh in 2022 to 1,132 TWh in 2050, accounting for roughly one-quarter of electric generation. Conversely, solar generation is projected to grow from 144 TWh in 2022 to 1,490 TWh in 2050, accounting for approximately 30% of total electric generation in that year. Overall, intermittent generation accounts for just over 50% of total electric generation in 2050 in EIA's AEO2023 reference case.

Renewable Energy Performance in the EPA IPM

EPA relies on the massive buildout of intermittent resources in its IPM reference and GHG scenarios. However, realistic modeling results are essential to properly understand the true impact of EPA's proposed GHG rule. One of the major improvements ICF/EPA made to the IPM since 2016 was the inclusion of declining capacity credits for wind, solar, and battery storage resources as their market penetration increases. However, due to the underlying model design, EPA's IPM fails to properly account for any renewable energy curtailments due to higher market penetration of wind and solar resources and their underlying generation profiles.[15] The curtailment of renewable generation occurs when the amount

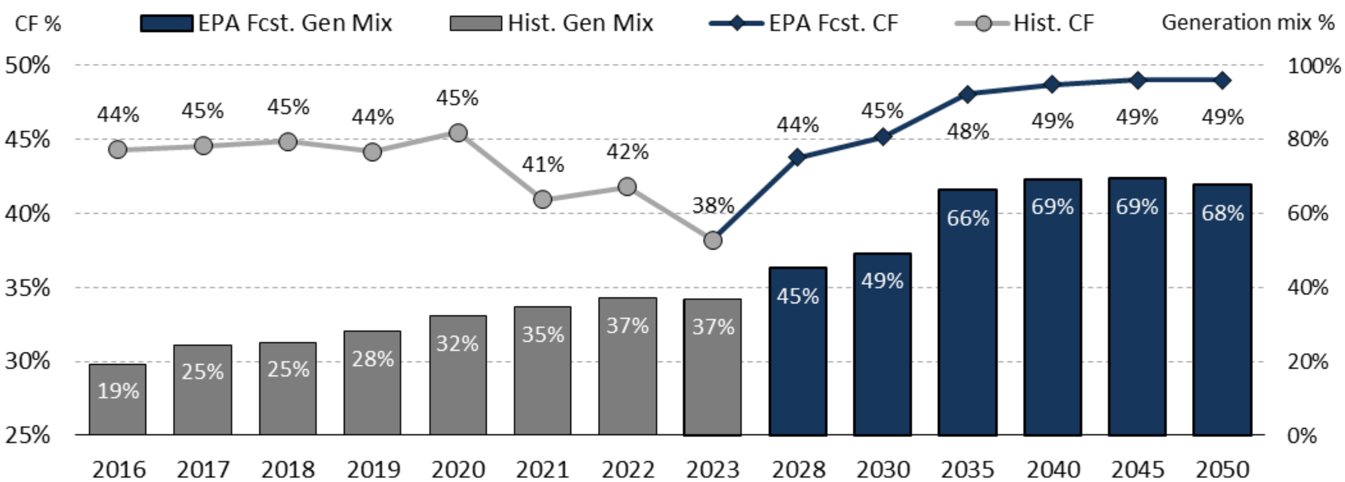
[13] https://www.eia.gov/outlooks/aeo/IIF_IRA/

[14] EIA's AEO2023 reference case does not include all the recent EPA regulations affecting the coal fleet but does include the same incentives for new renewable power generation.

[15] Curtailment occurs when the independent system operator must restrict generation from otherwise economic power plants to maintain stability of the power grid. The large increase in renewable power generation is causing curtailment of renewable generation to increase, yet this is not reflected in the capacity factors in the IPM model.

of renewable power supply exceeds electricity demand, after accounting for dispatch of other power plants needed for reliability. The growing curtailment of renewable generation in many power markets shows that the capacity factors for renewables assumed in EPA's IPM are unrealistic in conjunction with the projection of a massive increase in renewable capacity. **EXHIBIT *18*** shows the historical and forecasted wind generation mix percentage and historical and forecasted wind fleet-wide capacity factors in the Southwest Power Pool (SPP), which is the power region with the highest penetration of wind power generation.

EXHIBIT 18: HISTORICAL & FORECASTED SPP WIND GENERATION MIX & CAPACITY FACTOR



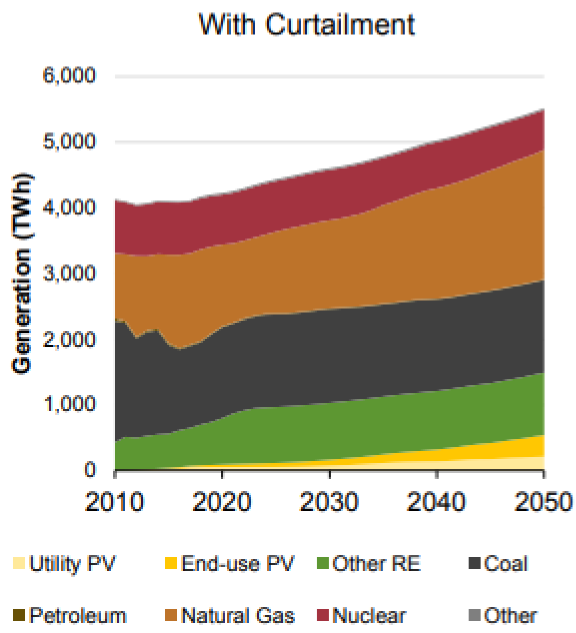
Source: EIA Form-923 & Form-860 data & EPA IPM reference case results; Note: 2023 data through July 2023

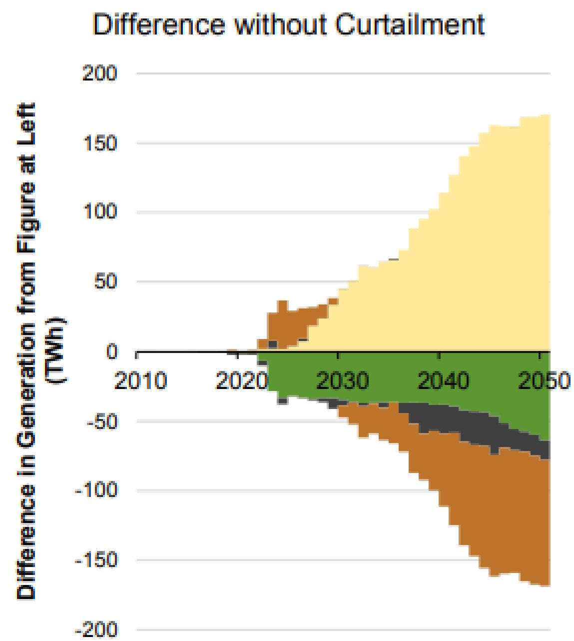
Based on historical data, wind generation tends to peak during early morning and late-night hours during the day and in Spring and Fall months over the course of the year. These periods of peak wind generation performance also coincide with the lowest electricity demand, both over the course of the day and over the entire year. Without massive energy storage or transmission expansions, an increasing amount of wind generation is disconnected, i.e., "curtailed", from the electric power grid to balance supply and demand at any given time properly. As shown in **EXHIBIT *18***, as wind's generation share in SPP increased from 19% in 2016 to 37% in 2022, the fleet-wide average annual capacity factor for wind turbines in SPP dropped from a peak of 45% in 2018 to 41% in 2021 and just 38% during the first seven months of 2023. In its post-IRA reference case, the EPA projects wind's generation share in SPP to continue to expand to just under 70% by 2040, while the fleet-wide wind capacity factor increases to never-seen-before levels of 49%, despite the much higher wind penetration rate in SPP. The actual decline of capacity factors for wind generation in SPP from 45% to 38% shows that a realistic forecast of wind capacity factors would be for this decline to continue as wind's generation share increases – not jump to a new high of 49% as assumed in the IPM forecast.

As the National Renewable Energy Laboratory (NREL) stated in its 2017 report[16], *"If VRE curtailment is not represented in a capacity expansion model, that model is likely to overestimate the value of VRE technologies."* As an example, NREL references EIA's modeling results, highlighting the impact of curtailment on the forecasted generation mix between the major fuel types in the U.S. **EXHIBIT *19*** shows the charts referenced in NREL's report. These charts show that the failure to account for curtailment results in an overestimate of generation by renewable sources and an underestimate of generation by other sources, primarily fossil fuel.

[16] NREL, Variable Renewable Energy in Long-Term Planning Models, 2017. https://www.nrel.gov/docs/fy18osti/70528.pdf

EXHIBIT 19: 2017 NEMS GENERATION MIX IN THE REFERENCE CASE WHEN CURTAILMENT IS INCLUDED (LEFT) AND THE DIFFERENCE IN GENERATION WHEN CURTAILMENT IS NOT INCLUDED (RIGHT)

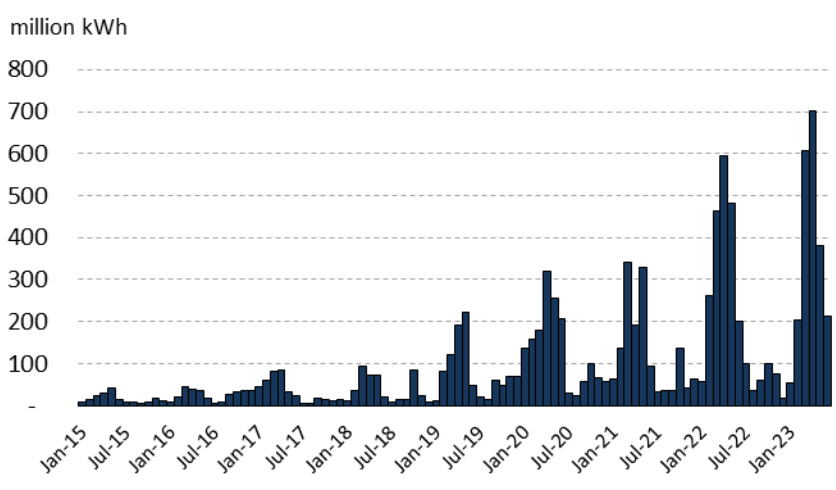




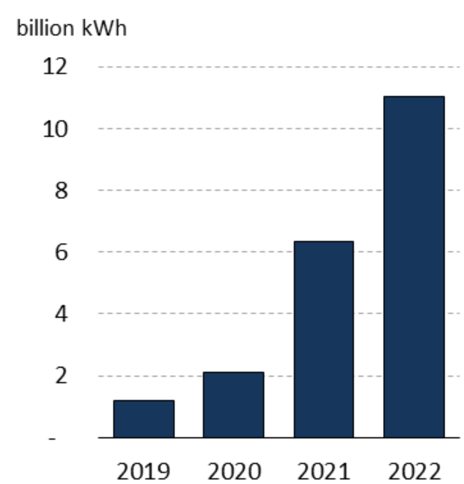
According to NREL and EIA's modeling results, not correctly accounting for renewable energy curtailment overstates the amount of electricity generated by these resources and understates the amount of electricity that other resource types need to meet. The aforementioned example of curtailment impact was based on 20% renewable penetration. According to NREL, *"[…] the impact of curtailment in higher penetration scenarios would be even more significant."*

Over the last decade, as intermittent resources like wind and solar have increased their market penetration in most markets across the country, so have their curtailments in these markets. **EXHIBIT *20*** shows the monthly curtailment of wind and solar resources in CAISO and the annual curtailment of wind resources in SPP.

EXHIBIT 20: MONTHLY WIND & SOLAR CURTAILMENTS IN CAISO (LEFT) & ANNUAL WIND CURTAILMENTS IN SPP (RIGHT)



Source: CAISO



Source: SPP

Both CAISO and SPP markets have seen exponential growth in renewable energy curtailments over the last five years as their contribution has increased. In both markets, wind and solar accounted for less than 40% of total generation in 2022. By 2040, the EPA projects their market share to grow to 61% in CAISO and 92% in SPP.

Renewable energy curtailment can also be considered "stranded" renewable electricity. Two solutions to reduce the amount of "stranded" or curtailed renewable electricity is to install energy storage projects such as lithium-ion batteries or increase transmission capacity to surrounding regions where the additional renewable energy can be consumed. EPA's IPM is capable of increasing both energy storage and transmission capacity. However, EPA's IPM reference case does not include any additional transmission capacity expansion from SPP to its surrounding regions, despite its intermittent renewable energy mix increasing to 92% by 2040. SPP's projected installed energy storage capacity of 1.7 GW in 2040, or 1.6% of total wind and solar capacity, will be inadequate to accommodate renewable generation in SPP in EPA's IPM. Consequently, without properly accounting for renewable energy curtailments or the resulting need for additional energy storage and transmission capacity in its modeling results, the EPA is likely greatly underestimating the reliability, cost, and performance impacts associated with such a high renewable-energy-penetration environment.

Analysis of EPA's Resource Adequacy Analysis Technical Support Document (TSD)

In support of its proposed GHG rule, the EPA also released the Resource Adequacy Analysis TSD[17] discussing the resource adequacy of its proposed rulemaking and its projected impacts on the U.S. electric power sector. Despite its title, this Resource Adequacy Analysis TSD does not properly analyze or highlight any potential reliability issues because of EPA's proposed rulemaking.

First, the EPA did not update the Resource Adequacy Analysis TSD following the release of its updated modeling results, which include all of the compliance requirements proposed by the EPA affecting new and existing fossil fuel-fired EGUs. Since the published Resource Adequacy Analysis TSD is based on incomplete modeling results, its overall results are not applicable to the actual likely impacts of the proposed rulemaking.

Second, the IPM will never output a model result that shows inadequate resources to meet future electricity demand. One of its core constraints, as described in the IPM documentation, is Reserve Margin Constraints. A reserve margin is the amount of excess electric generating capacity available during peak electricity demand hours. Existing and possibly new resources contribute either 100% or a portion of their installed capacity to meet these reserve margin targets. At its core, the IPM aims to meet the electricity demand and reserve margin constraints with the lowest-cost resource mix. As a result, any viable solution of the IPM will result in a resource mix that "adequately" meets the reserve margin and electricity demand constraints inputted into the underlying model. However, resource adequacy does not equal reliability as highlighted by recent events affecting the U.S. electric power markets.

During the winter of 2020/21 and 2022/23, the U.S. experienced two extreme cold weather events, subsequently named Winter Storm Uri (February 2021) and Winter Storm Elliott (December 2022), which drove electricity demand during the winter season to record highs across most parts of the U.S. Even though all major power markets showed an adequate resource mix by way of positive reserve margins ahead of these two powerful winter storms, the U.S. experienced multiple devastating Loss-of-Load events, also known as blackouts, in parts of the country (primarily Texas during Winter Storm Uri and the Southeast during Elliott) and came dangerously close to more widespread blackouts in many other regions. The primary reason for the widespread power outages or near-misses during these storms was the lack of available generating capacity, both fossil and non-dispatchable, as shown in numerous industry reports following the events, including EVA's detailed review of the Operation of the U.S. Power Grid during Winter Storm Elliott[18]. Equipment failures and loss of fuel supply, especially for natural gas plants in Texas during Uri and in PJM and the Southeast during Elliott, resulted in a lack

[17] See https://www.regulations.gov/document/EPA-HQ-OAR-2023-0072-0045.

[18] EVA, "Operation of the U.S. Power Fleet During Winter Storm Elliott, February 2023 https://www.evainc.com/press-releases/eva-winter-storm-elliott-report/ (prepared for America's Power).

of available fossil fuel resources to meet the increased demand. Despite its already low expected contribution during peak demand hours, wind generation in Texas during Winter Storm Uri greatly underperformed, which other resources were unable to offset, resulting in widespread, prolonged power outages in the region. Conversely, during Winter Storm Elliott, wind generators generally overperformed in many parts of the country, highlighting the unpredictability of intermittent resource performance during these extreme weather events.[19]

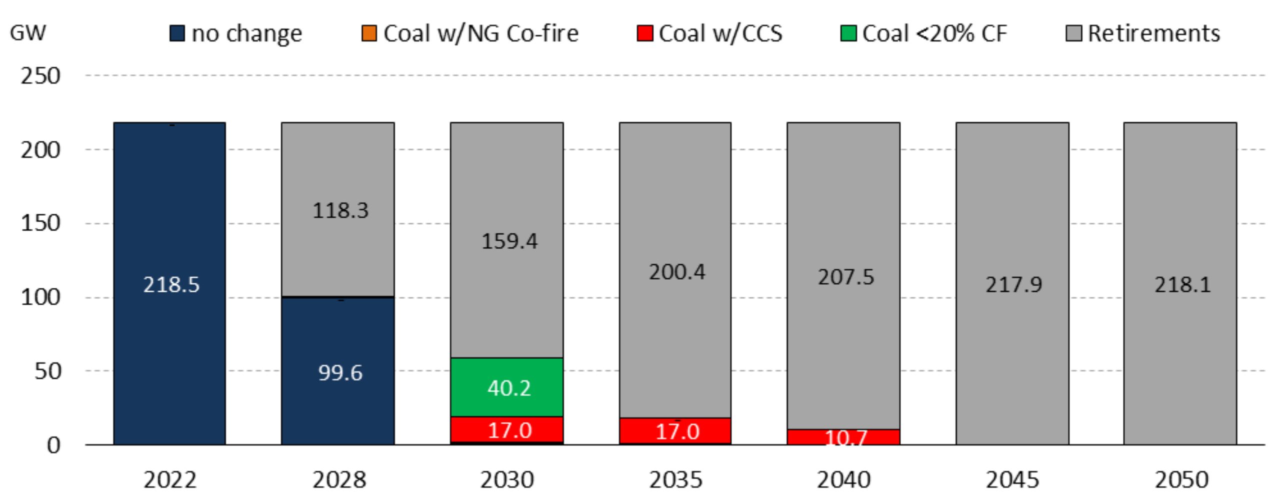
In the aftermath of winter storms Uri and Elliott, independent system operators (ISOs) and the NERC are reassessing how to properly plan and ensure sufficient available resources to meet electricity demand during these extreme weather events. Solutions that are being considered include having different reserve margin targets for different seasons or adjusting the peak capacity credit for natural gas-fired EGUs based on their historical performance and fuel supply status (i.e., higher credits for plants with onsite or firm natural gas supply contracts).

To minimize runtime, the IPM includes peak demand for three different seasons (summer, winter, and winter-shoulder) for each region, while the same region-specific reserve margin is applied to each peak demand. Additionally, the IPM assigns 100% peak credits for all resources except wind, solar, and energy storage, which have less than 100% and declining peak credits based on their respective market penetration in the region. Due to its deterministic nature, the IPM also does not include extreme weather scenarios that could drive material changes in peak and average electricity demand and renewable generation profiles during these events. Although the IPM is a well-respected and often-used capacity expansion modeling platform used for long-term electric power resource planning, it is inadequate to properly assess any potential reliability concerns related to its model results and associated resource mix. EPA forecasts widespread and massive changes likely to occur in U.S. electric power sector mix in its analysis of the 2022 IRA and the proposed GHG rule but fails to properly assess the reliability attributes and issues (such as insufficient transmission capacity and voltage stability) that are likely to arise from them. EPA's IPM is not designed for, and therefore cannot fulfill, the function of analyzing these potential reliability issues.

EPA Projected Coal Unit Compliance with the Proposed GHG Rule

As part of its IPM data output, the EPA included the operating and retrofit characteristics for existing coal plants. **EXHIBIT *21*** summarizes the EPA-modeled compliance strategies exercised by coal-fired steam EGUs in EPA's GHG rule scenario.[20]

EXHIBIT 21: EPA-MODELED GHG RULE COMPLIANCE BY COAL-FIRED STEAM EGUS



Source: EPA IPM GHG case results

[19] *Id.*

[20] Note – EPA's model predicts that less than 1 GW of coal plants will adopt natural gas co-firing as their compliance strategy.

Of the 218.5 GW of coal-fired steam EGUs that operated during 2022, 118.3 or 54% are modeled to retire by EPA's 2028 model year. As mentioned previously, about 105 GW of the 218 GW, or 48%, have previously announced plans to cease coal consumption and switch to natural gas or retire completely. Between the model year 2028 and 2030, the EPA projects an additional 40 GW of coal retirements, most of which have not been previously announced. In comparison, EPA's MATS rule, to date the EPA regulation driving the most coal retirements, resulted in the retirement of 34 GW between 2015-2016, most of which were older and underutilized coal-fired steam EGUs.

As a result of these massive retirements, less than 60 GW of the original 218 GW or 27% are modeled to comply with EPA's proposed GHG rule. Of the 60 GW, over two-thirds, or 40.2 GW of coal capacity, elected to extend their operations to the end of 2034 by limiting their utilization to 20% on an annual basis. 17 GW are modeled to retrofit CCS, while only nine coal-fired steam EGUs (four of which are industrial co-generation plants) totaling less than 1 GW are modeled to co-fire at least 40% natural gas. By model year 2045, less than 500 MW of coal capacity, most of which are units smaller than 25 MW that have no compliance requirements under the proposed GHG rule, remain operational in the U.S. All of the coal units which were modeled to retrofit CCS in 2030 are retired by 2045 as the 45Q tax credit included in the 2022 IRA only provides an $80/tonne CCS credit for the first 12 years of CCS operation (i.e., January 1, 2030, to December 31, 2041). Therefore, EPA's modeling results highlight the questionable cost-effectiveness and availability of both 40% natural gas co-firing and 90% CCS retrofit as BSER for existing coal-fired steam EGUs.

Analysis of Carbon Capture & Sequestration (CCS) as a Best System of Emission Reduction

The current state of carbon capture power plants in North America is limited, with no commercial projects and numerous challenges hindering widespread implementation. Only two demonstration projects in North America have been developed, the Boundary Dam Power Project in Canada and the idled Petra Nova facilities in Texas, USA. One of the primary roadblocks to the development of carbon capture projects is the exorbitant cost of implementing this cutting-edge technology. The high capital investment required for construction, coupled with ongoing operational expenses, laying the pipeline network, and sequestration of the emitted CO_2, as well as significant permitting challenges, pose significant implementation barriers, making carbon capture power plants financially challenging and less economically viable.

The recent enactment of the Inflation Reduction Act (IRA) has renewed and expanded the tax credit incentives pertaining to carbon capture and storage (CCS) efforts. In line with the provisions outlined in the Internal Revenue Code (IRC) section 45Q, the updated legislation introduces enhanced credit values. Specifically, eligible projects capturing and securely storing CO_2 in geologic formations are now eligible for credit values amounting to $85 per tonne. Furthermore, projects that either capture and utilize CO_2 or capture and securely store it in conjunction with enhanced oil recovery (EOR) techniques can avail themselves of credit values of $60 per tonne. These tax credits last for 12 years after operation under the IRA.

Nevertheless, the EPA's proposal has not been met with enthusiasm from utilities operating in the sector. In a recent inquiry conducted by a news agency, ten prominent companies controlling the largest coal and gas fleets in the US were contacted to ascertain their plans regarding carbon capture and storage (CCS)[21]. Surprisingly, aside from three companies, the majority confirmed that they do not currently have any immediate intentions to install CCS technology to curtail carbon emissions from their power plants, despite the available tax credits included in the IRA. This reluctance is evident even in regions where CCS implementation is being aggressively promoted. A Wyoming law passed in 2020, for instance, mandates utilities to adopt CCS on coal plants instead of closing them. However, PacifiCorp, which manages four coal plants in the state under its Rocky Mountain Power subsidiary, informed state regulators earlier this year that it had no plans for CCS and would instead retire the plants[22]. Adding to the skepticism, the U.S. Chamber of Commerce, in its published report of June 2023, expressed the opinion that carbon capture technology is not yet sufficiently developed for widespread adoption, challenging the EPA's claim that CCS meets the "adequately demonstrated" standard and deeming it as "dubious."[23]

Boundary Dam Carbon Capture Project, Canada

SaskPower's Boundary Dam 3 CCS Facility (BD3), situated in close proximity to Estevan, Saskatchewan, Canada, has gained global recognition as the pioneering fully-integrated and full-chain carbon capture and storage (CCS) facility operating in conjunction with a coal-fired power plant. This technologically advanced plant, with a capacity of 115 MW, commenced operations in the fall of 2014, following substantial financial support of $240 million from the federal government, supplemented by undisclosed funding from the provincial government[24]. Despite the considerable acclaim for the plant's capacity to significantly reduce greenhouse gas (GHG) emissions by 1 million tonnes of CO_2 per year, an exhaustive

[21] https://www.eenews.net/articles/epa-says-carbon-capture-is-within-reach-utilities-arent-biting/?utm_medium=email

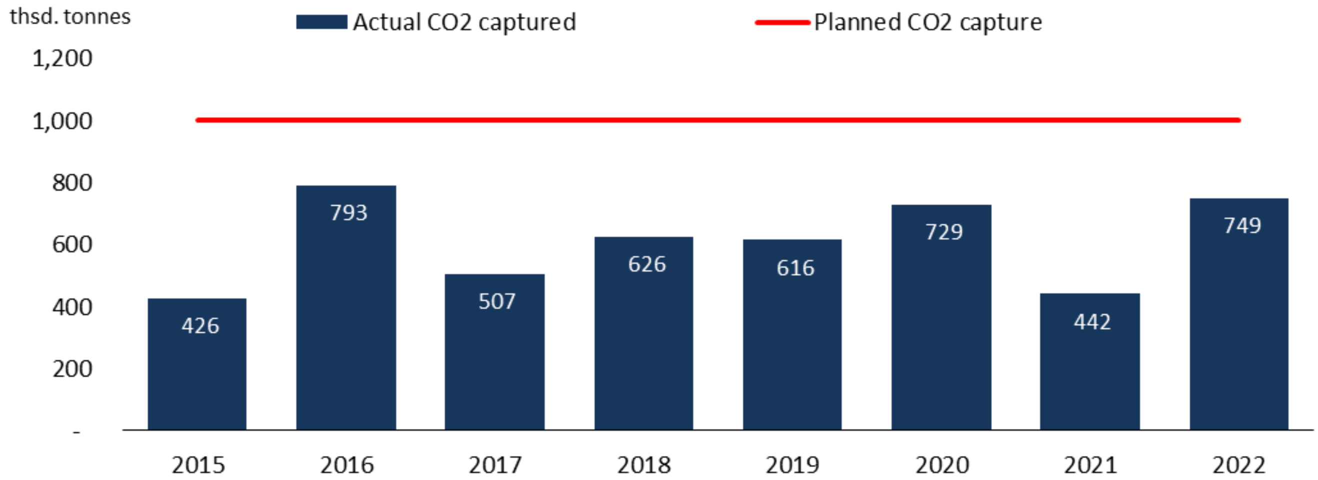
[22] https://www.wyomingpublicmedia.org/natural-resources-energy/2021-01-15/carbon-capture-firms-pursue-power-plant-set-to-retire-though-doubt-remains

[23] https://www.globalenergyinstitute.org/sites/default/files/2023-06/USCC_EPA%20Powerplant%20Rule%20Analysis_2023.FINAL_.pdf

[24] https://www.reuters.com/article/canada-carboncapture/canada-launches-worlds-largest-commercial-carbon-capture-project-idINL2N0RW1D620141001

examination, as illustrated in **EXHIBIT *22*** below, highlights the finding that the plant has failed to attain this notable milestone since its establishment[25].

EXHIBIT 22: ACTUAL VS. PLANNED CO_2 CAPTURE AT BOUNDARY DAM 3



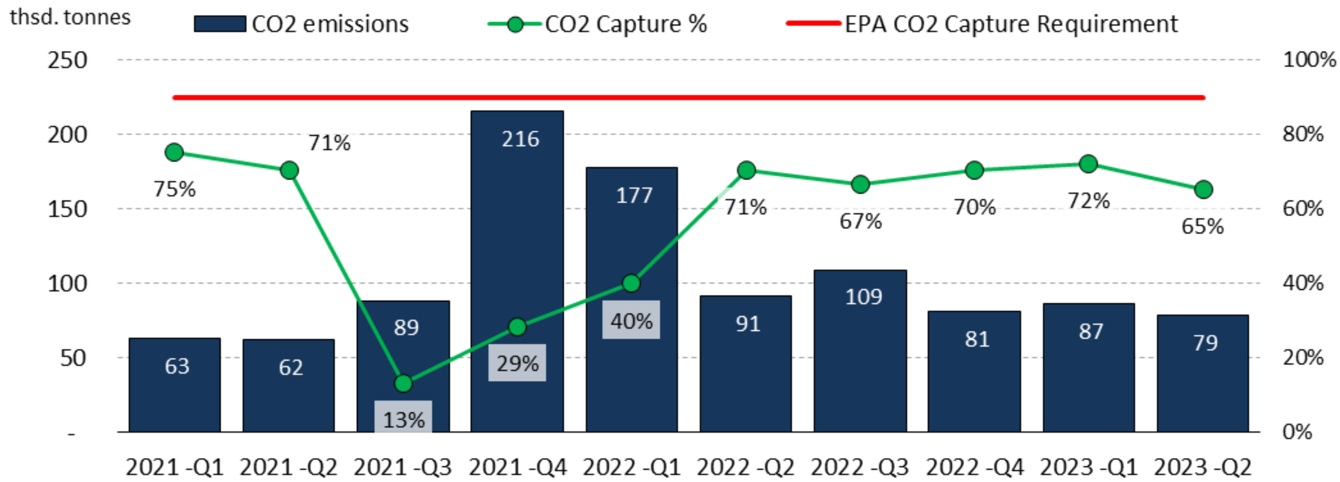
Source: SaskPower Monthly Boundary Dam 3 Status Update

Despite initial claims of a 90% reduction in CO_2 emissions, it reveals inconsistent capture efficiency in recent years, peaking at a maximum of 75%, as shown in **EXHIBIT *23***. Consequently, EPA cannot use this plant as a representative example for larger, conventional power plants required to capture at least 90% of their emitted CO_2 under EPA's proposed emission standards.

Notably, SaskPower CEO Rupen Pandya was quoted in the Wall Street Journal on May 11, expressing that the SaskPower CCS facility would be unable to meet Canada's forthcoming CCS emissions requirement. [26,27] By 2030, Canada's CCS regulations, which differ from the EPA proposal, will mandate a capture rate of 420 tonnes per gigawatt-hour (GWh) of electricity generation. Under the new rule, it translates to 105 tonnes per GWh for US EGUs[28]. Considering the emissions intensity of a conventional lignite coal-fired power plant at 1,100 tonnes/GWh, the corresponding capture obligation would approximate 62%. Failing to meet this lower threshold set by Canadian regulations signifies that attaining 90% CCS, aspired to by the facility and required under EPA's GHG rule proposal, remains unproven.

[25] https://ccsknowledge.com/bd3-ccs-facility
[26] https://www.wsj.com/articles/carbon-capture-is-hard-this-plant-shows-why-ce6e938c
[27] https://www.globalenergyinstitute.org/sites/default/files/2023-06/USCC_EPA%20Powerplant%20Rule%20Analysis_2023.FINAL_.pdf
[28] https://www.federalregister.gov/d/2023-10141/p-1767

EXHIBIT 23: BOUNDARY DAM 3 CO_2 EMISSION & CCS CAPTURE RATE VS. THE EPA REQUIREMENT



Source: SaskPower Monthly Boundary Dam 3 Status Update

EPA's GHG Mitigation Strategies for Steam EGUs TSD mentions that the captured CO_2 from the Boundary Dam plant is either used for enhanced oil recovery (EOR) or stored underground. The success of the Boundary Dam project is attributed, in part, to the conveniently located injection well near the plant (2 km from BD3)[29]. This raises questions about the feasibility of CCS implementation in other regions where suitable geological storage sites may not be as readily available.

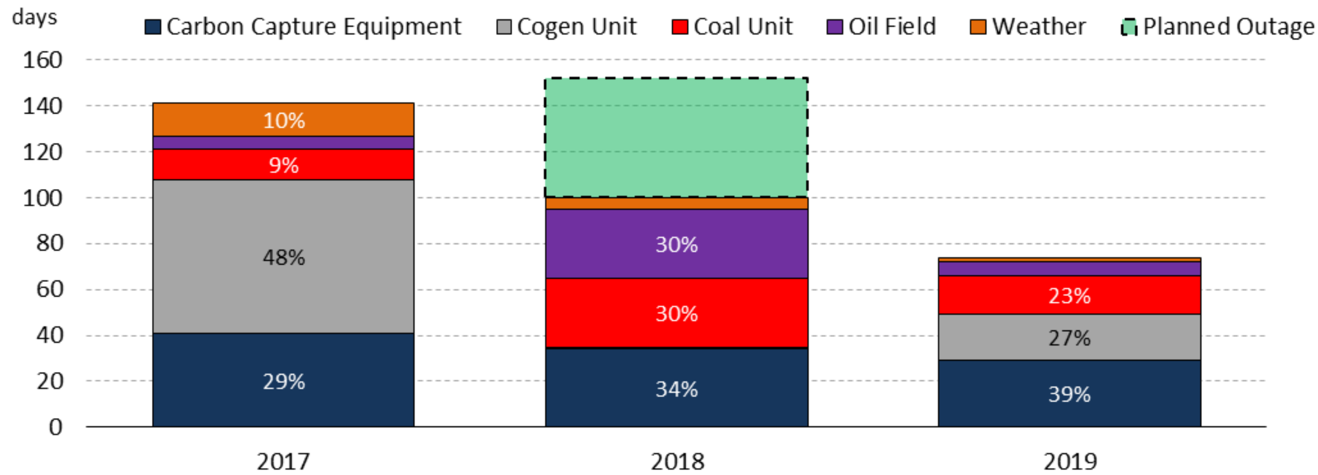
Petra Nova CCS Facility

The Petra Nova Project was a joint venture between NRG Energy, Inc. (NRG) and JX Nippon Oil Exploration Limited (JX) that represented a commercially scaled post-combustion carbon capture project. The 240 MW project was specifically designed to extract and capture CO_2 from the flue gas slipstream of an existing coal-fired unit at NRG's W.A. Parish Electric Generating Station (WAP), located southwest of Houston, Texas. The captured CO_2 underwent a drying and compression process before being transported through an 81-mile pipeline to the West Ranch oilfield (West Ranch) in Jackson County, Texas. At West Ranch, the injected CO_2 served to enhance oil production. The Petra Nova Project, which was valued at approximately $1 billion, received partial funding worth $190 million through a grant from the United States Department of Energy (DOE) under the Clean Coal Power Initiative (CCPI) Round 3[30].

According to a report, since its initiation in 2017, the Petra Nova project encountered significant challenges with its carbon capture facility, resulting in downtime of more than a quarter of the total 367 outage days[31], as shown in **EXHIBIT *24***. **EXHIBIT *25*** provides an additional breakdown of the outage days. Furthermore, the facility fell short of its carbon capture targets by approximately 17%. Over the course of its first three years, it captured 3.8 million short tons of CO_2, failing to meet the developers' initial expectation of 4.6 million short tons.

[29] https://ccsknowledge.com/pub/Factsheets/Factsheet_EOR.pdf
[30] https://www.osti.gov/servlets/purl/1608572
[31] https://www.reuters.com/article/us-usa-energy-carbon-capture-idUSKCN2523K8

EXHIBIT 24: PETRA NOVA CO_2 CAPTURE PROJECT OUTAGES (DAYS) BY COMPONENT - SUMMARY[32]



Source: 2020 U.S. DOE/NETL Report on Petra Nova

EXHIBIT 25: PETRA NOVA CO_2 CAPTURE PROJECT OUTAGES (DAYS) BY COMPONENT - DETAIL

Outage by Component (Total Phase 3)									
	2017			2018			2019		
	Total	Full (Days)	Partial (FDEs)	Total	Full (Days)	Partial (FDEs)	Total	Full (Days)	Partial (FDEs)
CC Facility	41	23	18	34	19	15	29	17	12
Cogen Facility	67	57	10	1	1	0	20	14	6
WAP Unit 8	13	8	5	30	28	2	17	12	5
CO_2 Pipeline	0	0	0	0	0	0	0	0	0
West Ranch	6	0	6	30	13	17	6	4	2
Weather	14	13	1	5	2	3	2	2	0
Planned Outage	0	0	0	52	52	0	0	0	0
Totals	**141**	**101**	**40**	**152**	**115**	**37**	**74**	**49**	**25**

Subsequently, on May 1, 2020, NRG made the decision to idle the facility, citing the adverse economic conditions resulting from the precipitous decline in oil prices triggered by the global impact of the coronavirus pandemic. Ultimately, the project was characterized by its short-lived existence and modest scale, funded by the Department of Energy (DOE), thereby eliciting substantial concerns among stakeholders regarding the economic viability at the commercial scale of a CCS facility. After acquiring NRG Energy's ownership share in Petra Nova in 2022, JX Nippon is now the sole owner of the projects, and announced plans to return the Petra Nova Project to service once the W.A. Parish unit 8 returns to service later this year.[33]

[32] Kennedy, Greg. W.A. Parish Post-Combustion CO2 Capture and Sequestration Demonstration Project (Final Technical Report). United States: N. p., 2020. Web. doi:10.2172/1608572. Page - 41

[33] https://www.reuters.com/business/energy/restart-delayed-texas-coal-unit-linked-petra-nova-ccs-project-2023-08-01/

In addition to these projects, the EPA's mention of ongoing projects assessing the retrofitting of existing coal steam EGUs with CCS technology may seem promising, but a critical examination reveals several concerns. First, these projects are still in their early stages and heavily rely on research and funding opportunities from the DOE.

One notable instance highlighted by the EPA involves an 1,800 MW combined-cycle natural gas power station that plans to incorporate carbon capture technology[34]. This plant, which will require a substantial investment of $3 billion, is currently in the planning phase for construction in West Virginia under the auspices of Competitive Power Ventures. Although this project is ambitious in nature, it is important to note that the information provided thus far is limited to a press release and should, therefore, not be deemed an appropriate example of CCS technology as economically viable and commercially available.

Another project highlighted by the EPA is Project Tundra, which plans to capture 4 million tonnes of CO_2 annually from the Milton R. Young Station. Based on a projected 12-year operational period, with a tax credit of $85 per ton, the project stands to receive a substantial subsidy amounting to $4.08 billion. Critics of the project express concerns over the substantial investment in a plant that is already 50 years old[35]. Moreover, they argue that the subsidy's long-term benefits may be limited, given that the project will cease operations after the 12-year period if the 45Q tax credit is not extended beyond its current term.

EPA also cites the AES Shady Point CO_2 recovery plant in Oklahoma as another example[36]. This facility captured CO_2 emissions from a coal power plant; however, the annual amount recovered amounts to only a few thousand tons, which were primarily utilized in the food and beverage industry. This comparison raises concerns as it does not align with the magnitude of CO_2 emissions typically associated with utility-scale power plants, where the emissions are of significant proportions. Furthermore, the difference in the end use of the 5% captured gas also highlights a disparity between these two scenarios. This power plant has been sold to a local utility which is no longer operating the small carbon capture facility.

Among the CO_2 sequestration projects referenced by the EPA, a notable omission was Southern Company's Kemper County IGCC CCS Project. Initially hailed as the country's pioneering electricity plant utilizing gasification technology to convert coal into syngas while capturing 65% of the carbon emissions, totaling 3.3 million tons per year, the project faced numerous challenges from its inception[37]. Originally scheduled to be operational by May 2014, with an estimated cost of $2.4 billion, the Kemper Project encountered significant delays and complications, ultimately resulting in expenditures surpassing $7.5 billion by June 2017. In an effort to manage escalating costs, a decision was made to transition the plant to burning solely natural gas. The arduous journey of the Kemper County Power Project further manifested when the already constructed infrastructure had to undergo controlled implosion, reducing it to a pile of debris[38].

The Kemper County Power Project's experience serves as a stark reminder of the complexities and uncertainties associated with large-scale CCS initiatives, emphasizing the need for thorough planning, execution, and adaptation throughout the project lifecycle.

[34] https://www.wboy.com/news/doddridge/doddridge-county-commission-approves-pilot-for-3-billion-cpv-project/
[35] https://www.inforum.com/news/north-dakota/project-tundra-carbon-capture-plans-may-not-be-worth-climate-financial-risks
[36] https://www.federalregister.gov/d/2023-10141/p-798
[37] https://ieefa.org/resources/ieefa-us-southern-company-demolishes-part-75-billion-kemper-power-plant-mississippi
[38] https://www.eenews.net/articles/the-kemper-project-just-collapsed-what-it-signifies-for-ccs/

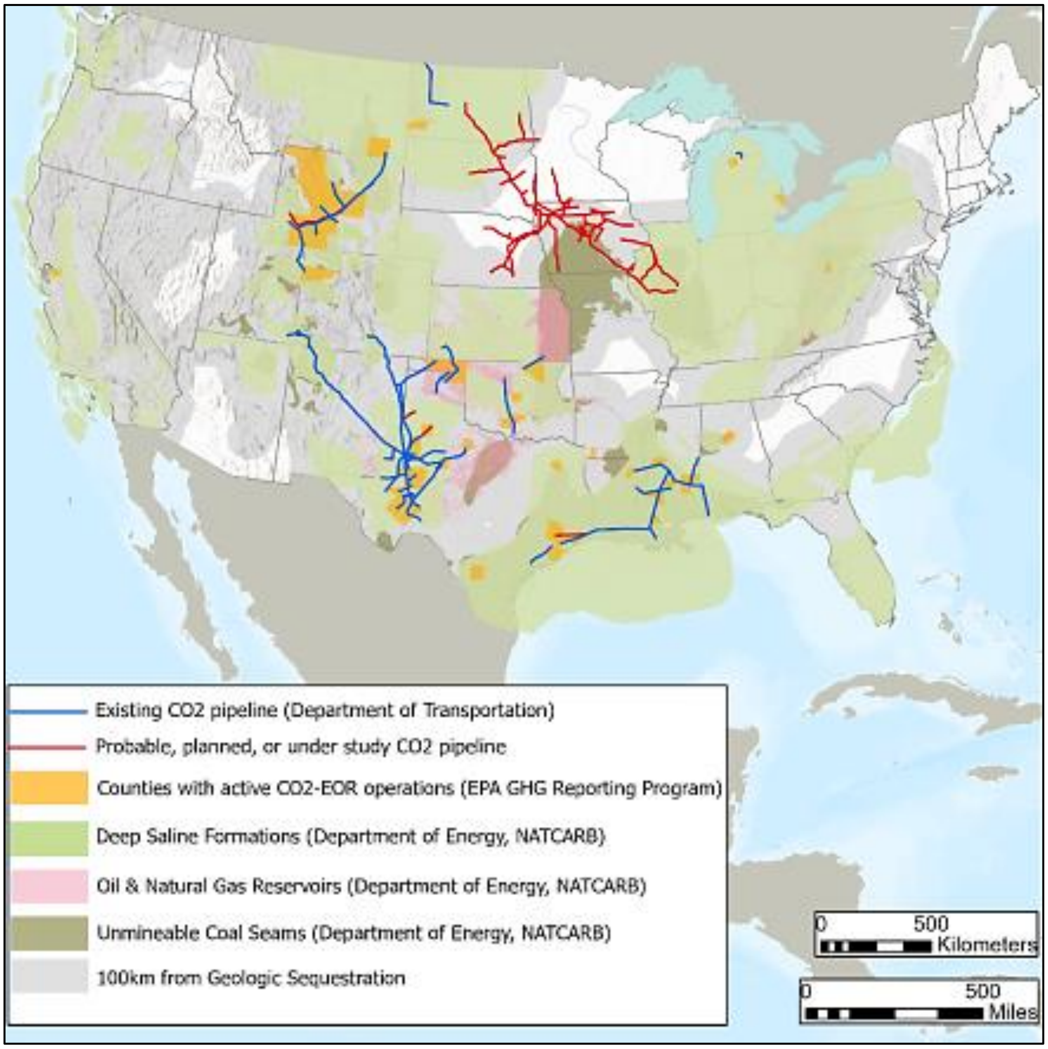
CO_2 Transportation and Storage Challenges

Transportation & Injection

The EPA recognizes the presence of existing CO_2 pipelines in the United States, which cover thousands of miles and facilitate the transportation of both natural and anthropogenic CO_2. The EPA also acknowledges the presence of these pipelines and highlights planned and announced pipeline projects as indicators of infrastructure preparedness.

However, it is important to assess the current pipeline network critically. Presently, CO_2 pipelines are operational in only 11 states, spanning over 5,000 miles which is a mere 13% growth since 2011[39]. **EXHIBIT *26*** provides an overview of the existing and planned CO_2 pipeline capacity in the U.S.

EXHIBIT 26: U.S. CO_2 PIPELINE PROJECTS & SEQUESTRATION FORMATIONS BY TYPE[40]



Although there are 3,895 miles of new CO_2 pipelines planned, which would extend into six additional states, this remains insufficient when compared to the estimated requirement of 68,000 miles identified by a study conducted by Princeton University. [41,42]

[39] https://www.federalregister.gov/d/2023-10141/p-837
[40] https://www.netl.doe.gov/research/coal/carbon-storage/atlasv
[41] https://netzeroamerica.princeton.edu/img/Princeton_NZA_Interim_Report_15_Dec_2020_FINAL.pdf
[42] https://betterenergy.org/blog/carbon-dioxide-transport-101/

The regulation of pipelines involves both state and federal oversight, with states responsible for the pipeline siting and permitting process while federal authorities enforce safety regulations. Due to this dual regulatory framework and the need for approvals across multiple states, the pipeline construction process can be quite lengthy, often taking several years to complete. A prime example is the Cortez pipeline, recognized as the longest CO_2 pipeline, which required a total of 8 years to be finalized, with only 2 years devoted to the actual construction phase[43]. This extended timeline primarily resulted from the state-by-state approval process for the pipeline routing, further emphasizing the time-intensive nature of obtaining necessary permits and clearances across different jurisdictions. Also, it is essential to recognize that the presence of CO_2 pipelines within a state does not automatically guarantee the capacity to accommodate all the emissions from the power plants operating within that state. Additionally, similar to the natural gas pipeline projects discussed in a previous section of this report, FERC pipeline approval timelines have increased substantially over the last decade, raising the question if sufficient CO_2 pipeline projects can be approved in time for EPA's proposed Jan 1, 2030, compliance deadline.

The EPA's findings reveal that 37 states possess geological reserves suitable for CO_2 storage, while 30 states will have coal-based EGUs that would necessitate pipelines for the transportation of produced CO_2. This implies a significant shortfall in pipeline infrastructure to meet the demand.

Under the Underground Injection Control (UIC) program, the EPA has enacted regulatory guidelines and established federal requirements governing six classes of injection wells, ranging from Class I to Class VI, based on the nature and depth of injection activities. Class II wells are specifically designated for the injection of fluids associated with oil and natural gas production, serving purposes such as disposal, EOR, or hydrocarbon storage[44]. While both Class II and Class VI wells facilitate the underground injection of CO_2, they serve distinct objectives and are subject to disparate regulatory frameworks. Approximately 80 percent of active Class II wells are dedicated to Enhanced Oil Recovery, wherein CO_2 and other fluids are injected into oil-bearing formations to extract residual oil and natural gas. However, it is noteworthy that only Class VI wells are specifically designed for long-term CO_2 storage[45].

To safeguard underground sources of water and ensure the appropriate construction, testing, monitoring, and closure of wells utilized for CO_2 sequestration, the EPA has finalized requirements pertaining to this rule. Currently, there are only two active Class VI projects in the United States, both situated at Archer Daniels Midland's ethanol plant in Illinois[46]. One of these projects has completed its post-injection phase, with a total injection limit of 1 million metric tons, while the other project is in the injection phase, with a maximum total allowed injection of 6 million metric tons and a maximum allowed injection rate of 1.2 million metric tons. The permitting process for these projects typically spans around three years from application submission to issuance, but it can extend up to six years in general. Moreover, there are 111 Class VI applications that remain pending at present. Assuming all coal-fired steam EGUs likely to be affected by EPA's proposed GHG rule will choose to capture, transport, and store their CO_2 emissions, another 123 injection applications will be required to be processed and approved by the EPA in three years or less to ensure plants can meet the proposed Jan. 1, 20230, compliance deadline.

Long-term CO_2 Storage

The EPA acknowledges the technical feasibility and active implementation of geologic sequestration, which involves storing CO_2 in geologic formations. The National Energy Technology Laboratory (NETL) and the United States Geological Survey (USGS) have assessed the availability of geologic sequestration capacity and identified suitable locations for CO_2 storage. Accordingly, the EPA established that 43 states have onshore/offshore geographic availability or access via

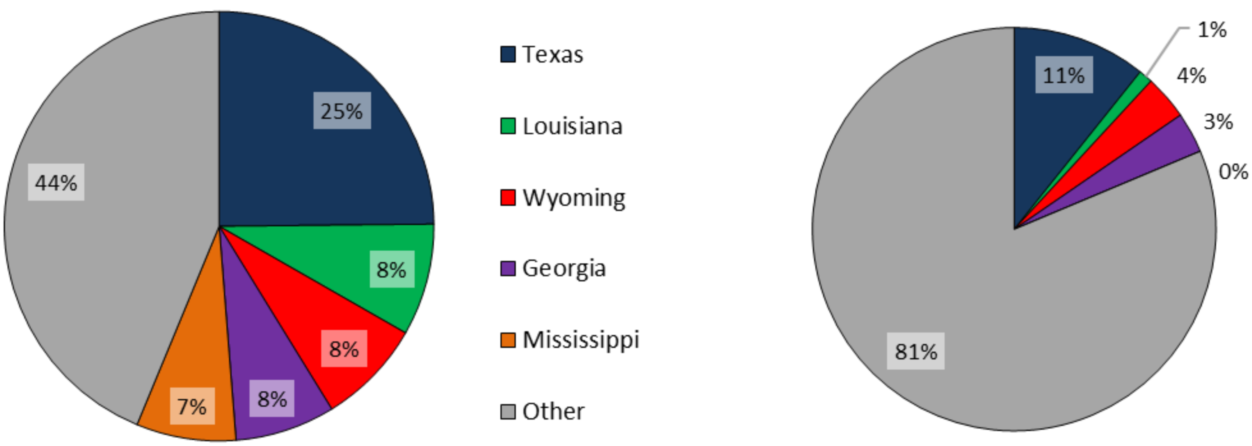
[43] CO2 Pipeline infrastructure – lessons learnt -https://doi.org/10.1016/j.egypro.2014.11.271
[44] https://www.epa.gov/uic/class-ii-oil-and-gas-related-injection-wells
[45] https://www.epa.gov/uic/class-vi-wells-used-geologic-sequestration-carbon-dioxide
[46] https://www.epa.gov/uic/class-vi-wells-permitted-epa#information

pipeline for geologic CO_2 sequestration potential[47]. Here, the EPA has defined 100 km (62 miles) as a reference number for the distance between CO_2 pipelines and the location with sequestration potential. Seven states, namely Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont, and Hawaii, do not have geologic sequestration potential or are not within 100 km of areas with potential.

The DOE's assessment focuses on physical constraints for CO_2 sequestration and estimates that areas in the United States with appropriate geology have a potential for storing between 2,400 billion and 21,000 billion tonnes of CO_2. This includes deep saline formations, oil and gas reservoirs, and unmineable coal seams. On the other hand, the USGS estimates a mean potential of 3,000 billion tonnes of technically accessible subsurface CO_2 sequestration across the United States[48].

In order to adopt a conservative approach, we utilized the low estimates for our subsequent analysis, thereby expanding the confidence interval pertaining to the actual presence of the specified reserve quantities. **EXHIBIT *27*** visually depicts that approximately 56% of the total reserve is concentrated within the top five states. In contrast, these states contribute merely 19% to the overall capacity share of coal-fired EGUs that are projected to continue their operation beyond the year 2031.

EXHIBIT 27: CO_2 STORAGE ESTIMATE (NETL LOW - LEFT) VS. PLANNED COAL CAPACITY IN 2030 (RIGHT) BY STATE

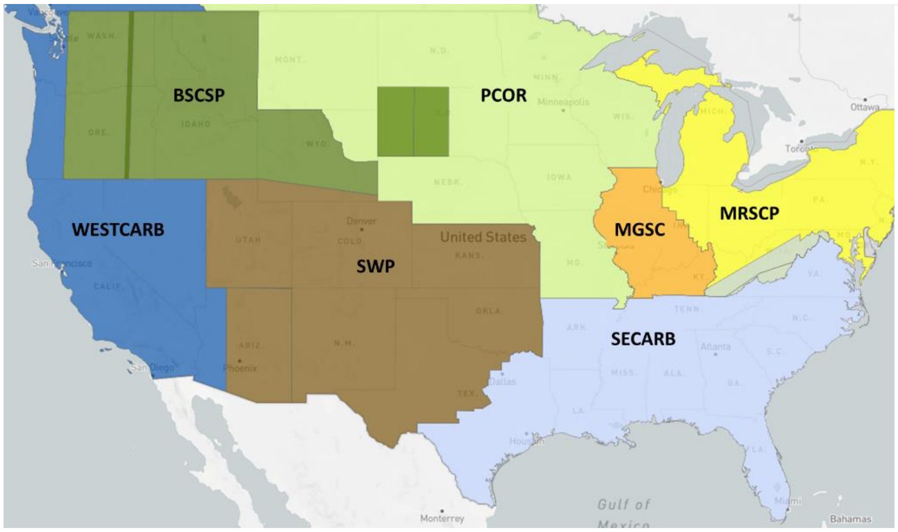


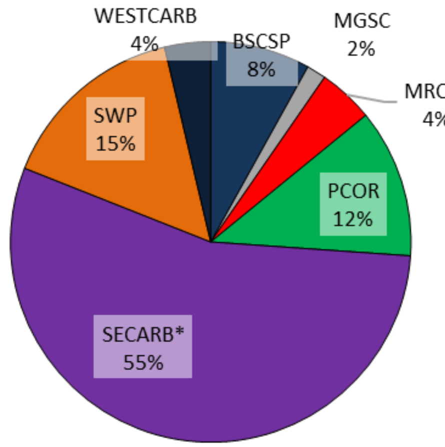
Source: NETL CO2 Storage Assessment + EVA Power Plant Tracking System

In 2014, NETL conducted a comprehensive analysis of possible long-term CO_2 storage by regional consortiums for different types of CO_2 storage formations. **EXHIBIT *28*** highlights the different regions included in NETL's 2014 report and their corresponding estimated CO_2 storage capability.

[47] https://www.federalregister.gov/d/2023-10141/p-930
[48] https://www.federalregister.gov/d/2023-10141/p-912

EXHIBIT 28: NETL NATCARB ATLAS REGIONS & ESTIMATE CO2 STORAGE CAPACITY DISTRIBUTION

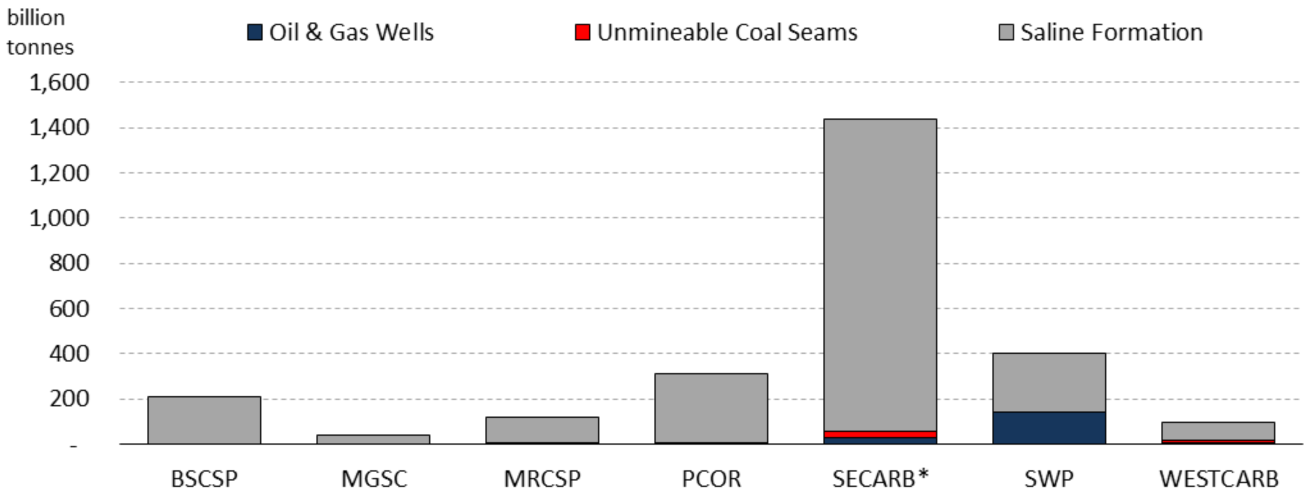




Source: NETL NATCARB Atlas; *SECARB includes ~500 bt of offshore federal saline storage

According to NETL's 2014 report, the Southeast Regional Carbon Sequestration Partnership (SECARB) accounts for more than half of the estimated CO_2 storage capacity. Notably, the region also includes about 500 billion tonnes (34%) of storage capacity located offshore in federal waters and is, therefore, not under state control or jurisdiction.

EXHIBIT 29: NETL ESTIMATED CO_2 STORAGE BY REGION & TYPE OF FORMATION

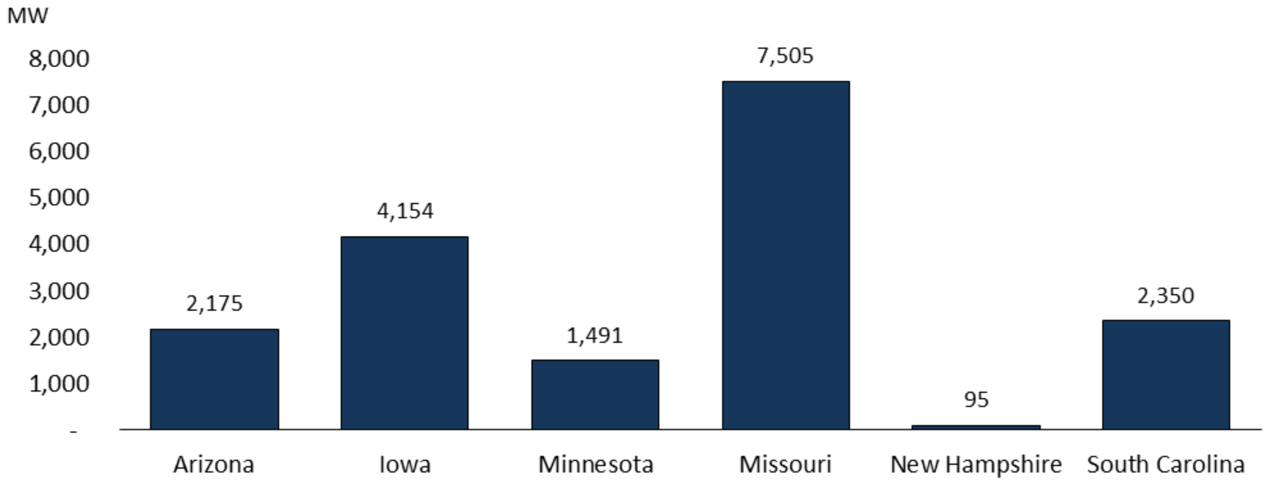


Source: NETL NATCARB Atlas; *SECARB includes ~500 bt of offshore federal saline storage

EXHIBIT *29* shows the difference in CO_2 storage formation by region assessed in NETL's CO_2 storage report. As mentioned above, SECARB account for roughly 55% of total estimated CO_2 storage, with over 95% of storage contributed to saline formations. Overall, saline formations account for over 90% of NETL's CO_2 storage estimate, while abandoned oil and gas wells and unmineable coal seams account for 7% and 2% of the total, respectively.

Further analyzing NETL's CO_2 storage estimates by state shows the regional discrepancy of the estimated storage volume. As mentioned previously, only five states account for more than 55% of the estimated CO_2 storage total, yet only account for 19% of the estimated coal capacity affected by EPA's proposed GHG rule. Additionally, six U.S. states, collectively accounting for 17.7 GW of coal-fired steam EGU capacity in 2030, do not have geological reserves. The six states are shown in **EXHIBIT *30***. **APPENDIX *3*** provides an overview of NETL's CO_2 storage estimate by state.

EXHIBIT 30: STATES WITH COAL CAPACITY BUT NO GEOLOGICAL CO_2 STORAGE



Source: USGS CO2 Storage Assessment + EVA Power Plant Tracking System

In summary, although individual parts of the Carbon Capture and Sequestration industrial complex have been proven, there currently does not exist any infrastructure project comparable to the size and magnitude required to capture and store long-term the amount of CO_2 from the projected 107.6 GW of coal-fired steam EGU capacity likely affected by EPA's GHG rule proposal. Basing emission standards or emission reduction guidelines on a technology and industry that does not yet exist at the scale needed to qualify as a nationwide applicable and implementable Best System of Emission Reduction is simply incorrect.

Appendix

APPENDIX 1: CAPACITY MIX BY EPA SCENARIO (GW)

	2022	2030		2040		2050	
	Actual	post-IRA	GHG	post-IRA	GHG	post-IRA	GHG
Coal	218	73	59	38	11	12	0
Natural Gas	545	513	527	556	587	734	745
Nuclear	100	92	92	79	79	45	45
Hydro	101	104	104	110	110	110	110
Wind	138	245	251	568	566	805	808
Solar	66	164	165	407	402	603	599
Energy Storage	7	69	69	128	124	161	160
Other	31	12	12	12	12	12	12
Total	**1,206**	**1,270**	**1,279**	**1,898**	**1,891**	**2,482**	**2,479**

APPENDIX 2: GENERATION MIX BY EPA SCENARIO ('000 GWH)

	2022	2030		2040		2050	
	Actual	post-IRA	GHG	post-IRA	GHG	post-IRA	GHG
Coal	829	354	197	99	75	16	2
Natural Gas	1,594	1,718	1,835	819	858	598	608
Nuclear	772	734	734	603	605	315	311
Hydro	253	302	306	348	347	348	348
Wind	434	874	903	2,145	2,134	3,022	3,035
Solar	144	394	397	999	982	1,484	1,470
Energy Storage	(1)	98	99	225	214	309	305
Other	51	66	67	63	63	58	58
Total	**4,075**	**4,540**	**4,536**	**5,301**	**5,277**	**6,149**	**6,138**

APPENDIX 3: NETL CO_2 STORAGE ESTIMATES & ESTIMATED COAL CAPACITY IN 2032 BY STATE

State	Low (billion tonnes)	High (billion tonnes)	Coal Capacity (MW)
Alabama	122	649	2,770
Alaska	9	20	-
Arizona	0	1	2,175
Arkansas	6	64	1,817
California	34	424	-
Colorado	35	357	-
Connecticut	-	-	-
Delaware	0	0	-
Florida	103	555	3,322
Georgia	145	159	3,504
Hawaii	-	-	-
Idaho	0	0	-
Illinois	21	216	3,496
Indiana	38	129	4,141
Iowa	-	0	4,154
Kansas	11	86	3,458
Kentucky	16	114	7,599
Louisiana	163	2,102	1,207
Maine	-	-	-
Maryland	2	2	-
Massachusetts	-	-	-
Michigan	32	67	1,531
Minnesota	-	-	1,460
Mississippi	145	1,185	-
Missouri	0	0	7,505
Montana	99	858	1,587
Nebraska	24	112	3,420
Nevada	-	-	-
New Hampshire	-	-	95
New Jersey	-	-	-
New Mexico	43	359	-
New York	4	5	-
North Carolina	1	18	7,241
North Dakota	73	237	3,827
Ohio	11	12	4,364
Oklahoma	23	212	2,795
Oregon	7	94	-
Pennsylvania	18	20	1,201
Rhode Island	-	-	-
South Carolina	30	34	2,350
South Dakota	4	12	474
Tennessee	1	5	-
Texas	479	4,373	11,552
Utah	24	242	2,270
Vermont	-	-	-
Virginia	0	3	610
Washington	37	497	-
West Virginia	17	30	11,220
Wisconsin	-	-	2,592
Wyoming	153	1,548	3,830

Technical Comments on the

Carbon Capture Utilization and Sequestration aspects of the proposed

New Source Performance Standards for GHG Emissions from New and Reconstructed EGUs; Emission Guidelines for GHG Emissions from Existing EGUs; and Repeal of the Affordable Clean Energy Rule

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August 7, 2023

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1 Summary

The U.S. Environmental Protection Agency (EPA) on May 23, 2023 proposed five separate actions under Section 111 of the Clean Air Act addressing greenhouse gas emissions (GHG) from fossil fuel power plants generating electrical power. EPA bases the proposed GHG rule on many unverified assumptions, but the most egregious is that carbon capture utilization and storage (CCUS) is a demonstrated technology and qualifies as best system of emission reduction (BSER). EPA (improperly) designates CCUS as BSER, then extrapolates CCUS cost metrics to a wide variety of generating units. That EPA uses questionable means to generalize CCUS cost is of concern, but such concern is secondary to the unsubstantiated claim – and flaw in EPA's proposal - that CCUS is BSER. Consequently, all CCUS-related cost and performance predictions fail.

This critical observation, supplemented with several others, is further described as follows:

The CCUS Utility experience base is inadequate.

There is a single CCUS process operating in North America relevant to utility power generation - Sask Power Boundary Dam Unit 3. This unit has operated since 2014, and over eight years of refinement exhibits increased reliability – which although improved can still be compromised by failure of specialty, hard-to-acquire components that cannot be readily "spared" on-site.

A second CCUS operating unit relevant to utility power application – the Petra Nova "slipstream" project at the W.A. Parish station - operated for 3 years before termination in March of 2020. As further discussed in Section 3, both demonstrations were significantly co-funded by federal (and for Sask Power Boundary Dam) the local (provincial) governments.

This collective large-scale CCUS experience – comprised of two units with one operating for an abbreviated period – does not reflect the variety of conditions for CCUS application to the U.S. generating fleet. Of particular note is that small-scale pilot plant tests for two proposed demonstrations – conducted in 2015 (Minnkota Power Milton R. Young) and presently ongoing (Basin Electric Dry Fork) and are necessary to address remaining risk. The lean CCUS experience is in sharp contrast to real-world lessons accumulated in the early- and mid-70s with first-generation flue gas desulfurization (FGD) technology, in which 20 generating units were equipped with FGD and operated (some for five years) prior to a federal mandate to limit sulfur dioxide (SO_2) emissions.

Industrial CCUS applications are inadequate to reflect utility power generation.

EPA cites numerous industrial applications that due to scale, effluent gas treated, atypical CO_2 content and process conditions, limited removal of CO_2, or intermittent operation, are of peripheral import to coal-fired utility application. Consequently, experience with industrial applications has no impact on qualifying CCUS as utility-scale BSER

Engineering "FEED" studies – regardless of the detail – do not deliver real-world operating experience and are not a substitute for "lessons learned" from authentic operation.

EPA, lacking relevant CCUS experience, cites up to 15 engineering (Front-End Engineering Design, or FEED) studies as a basis for BSER. EPA's premise is invalid for two reasons. First, FEED studies do not address "final" design – the latter exercise a separate step, prior to equipment procurement. Second, and more important, FEED studies are exclusively paper and digital exercises that do not include the critical follow-through of building, operating, and documenting experience that almost without exception leads to revised design.

This view is shared by two contractors that supported EPA in this rulemaking. Sargent & Lundy Engineers (S&L) and Bechtel National Corporation state CCUS FEED studies leave risks that are not addressed. Specifically, EPA sponsored S&L to develop model CCUS cost calculations referenced in the Technical Support Documents, which state CCUS is an evolving technology. Bechtel, prime contractor for the FEED study addressing CCUS retrofit to the Panda/Sherman natural gas/combined cycle (NGCC) generating unit, state the present level of CCUS experience is inadequate; they recommend – prior to full-sale application at Panda/Sherman - a large capacity pilot plant test be conducted.

The CCUS cost basis – both capital requirement and the levelized cost per ton ($/ton) to avoid CO2 - is highly uncertain and will remain so without additional large-scale demonstrations.

EPA attempts to compensate for the lack of experience by featuring paper and digital calculations, derived from unverified FEED studies, to determine the cost to avoid CO_2 ($/tonne).[1]

First, EPA – although citing FEED studies as a basis for BSER – ignore them as a source of capital cost for actual sites. Alternatively, EPA uses capital costs for a hypothetical unit, as determined by the National Energy Technology Laboratory (NETL) of the Department of Energy (DOE). A more authentic cost would be derived from the "average" of the six FEED studies – that even with uncertainty is "grounded" by actual site specifics. The difference in cost is not small - EPA's selected hypothetical unit capital cost is approximately 30% less than the average of the six FEED studies.

Second, EPA, when seeking estimates of cost to avoid CO_2 ($/ton basis), changes course and features the FEED studies ignored for capital cost. EPA highlights FEED study results - along with several from international studies – to showcase that cost to avoid a tonne of CO_2 ($/tonne) cluster near the research and development (R&D) target of $40/tonne. As previously described, FEED results are paper and digital exercises, describing facilities never built or tested. Further, key factors that drive the levelized cost result – capacity factor and remaining unit lifetime - are not presented. EPA's reporting of these costs is not transparent.

In summary – CCUS costs remain highly uncertain.

[1] All references to avoided cost are cited in terms of cost per metric tons ($/tonne).

EPA's projected schedule for CCUS deployment – from concept evaluation to injection of CO_2 for sequestration or enhanced oil recovery - is unrealistic and compressed even compared to optimistic projects.

EPA ignores schedules to retrofit CCUS issued by two sources: the contractor S&L whom they engaged for this purpose, and the Global CCS Institute. S&L developed for EPA a CCUS retrofit schedule describing 6.25-7 years as necessary and concede this applies to a partial scope of duties by ignoring CO_2 transportation (e.g. pipeline construction and permitting) and terrestrial sequestration (e.g. site development and permitting). The Global CCS Institute cites almost 9 years as necessary, but "pass" on realistic permitting challenges – by noting their schedule assumes "…. there is no significant community opposition" to the project. Experience in the U.S. particularly the Midwest – belies this assumption.

EPA assumes the responsibility of completing the schedule. EPA adds activities to S&L's scope but compresses the schedule by about 2 years. The resulting 5-year schedule – slightly more than half of the 8.25 years advised by the Global CCS Institute - allocates one half-year to for CO_2 "transport and storage" feasibility and two years for CO_2 sequestration "site characterization and permitting." These estimates are contrary to plentiful evidence such timeframes are not credible. Section 5 describes how acquiring a CO_2 pipeline permit – such as the proposed Navigator project in Iowa - appears to require 3.5 years and only if no other roadblocks emerge prior to end-of-year 2024. Section 6 summarizes detailed schedules developed for the FEED studies and show under ideal conditions – a "head-start" for sequestration site development and no barriers to CO2 pipelines - 8 years are required. Some projects will require possibly 12 years.

These studies suggest the 5-year time frame is unrealistic, with 10 years or more required for many projects.

CCUS does not qualify as BSER

EPA is to select BSER after considering if a technology is "adequately demonstrated", "commercially available," and can be deployed for a cost that is "reasonable", all while representing the best balance of economic, environmental, and energy considerations. Two utility demonstrations – both with significant government cofunding – do not comprise an adequate demonstration. Process equipment for CCUS can be purchased - but without meaningful guarantees from process supplier, the technology is not fully commercially available. Costs, projected mostly from paper and digital FEED studies, are highly uncertain.

CCUS is distinguished from all precedent environmental controls in that a significant fraction of power produced that would be directed to the grid – 20-30% for coal– is consumed by the process. This collection of conditions does not qualify CCUS as BSER in the present state of development.

2 INTRODUCTION

The U.S. Environmental Protection Agency (EPA) on May 23, 2023 proposed five separate actions under Section 111 of the Clean Air Act addressing greenhouse gas emissions (GHG) from fossil fuel power plants generating electrical power. New Source Performance Standards (NSPS) for stationary combustion turbines and coal-fired generating units to limit emissions of CO_2 are proposed, as well such limits for existing fossil fuel generating units fired by coal, or gas turbines operating in simple or combined cycle duty.

Of the elements of EPA's proposed regulation, there is one critical premise - the role EPA assigns to carbon capture utilization and storage (CCUS). EPA submits that CCUS – in the present state-of-art technology - is commercially proven and feasible for utility application to both coal-fired and natural gas combined cycle (NGCC) generating units. EPA projects via its Integrated Planning Model (IPM) that 39 coal-fired power plants – totaling almost 14 gigawatts (GW) of capacity – will adopt CCUS by 2030.[2] The premise of EPA's modeling results in arbitrarily determining that CCUS is the best system of emissions reduction (BSER).

This report addresses the technology status of CCUS in terms of designation as BSER. The operating experience to underpin future applications of CCUS technology is reviewed, considering commercial-scale duty, laboratory tests, and the paper or digital design studies funded by the National Energy Technology Laboratory (NETL) and others.

This report is comprised of 7 sections and an Appendix. Section 3 addresses the shortcomings with industrial experience and Front-End Engineering and Design (FEED) studies, the features of emerging technology, and the limited experience with two units equipped with CCUS. Section 4 reviews EPA's evaluation of CCUS cost, addressing capital required and the levelized cost to avoid CO_2 on a dollar per metric tonne basis ($/tonne basis), including the impact of tax benefits accrued through the Inflation Reduction Act (IRA). Section 5 highlights one aspect of CCUS EPA does not address in detail – the task of securing CO_2 pipelines for delivery to sites for sequestration or use for enhanced oil recovery (EOR). Section 6 addresses EPA's assumption that a five-year deployment schedule is realistic. Section 7 projects on a continental map of North America the locations of EPA projected CCUS applications, showing the relationship to existing and proposed CO_2 pipeline routing and potential geological sequestration or EOR sites. Select backup material is presented in Appendix A.

[2] U.S. EPA, *Integrated Proposal Modeling and Updated Baseline Analysis, Memo to the Docket* (EPA_HQ_OAR_2023_0072), July 7, 2023. Hereafter EPA 2023 Integrated Baseline Analysis.

3 CCUS EXPERIENCE RELEVANT TO BSER

The EPA has designated CCUS as BSER based on the following rationale:

The technology has been studied, examined, and tested for decades and it has reached a point in its development where it is adequately demonstrated and commercially available.[3]

The additional economic incentives are important for establishing that the cost of CCS is reasonable, and an appropriate BSER.[4]

Section 3 reviews the technical basis of CCUS, focusing on relevant utility power generation experience, considering the definition of technology as adequately demonstrated and commercially available, and the incurred cost.

It should be noted EPA does not propose criteria by which to gauge CCUS in terms of the metrics "adequately demonstrated", "commercially available", and a cost that is "reasonable", and "appropriate." Nor does EPA address the decision to select a technology with the "best" balance of economic, environmental, and energy considerations.

3.1 Criteria for "Adequately Demonstrated"

A technology is considered "demonstrated" when there is (a) adequate experience that reflects projected operating duty, (b) confidence that operation is reliable over extended periods of time, and (c) the technology suppliers can *offer meaningful guarantees,* more than equipment and engineering services for sale. EPA in several instances distorts the meaning of the term "demonstrated". Most notable are (a) application at industrial or small-scale processes, and (b) the significance of engineering studies, the latter without corroborating results. These are described as follows:

3.1.1 Industrial Applications

EPA submit that industrial application of CCUS – particularly for cases that "report" 90% CO_2 capture – contribute to demonstrating CCUS for utility applications.

Industrial applications significantly differ from utility-scale power generation. Utility applications are distinguished by continual 24 x 7 duty, operation at high reliability, and processing flue gas with CO_2 content that differs from utility power generation – the latter typically 3-4% CO_2 for NGCC application and 11-13% CO_2 content for coal-fired application. Almost all non-utility applications treat product gases with higher CO_2 concentrations – such as

[3] Greenhouse Gas Mitigation Measures for Steam Generating Units – Technical Support Document. Docket EPA-HQ-OAR-2023-0072. Page 35. Hereafter Steam EGU TSD.
[4] Ibid.

chemical and ethanol production, and processing of hydrogen and ammonia, by up to a factor of 10. These high concentrations of CO_2 elevate the "driving force" for mass transfer and adsorption, which combined with a smaller scale and shorter physical distance over which to effect mixing and CO_2 absorption present different challenges than for power generation.

EPA's industrial "reference applications" are not relevant to utility duty. Specifically, EPA claims CCUS viability is "*.... further corroborated by CO2 capture projects assisted by grants, loan guarantees, and Federal tax credits for "clean coal technology" authorized by the EPAct05. 80 FR 64541–42 (October 23, 2015).*"[5] EPA cite a compilation of 72 CCUS projects – demonstration tests, pilot plant test, CO_2 storage, and transport activities - as relevant supporting their assessment, per Excel file "Attachment_1",[6] of which only two treat the entirety of gas flow generated. These two facilities – the Searles Valley Minerals caustic soda plant and the Quest methane reformer – do not represent large-scale utility duty, nor is there evidence that CO_2 removal matched that proposed by EPA for 24x7 duty. Other sites referenced by EPA are the "slip stream" category of process testing for which CCUS reliability does not limit that of the host unit.[7] Two "slip-steam" tests cited in the "Attachment 1" reference file are discussed subsequently - the Bellingham Energy Center for NGCC duty and the Petra Nova demonstration (discussed in Section 3.3).

The sites reported to process the entirety of product gas - Searles Valley Mineral and Quest - are further described as follows:

<u>Searles Valley Minerals.</u> Public information suggests CO_2 capture is either intermittent or derives CO_2 removal well below 90%. The Searles site is comprised of three coal-fired units – two generating 27.5 MW and a third at 7.5 MW.[8] The CO_2 removal capability is cited as 800 tons per day[9] which suggests relaxed duty. Specifically, if the CO_2 removal process treats flue gas from the smallest (7.5 MW) capacity unit, operation at 80% capacity factor will generate 2,375 tons of CO_2 per day – and daily CO_2 removal of 800 tons implies either a 33% removal for a complete 24-hour day, or 90% CO_2 removal for 35% operating time (perhaps one "daytime" shift). These performance metrics are not adequate to qualify CCUS as demonstrated technology.

<u>Quest.</u> The effluent from this methane reforming process does not reflect combustion products, as CO_2 content is elevated compared to utility application. Experience with CO_2 removal at

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[5] Steam EGU TSD. Page 22.

[6] EPA-HQ-OAR-2023-0072-0061_attachment_1.

[7] Three additional facilities are listed as operating CO2 capture, but as a "slipstream'. (AES Warrior Run, AES Shady Point, and Bellingham Energy Center). The slipstream process arrangement – a useful means for research and development - does not link the reliability of the host process to the CO_2 capture technology – and thus cannot represent conditions for 24x7 utility power generation demonstration.

[8] Energy Information Agency 860 Data, File 3_1_Generator_Y2021. Operable tab, Rows 9148-9150.

[9] Elmoudir, W. et. al., *HTC Solvent Reclaimer system at Searles Valley Minerals Facility in Trona, CA*, Energy Procedia 63 (2): 6156-6165, December 2014.

highly elevated content – although contributing to general CCUS knowledge – is not a basis to designate CCUS as BSER for utility application.

Bellingham Energy Center. This NGCC unit is host to a 40 MW slip-stream employing a first-generation amine-based process (that evolved as the Flour Econoamine process). There is no data available to describe these results - a DOE "fact sheet" reports the unit operated from 1991 through 2005, with CO_2 removal of "85-95%".[10] It is not known if operation was continual versus intermittent, pending market demand for commercial grade CO_2. If periods of 85-95% CO_2 removal are interspersed with lower targets, this experience does not support BSER for utility application.

In summary, experience with industrial CCUS applications, although contributing to CCUS technology evolution, does not qualify CCUS as demonstrated for utility duty.

3.1.2 Engineering FEED Studies

EPA claims studies of CCS feasibility for utility duty – "Front End Engineering Design" or FEED studies – contribute to designating the technology as "demonstrated".

Three phases of analysis are typically employed to develop a CO_2 capture design. The first step defines the overall features of the design, using general site information, and "budgetary" cost quotations. This "pre-FEED" study presents a feasibility "yes/no" test.

The second step - the FEED study – is intended to (a) develop in more detail process flowsheets and/or equipment arrangement drawings, and (b) solicit budgetary quotations from suppliers to establish cost and availability. Some FEED studies include a construction plan, addressing the fabrication and delivery of the largest components to the site. At present, there are 13 such FEED studies (listed in Section 5) addressing coal-fired and NGCC generators that are complete.

The third phase is detailed engineering which specifies equipment physical attributes, layout, and an operating plan in detail to develop a request for proposal and solicit a supplier "firm" designs and cost. This detailed engineering step has been completed only for the Sask Power Boundary Dam 3 and the Petra Nova projects. For developed technology, this third phase should solicit from suppliers a performance and/or reliability guarantee from equipment suppliers.

EPA cite four FEED studies for coal and three for NGCC,[11] with seven more planned.[12] EPA rightfully identifies these FEED studies as "…projects in the early stages of assessing the merits

[10] U.S. Department of Energy (DOE). Carbon Capture Opportunities for Natural Gas Fired Power Systems. Available at https://www.energy.gov/fecm/articles/carbon-capture-opportunities-natural-gas-fired-power-systems.
[11] Steam EGU TSD. P. 23.
[12] EPA-HQ-OAR-2023-0072-0061_attachment_1.

of retrofitting coal steam EGUs with CCS technology", with potential for "…the application of CCS to existing gas facilities".[13]

As will be shown for several projects, there remain significant "post-FEED" details in design and specifications for procurement. Most importantly, FEED studies as paper and digital exercises are absent the critically important "learning by doing" – the frequently quoted guidance from the Global CCS Institute as necessary to evolve CCUS.[14]

Four FEED studies are cited in the Steam EGU TSD for coal-fired duty: Basin Electric Dry Fork, Prairie State Generating Station, the Milton R. Young Station of Minnkota Power, and Nebraska Public Power District's Gerald Gentleman Station. Each of these studies is complete and project CCUS capital cost, and with assumptions of unit lifetime and capacity factor projecting an implied cost to avoid CO_2 ($/tonne). Capital cost results from these projects – in addition to analogous studies addressing Enchant Energy San Juan and Sask Power's Shand station – are addressed in Section 4.

Four newly launched studies have not progressed to delivering cost estimates. These are Cleco Brame Energy Center Madison Unit 3 (pet coke/bit coal) (Lena, LA); Duke Energy's Edwardsport integrated gasification combined cycle (IGCC) facility (Edwardsport, IN); Four Corners Station (located on the Navajo Nation in AZ); and CWL&P Dallman Unit 4 (Springfield, IL).

FEED studies are important but on their own are inadequate to qualify a technology as commercial. In at least two instances, FEED study authors advised additional pilot plant testing.

<u>Basin Electric Dry Fork Coal-Fired</u>. A 2020 FEED study by S&L evaluated MTR's membrane CO_2 capture technology for application to the Basin Electric Dry Fork station, and had advised the next phase of activities a 10 MW "large" pilot plant test,[15] evolving to a "slip stream" configuration for "partial capture conditions" at 400 MW capacity. This advisement offered in 2020 is testament to the evolving nature of CCUS technology.

<u>NGCC Combined Cycle</u>. A FEED study conducted by Bechtel National examined retrofit of a generic monoethanolamine (MEA) process to the 758 MW Panda Sherman Power Project. The principal investigators noted: *"At the time of this FEED study, no full-scale NGCC power plants with PCC was built anywhere in the world; even pilot studies using NGCC flue gas conditions were limited. This leads to a lack of data for process simulation model validation under conditions of interest for commercial NGCC+PCC plants…."*.[16]

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[13] Steam EGU TSD. P. 23.

[14] Technology Readiness and Cost for CCS, Global CCS Institute, March 2021. Available at https://www.globalccsinstitute.com/resources/publications-reports-research/technology-readiness-and-costs-of-ccs/

[15] Freeman, B. et. al., Commercial-Scale FEED Study for MTR's Membrane CO2 Capture Process, presentation to the Carbon Capture Front End Engineering Design Studies and CarbonSafe 2020 Integrated Review Webinar, August 17-19, 2020. P. 23.

[16] Elliot, W.R. et. al., *Front-End Engineering Design (FEED) Study for a Carbon Capture Plant Retrofit to a Natural Gas-Fired Gas Turbine Combined Cycle Power Plant (2x2x1 Duct-Fired 758-MWe Facility*

The principal investigator then concludes: *"A pilot testing program is therefore proposed to resolve most of these design uncertainties, generally duplicating all process elements of the full-scale PCC unit apart from CO2 product compression."*[17]

This is S&L's second advisement that CCUS is emerging technology – in addition to recommending a pilot plant test at Dry Fork prior to commercial demonstration, S&L describe the technology as "emerging" in an explanatory note issued with the proposed CCUS schedule.[18]

FEED Studies are critical to project development for CCS as this technology is an emerging technology with very limited full-scale / commercial installations.

In summary, FEED studies develop the arrangement of process equipment and preliminary cost for CCUS. These conceptual exercises are inadequate to qualify CCUS as BSER.

3.2 Stages of Emerging Technology

Commercially available technologies are characterized by operating experience that enables process suppliers to provide meaningful performance guarantees.

As noted by S&L, CCS is considered an "emerging technology"[19] which typically evolve in several stages. Early projects are based on limited experience and the role of process suppliers evolves during this period. It must be emphasized there is stark contrast between a supplier offering "for sale" an engineered design and fabricated hardware, in contrast to providing meaningful process guarantees. This subsection further addresses these topics.

3.2.1 First, Nth-of-a-Kind

Any new process – or application of an evolving process to conditions outside present-day experience – is considered the "first" of a "kind" (FOAK). Such FOAK designs are characterized by uncertainty in terms of equipment arrangement, process conditions (reaction chemistry, flow field, temperature), and operating duty, and the risk to achieve environmental control performance and reliability.

FOAK designs can address risk and uncertainty but only by large-scale testing and operation for extended periods. Projects subsequent to FOAK are described as the "Nth-of-a-Kind" (NOAK), in which additional (the nth) application addresses evolving conditions. There is no clear delineation between the number of FOAK applications necessary to evolve to NOAK.

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with F Class Turbines), Final Scientific/Technical Report, DE-FE0031848, March, 2022. P. 2. Hereafter Panda Sherman 2022 Final Report.

[17] Ibid.

[18] S&L_CCS_Schedule_EPA-HQ-OAR-2023-0072-0061_attachment_16.pdf.

[19] Ibid.

Power industry technologies are not considered "demonstrated" until adequate "NOAK" applications operate for sufficient time, defining and resolving uncertainties. There is no broadly recognized threshold for the number of acceptable NOAK projects to be completed prior to commercial maturity. The DOE acknowledges this uncertainty with regard to CCUS, in noting NOAK designs can include equipment that "…. are not fully mature (e.g. plants with IGCC and any plant with CO_2 capture…", and will incur costs higher than reflected within their most recent analysis.[20]

That CCUS is a FOAK or NOAK is evidenced by actions at planned demonstrations at the Basin Electric Dry Fork and Minnkota Power Milton R. Young station. As described in Section 6, the site-specific process design for these sites relies heavily on pilot plant tests – either completed (in 2015) or presently underway – at the site. The uncertainties which remain are best addressed at pilot scale which is proof CCUS technology is not mature.

The uncertainty of FOAK designs is also recognized in the Princeton "Net-Zero" study.[21] The analysis suggests five FOAK designs must be built and operated for – in their opinion – sufficient time for costs to "settle"; but with broader implications for mitigating risk.

3.2.2 Commercially Available

EPA implies CCUS processes are commercially available when suppliers offer to sell the necessary process equipment and engineering services. However, a supplier offering to design, procure and install such hardware does not constitute commercial availability. The missing requirement is meaningful guarantees of process performance, backed with remedial action if goals for emissions removal or reliability are not attained.

Neither Sask Power or Petra Nova process hardware were reported as awarded performance guarantees. That absence of commercial guarantees is the reason both projects were significantly co-funded by federal and local governmental entities, with additional funds defraying risk inherent to a FOAK concept.

3.3 North American Utility Scale Processes

At present, there is one operating CCUS unit in North America from which to assess commercial feasibility – Sask Power Boundary Dam Unit 3. A second CCUS-equipped unit – Petra Nova – operated for 3 years (terminating in March 2020). Both of these demonstrations provide significant experience – but on their own do not establish CCUS as demonstrated and commercially available.

A brief summary of these two projects is presented in this subsection.

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[20] *Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity*, DOE/NETL – 2023/4320, October 14, 2022. P.50

[21] The Princeton Net-Zero Project - *Potential Pathways, Infrastructure, and Impacts.* Available at https://netzeroamerica.princeton.edu/?explorer=year&state=national&table=2020&limit=200

3.3.1 Sask Power Boundary Dam 3

Overview. Sask Power has operated CCUS at Boundary Dam Unit 3 since 2014, employing an early generation Cansolv CO_2 process. Inherent to the Cansolv process is a SO_2 removal step – controlling SO_2 to less than 10 parts per million (ppm) – that combined with improved particulate matter control protects the amine sorbent from degradation.

This activity was significantly cofunded by the Canadian and Saskatchewan provincial governments. The capital budget is approximately $1.2 B (USD), of which $240 M is provided by the Canadian and provincial government. The retrofit of CCUS was contemporaneous with refurbishing the steam turbine and the electric power generator to support 30-year operation.

CO_2 Disposition. CO_2 is compressed to 2,500 pounds per square inch gauge (psig) and transported 70 kilometers (km) by pipeline to the Weyburn oilfield for EOR, where it is injected 1.7 km underground. CO_2 not employed for EOR is transported 2 km for sequestration in the Deadwood saline aquifer (referred to as Aquistore).

As the Steam EGU TSD notes, a key issue is protecting the amine sorbent from decay with exposure to trace metals and SO_2. Several issues not unique to CCUS process equipment have compromised reliability. EPA note CCUS reliability was compromised in 2Q 2021 due to a failed CO_2 compressor, but dismiss this as not inherent to CCUS reliability. However, Sask Power cites these large, special purpose components as rare, and due to limited inventory are not immediately accessible. The cost to maintain "spares" on site is prohibitive. To assure high reliability, additional capital cost should be allocated to provide access to spare equipment; alternatively, enhanced operation and maintenance (O&M) should be planned and include downtime for "preventive" maintenance.

Observations are offered for Sask Power Boundary Dam 3 in three categories: reliability, cost of CO_2 capture ($/tonne), and implementation schedule.

Reliability. The availability of the Boundary Dam 3 CCUS facility is publicly reported in the Sask Power's CCUS Blog.[22] This latter source reports the reliability separately of the host boiler and CCUS process since Q1 2021. Figure 3-1 presents two quarterly reports that describe reliability continuously from Q1 2020 through Q1 2023 (available as of July 24, 2023). The top portion of each chart reports Boundary Dam Unit 3 availability (white background) and the lower portion of each chart reports CCS facility availability (gray background).

Considering CCS facility alone, Figure 3-1 shows the average of availability from Q2 2021 through Q1 2023 is 64.5% over this period. The loss of the compressor is a major contributor to this shortfall and a factor to be encountered in commercial duty.

[22] https://www.saskpower.com/about-us/our-company/blog/2023/bd3-status-update-q1-2023

Cost. As a FOAK retrofit, Boundary Dam 3 cost although not representative is informative. As previously described, capital cost (including plant refurbishment was \$1.2 B (U.S, 2014-dollar basis),[23] with the Canadian government contributing \$240 M.[24]

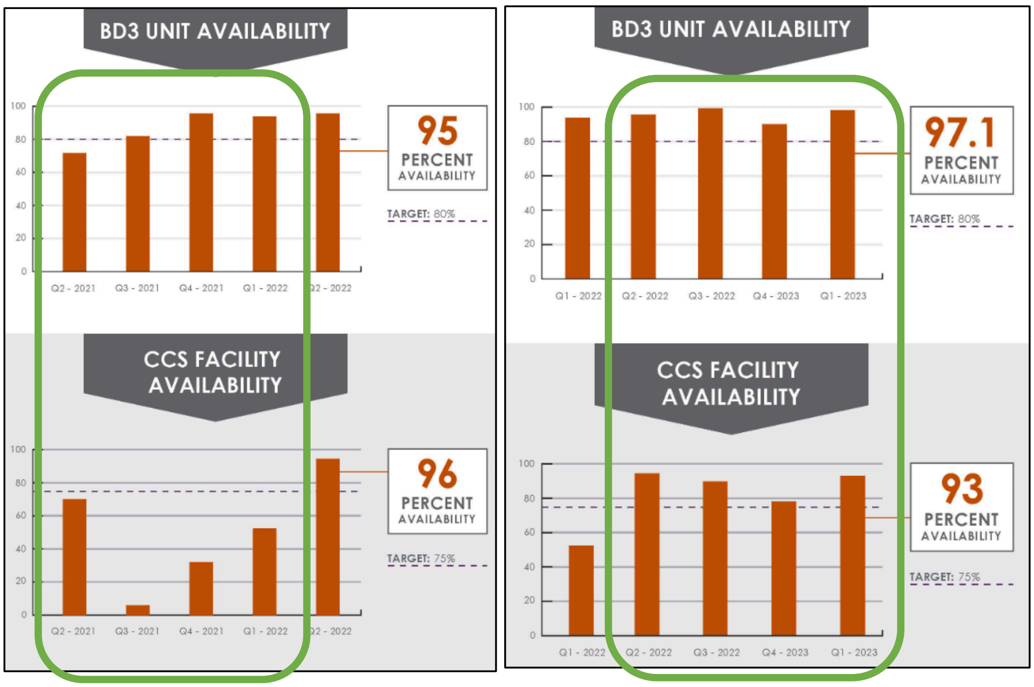

Figure 3-1. Reliability of Boundary Dam Unit 3, CCUS Process: Q1 2021 to Q1 2023

Sask Power report 50 percent of the cost is attributable to the CO_2 capture and regeneration process, 30 percent for power plant refurbishment, and 20 percent for other emissions control and other efficiency upgrades.[25] Consequently, \$600 M of capital is accounted for CCUS, equivalent to \$5,405/kW $_{\text{(net, w/CCUS)}}$.

The levelized cost to avoid one tonne of CO_2, as reported by the CCS Knowledge Center, is \$105. This cost estimate is based on a capacity factor of 85 percent, lifetime of 30 years, and a credit for CO_2 as EOR.[26] It should be noted CCUS availability since 1Q 2021 has prevented this cost of \$105/tonne from being achieved.

[23] https://financialpost.com/commodities/energy/jim-prentice-to-wind-down-carbon-capture-fund-in-alberta-new-projects-on-hold?. Canadian dollar values at 0.86 USD in 2014.

[24] See: https://www.powermag.com/saskpowers-boundary-dam-carbon-capture-project-wins-powers-highest-award/

[25] Giannaris et. al. 2021.

[26] *The Shand CCS Feasibility Study Public Report*, November 2018, CCS Knowledge Center. Available at https://ccsknowledge.com/initiatives/2nd-generation-ccs---Shand-study. Hereafter Shand 2018 Feasibility Report.

Schedule. Sask Power does not report schedule details from concept inception to delivering CO_2 for EOR, but reports the project took 6 yrs from "…commitment to completion".[27] Given the proximity to both an existing oil field (Weyburn) and saline reservoir (~10 mile) the actions to acquire permits - not reported by Sask Power - are likely atypical for most of the U.S. domestic fleet.

Sask Power's schedule may be relevant only for units situated in oil producing regions. Considering the cost subsidy, the reliability issues, and the incurred cost of CO_2 control, Boundary Dam 3 experience does not qualify CCUS as "adequately demonstrated" or "commercially available".

3.3.2 Petra Nova

Overview. NRG, owners of the W. A. Parish Generating Station, operated the Petra Nova CCUS process at Unit 3 from March 2017 through March 2020. This process employed the second-generation KM-CDR solvent developed by MHI and Kansai Electric Power Company, previously tested at 25 MW scale at Alabama Power Company's Barry Station.

The Petra Nova demonstration, significantly co-funded by the U.S. DOE, required capital of approximately $1 B. The CCUS process is not applied to the entirety of Unit 3 flue gas, but rather a 240 MW-equivalent slipstream, thus not affecting host unit reliability. Petra Nova's CCUS process hardware is unique – a 78 MW gas turbine (GE 7FA) was installed with a heat recovery steam generator (HRSG), the latter the source for CCUS auxiliary steam. The power generated by the gas turbine not consumed by the CCUS process (reported as 35 MW) is sold to the energy grid.[28]

CO_2 Disposition. CO_2 upon regeneration is compressed to 1,900 psig and transported 81 miles by pipeline for EOR at the West Ranch site, requiring injection between 5,000 feet to 6,000 feet underground. Unlike Boundary Dam Unit 3, there is no alternative means of CO_2 disposition.

Similar to Boundary Dam Unit 3, numerous operating issues were encountered with ancillary components. Heat exchangers processing reagent denoted as cool lean (without CO_2) and hot rich (with CO_2) were prone to leaks, while the gas quencher accumulated deposits that restricted performance. Some issues are attributed to penetration of SO_2 entering the capture process. These components are necessary for CCUS and their failure should not be dismissed as incidental. In the third operating year, additional factors such as tube corrosion in the solvent reclaimer were encountered that - similar to Sask Power – can compromise CO_2 compressor performance.

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[27] SaskPower's Boundary Dam Carbon Capture Project Wins Powers Highest Award, Power, https://www.powermag.com/saskpowers-boundary-dam-carbon-capture-project-wins-powers-highest-award/
[28] W.A. Parish Post-Combustion CO_2 Capture and Sequestration: Demonstration Project DOE Award Number DE-FE0003311 Final Scientific/Technical Report, Report DOE-PNPH-03311, March 31, 2020. Hereafter Petra Nova 2020 Final Report.

Observations are offered for the Petra Nova project in three categories: reliability, cost of CO_2 capture ($/tonne), and implementation schedule.

Reliability. CCUS reliability increased each year. Considering both the CO_2 capture system and the source of auxiliary steam, in the last operating year (2019) 49 days were fully or partially lost. Although an improvement from the 108 observed in 2017, the CCUS process was still not available for 13.4% of operating time in the third and best year.

Cost. Petra Nova report a $1B capital cost with approximately 60% expended for the CO_2 capture equipment, gas turbine, and the HRSG – the latter to provide auxiliary steam. The remaining approximately 40% of the cost was dedicated to administrative matters, the share of the CO_2 pipeline, and improvements to the oil field to enable higher CO_2 injection for EOR. Funding sources were a DOE grant of $190 M, financing of $250 M, and equity offered by the sponsors. One trade journal noted Petra Nova financing conditions were unique: "Like other early CCS demonstration projects, Petra Nova's financial viability relied on a rare alignment of incentives, including a DOE grant, cheap credit from Japan, and part-ownership of an oilfield, which probably has limited relevance for future CCS plans under the new fiscal policy."[29]

The project sponsors are not forthcoming with actual incurred cost per tonne ($/tonne). The final report to DOE[30] does not address this cost metric. The EPA in the Steam EGU TSD cite a cost of $65/tonne, as referenced to the Global CCS Institute,[31] who in turn cite a Petra Nova Technical Report from a period (July 2014 through December 2016) prior to unit operation.[32] Consequently, the $65/tonne is a pre-operational estimate, no different than a FEED evaluation, for which basic parameters of unit lifetime and capacity factor are not shared. Also, project economics should account for the incremental revenue derived from the 35 MW delivered by the gas turbine (acquired under the CCUS budget) to the grid. (This revenue could lower CCUS levelized cost, but no details are provided.)

Schedule. Petra Nova required a 6-year schedule for their activities, with work initiating in early 2011 to enable an air permit to be filed in September 2011,[33] although details are absent in the public schedule.[34] Petra Nova is unique as the Texas Gulf Coast provides an ideal location for CCUS given existing pipeline corridors and proximity of oilfields that can readily accept significant CO_2 injection.

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[29] https://www.nsenergybusiness.com/features/petra-nova-carbon-capture-project/#
[30] Petra Nova 2020 Final Report.
[31] Technology Readiness and Costs of CCS, March 2021, the Global CCS Institute. See page 35.
[32] W.A. Parish Post-Combustion CO2 Capture and Sequestration Project, Topical Report/Final Public Design Report, Award No. DE-FE0003311, for July 01, 2014 to December 31, 2016. See page 30.
[33] Ibid. P. 13.
[34] *Petra Nova Carbon Capture*, presented to the Carbon Capture, Utilization and Storage, and Oil and Gas Technologies Integrated Annual Review Meeting, August, 2019. Graphic 3. Available at: https://netl.doe.gov/sites/default/files/netl-file/Anthony-Petra-Nova-Pittsburgh-Final.pdf

The Petra Nova project schedule may be relevant only for units situated in oil producing locales. Considering the cost subsidy required, and complicated by reluctance to release the final costs, the Petra Nova project – although contributing to CCUS technology development - does not qualify CCUS as BSER.

4 REVIEW OF EPA's PROJECTION OF CCUS COST

4.1 Overview

Section 4 critiques EPA's cost evaluation of CCUS. As noted in Section 3, there are only two verified capital cost reports for CCUS –Sask Power Boundary Dam Unit 3 and Petra Nova. EPA's proposed trajectory of CCUS evolution more optimistic compared to that observed for flue gas desulfurization (FGD) technology, in which multiple demonstration tests (many <100 MW) operated for up to 5 years prior to federal legislation mandating FGD deployment. Further, EPA is inconsistent in their selection of references – after lauding FEED studies that EPA submits demonstrate the technology as commercial – EPA ignores these results when seeking capital cost. Finally, EPA does not consider the risk to reliability presented by CCUS, that compromises CO_2 removed and tax benefits accrued through the IRA.

These are further described as follows.

4.2 Inadequate Experience for Cost Basis

There is little verified experience with CCUS to base EPA's estimate of cost. In contrast, FGD evolved through approximately 20 commercial-scale processes that provided significant experience at utility conditions, prior to federal legislation mandating their use.

Figure 4-1 presents for FGD technology the installation date and flue gas equivalent generating capacity treated for installations through mid-1978. It should be noted that 20 FGD installations were installed and operating prior to the 1977 Clean Air Act Amendments - with at least 10 operating for up to 5 years.[35] This experience served as the basis to mandate the use of FGD.[36]

Figure 4-1 shows that – prior to 1977 and drafting of the Clean Air Act Amendments in that year – FGD technology evolved in a logical manner. The first 3 years (through 1975) saw 10 installations, of which all but three were of 150 MW of capacity or less. Notably, three installations that exceeded 400 MW in capacity were an early design variant – the "combined particulate/SO_2" process - which incurred either reliability or SO_2 removal challenges. These combined particulate/SO_2 processes – almost without exception – required refurbishment or replacement with "conventional" limestone FGD technology.

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[35] Shattuck, D. et. al., *A History of Flue Gas Desulfurization (FGD) – The Early Years*. Available at https://www.science.gov/topicpages/g/gas+desulphurization+fgd.

[36] Aldy, J. E. et. al., *Looking Back at Fifty Years of the Clean Air Act*, Resources for the Future Report 20-01 October 2020, Revised December 2020. Available at: https://media.rff.org/documents/WP_20-01_rev._Looking_Back_at_Fifty_Years_of_the_Clean_Air_Act_hmvW55y.pdf.

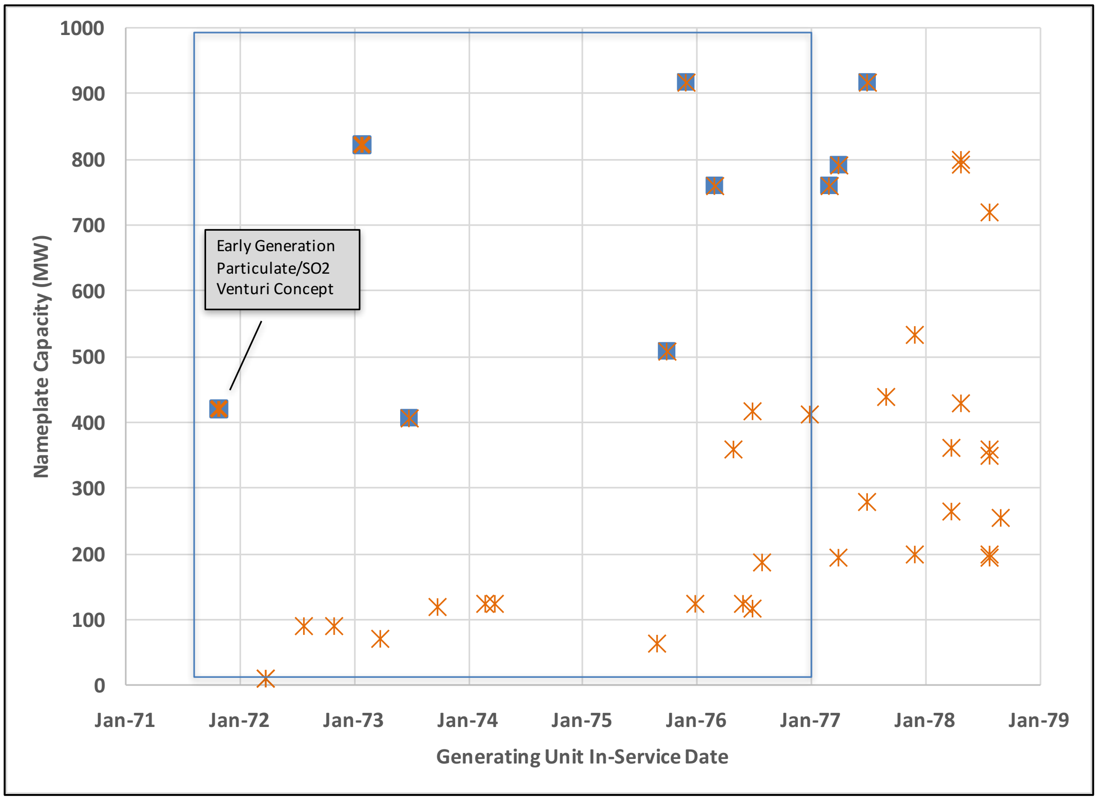

Figure 4-1. Evolution of Wet FGD Technology: The First Decade

In summary, compared to the status of FGD technology at the time of federal legislation mandating use, CCUS at present is characterized by inadequate experience, affecting cost and reliability. Consequently, CCUS experience is inadequate to base federal regulation for CO_2 removal at the scope and timescale as proposed.

4.3 FEED Study Capital Cost

EPA, after lauding FEED studies to justify CCUS as BSER, ignores FEED results when seeking a realistic capital cost for use in their analysis of avoided CO_2 cost ($/tonne). This section submits FEED studies that provide a better estimate of CCUS capital cost than EPA's use of a hypothetical "model" plant.

As described in Section 3, FEED studies are the second step of a three-phase process to develop engineering details for a CCUS design. Even with six FEED results "in-hand", EPA uses an S&L "model" to generate CCUS capital cost for a "hypothetical" unit, reporting results in Table 7 of the Steam EGU TSD. Of note are three S&L's disclaimers in the source document describing the limits in the use of the model to generate costs.[37] These address scope, site factors, and the lack of a cost "benchmark – as described as follows:

[37] IPM Model – Updates to Cost and Performance for APC Technologies: CO_2 Reduction Retrofit Cost Development Methodology, Final Report, Project 13527-002, March, 2023. Hereafter S&L 2023 CO_2 IPM.

Scope:

Transportation, storage, and monitoring (TS&M) of the captured CO_2 are not included in the base cost estimates and instead costs can be included as a user input on a $/ton basis.

Site Factors:

The IPM cost equations do not account for site-specific factors that can significantly affect costs, such as flue gas volume and temperature, and do not address regional labor productivity, local workforce characteristics, local unemployment and labor availability, project complexity, local climate, and working conditions.

Cost "Benchmark" or Validation:

Due to the limited availability of actual as-spent costs for CO_2 capture projects, the cost estimation tool could not be benchmarked against recently executed projects to confirm how accurately it reflects current market conditions.[38]

These disclaimers are clear – scope is not complete and terminates with CO_2 at the fence line; site factors are ignored; and results are not validated with experience. Consequently, cost estimates for CCUS capital and the levelized cost to avoid CO_2 ($/tonne) are at-risk. An alternative approach is to use FEED site specific results and adopt the average capital cost.

Figure 4-2 presents CCUS capital cost <u>*per net generating capacity after CCUS*</u> for the two demonstrations and the six FEED studies for coal-fired generating units. Capital cost is reported for Sask Power Boundary Dam 3,[39] Sask Power Shand,[40] Petra Nova,[41] Basin Electric Dry Fork,[42] Minnkota Milton R. Young,[43] Enchant Energy San Juan,[44] Nebraska Public Power

[38] S&L 2023 CO_2 IPM at p. 1.

[39] Coryn, Bruce, *CCS Business Cases*, International CCS Knowledge Center, Aug 16, 2019, Pittsburgh, PA.

[40] Giannaris, S. et. al., Implementing a second-generation CCS facility on a coal fired power station – results of a feasibility study to retrofit SaskPower's Shand power station with CCS, available at: https://ccsknowledge.com/pub/Publications/2020May_Implementing_2ndGenCCS_Feasibility_Study_Results_Retrofit_SaskPower_ShandPowerStation_CCS.pdf.

[41] Final Scientific/Technical Report, *W.A. Parish Post-Combustion CO_2 Capture and Sequestration Demonstration Project,* DOE Award Number DE-FE0003311, Petra Nova Parish Holdings LLC, March 31, 2020, Report DOE-PNPH-03311. Hereafter Petra Nova 2020 Final Report.

[42] Commercial-Scale Front-End Engineering Design Study for MTR's Membrane CO_2 Capture Process, Final Technical Report, November 10, 2022. Hereafter 2022 MTR FEED Report.

[43] Project Tundra: Postcombustion Carbon Capture on the Milton R. Young Station in North Dakota, NRECA Update, October 2022.

[44] Crane, C., *Large-Scale Commercial Carbon Capture Retrofit of the San Juan Generating Station,* Overall Feed Package Report for DOE Cooperative Agreement DE-FE0031843, September 30, 2022.

District Gerald Gentleman,[45] and Prairie State.[46] Figure 4-2 also reports capital cost for one of the hypothetical unit evaluated by NETL: 640 MW (net) with a 10,000 Btu/kwh gross heat rate.[47]

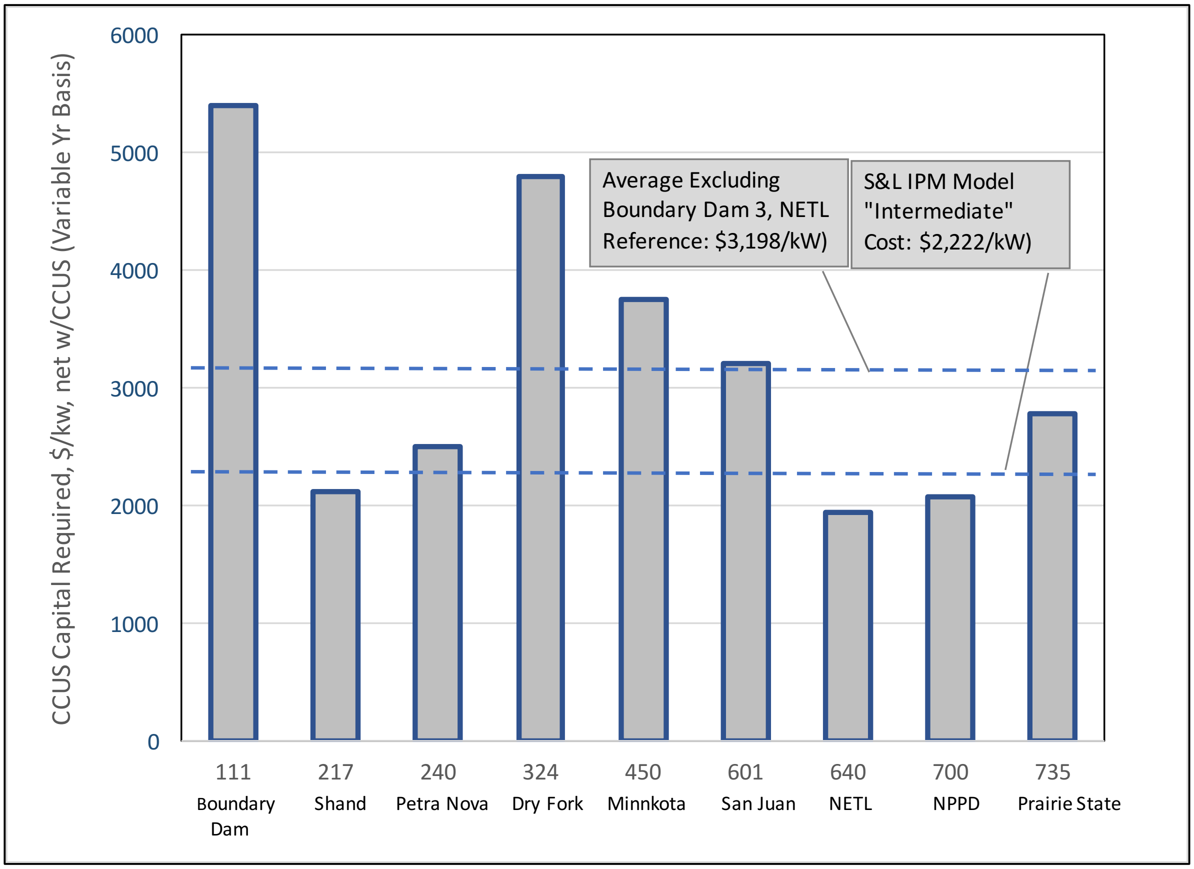

Figure 4-2. CCUS Capital Cost as Reported for Coal-Fired Demonstrations, FEED Studies

Figure 4-2 displays the capital cost from one of EPA's "reference" units (Table 4 of the Steam EGU TSD) used to calculate levelized cost to avoid CO_2 ($/tonne). This calculation, using the S&L IPM model, is conducted for a 400 MW plant with a 10,000 Btu/kWh heat rate, approximating the average conditions of generating capacity and heat rate of units in Figure 4-2. The CCUS capital cost of $2,222/kW $_{\text{(net, with CCUS)}}$ for this reference unit is superimposed on the figure as a reference point for Figure 4-2 results.

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[45] Carbon Capture Design and Costing: Phase 2 (C3DC2), Final Project Report, Final Scientific/Technical Report, DOE-FE0031840, March 2023.

[46] Full-Scale FEED Study for Retrofitting the Prairie State Generating Station with an 816-MWe Capture Plant Using Mitsubishi Heavy Industries America Post-Combustion CO_2 Capture Technology, August 2, 2022. Hereafter 2022 Prairie State FEED Report.

[47] *Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity*, DOE/NETL Report 2023-4320, October 14, 2022. Hereafter 2022 Bituminous/NGCC CCUS Retrofit.

Data in Figure 4-2 vary widely by site. Capital cost *per net generating capacity after CCUS* determined by the FEED studies for all but two units exceeds the $2,222/kW $_{\text{(net, with CCUS)}}$ derived using the S&L IPM procedure for the reference 400 MW unit. The average capital cost from these FEED studies and demonstration tests – excluding the highest and lowest values – provides a more authentic estimate of CCUS capital cost.

Excluding both the highest (Boundary Dam) and lowest (NPPD) costs reported in Figure 4-2, the average capital cost of units in Figure 4-2 is $3,198/kW $_{\text{(net, with CCUS)}}$; a 44% increase to S&L's reference unit. These FEED study results, even though not "benchmarked" to actual data, are transparent and can be reviewed – unlike costs generated by the S&L IPM model, which include "proprietary data".[48]

It is important to recognize capital cost data in Figure 4-2 reflects only CO_2 capture, compression, and preparation for transport from the fence line – but not for transport to the sequestration or EOR site, injection, and plume monitoring.

Sites requiring minimal pipeline length still incur significant costs for the sequestration step. Two example sites for which information is available are the Minnkota Power and Petra Nova projects.

Minnkota Power's Milton R. Young Station. This site requires only 0.5 mile of pipeline for CO_2 transport to the sequestration site. However, additional facilities are required for substations for CO_2 metering and pumps, monitoring for seismic activity, and plume migration. The injection of CO_2 requires four wells drilled – three for injection and one for subsurface monitoring – to be as deep as 10,000 feet. Environmental monitoring instrumentation as required for Underground Injection Control (UIC) Class VI wells is included to assure successful sequestration, as well as financial assurance in accordance with the regulatory requirements of UIC Class VI wells. These ancillary support facilities and provisions are estimated to require an additional $100M – or, $289/kW $_{\text{(net, after CCUS)}}$.

Petra Nova. Section 3.3.2 reports of the $1B for all activities, $600 M was devoted to CO_2 capture at the plant site with the remaining $400 million dedicated to, among other needs, the CO_2 transport and upgrade of the West Ranch site. This includes the cost for the 81-mile CO_2 pipeline and for upgrading the oilfield wells to accept more CO_2 for EOR. As a transparent accounting of projects cost has not been released, it is not known how much of the $400 M is dedicated to these activities.

[48] S&L 2023 CO_2 IPM, page 3. "Cost algorithms developed for the IPM model are based primarily on a statistical evaluation of cost data available from various industry publications as well as Sargent & Lundy's proprietary database and do not take into consideration site-specific cost issues. By necessity, the cost algorithms were designed to require minimal site-specific information and were based only on a limited number of inputs such as unit size, gross heat rate, baseline emissions, removal efficiency, fuel type, and a subjective retrofit factor."

4.4 Inadequate Basis for Levelized $/Tonne Calculation

EPA employs different methodologies to calculate the levelized cost to avoid CO_2 ($/tonne), including the impact of the IRA. EPA's calculations are recorded in the docket.[49]

EPA's calculation methodology is reviewed in this section to document shortcomings. However, as stated previously, CCUS is not BSER and cost are not confidently defined; thus, EPA's calculations are speculative and do not reflect present state-of-art in the proposed rulemaking docket.

EPA calculations presented in Table 8 of the Steam EGU TSD, which defined levelized cost per (short) ton including the benefits of the IRA, are invalid for numerous reasons. First, as noted in Section 4.3.1., the capital cost used by EPA for this calculation is derived from the S&L IPM model, for "hypothetical" sites. As noted in Section 4.3.1, this source does not provide capital cost "referenced" to a specific site, nor based on fully transparent data. The example 400 MW unit with a 10,000 Btu/kWh heat rate is assigned a cost of $2,222/$/kW $_{\text{(net, with CCUS)}}$ 31% less than capital from FEED studies ($3,198/$/kW $_{\text{(net, with CCUS)}}$).

Second, calculations are based on the optimistic premise that the CCUS process will operate at 100% availability, thus always be available to accrue tax benefits and defray operating cost. As the bulk of CCUS costs are capital, incurred whether the unit is operating or not, periods of restricted duty will limit CO_2 delivered and tax benefits. A compromise in availability directly affects the calculated cost to avoid CO_2.

Table 4-1 compares the levelized cost per ton ($/ton) for EPA's optimistic case, and two sensitivity cases that explore the role of CCUS capital cost and process availability.[50] Table 4-1 presents EPA's results as calculated using Tables 8 and 9 Steam EGU assumptions, the "intermediate" capital cost ($2,222/kW $_{\text{(net, with CCUS)}}$), and perfect availability (100%). The costs are presented for 50% and 70% capacity factor and include the benefit of the IRA.[51] Also shown are results to sensitivity analysis.

[49] EPA-HQ-OAR-2023_0072-0061_attachment_3.

[50] It should be noted the author could not corroborate why Table 8 of the Steam EGU TSD specifies the variable O&M cost used in the calculation is $5/MWh, compared to $23/MWh reported by the S&L IPM source document for what appears to be comparable conditions. For the purpose of this report, calculations adopt EPA's $5/MWh to assure a valid comparison. However, the difference is noted and should be further explored.

[51] The "negative" costs presented in Table 4-1 for two cases reflect EPA's projection that CO_2 removal and sequestration will comprise a profitable venture.

Table 4-1. Sensitivity: Role of Capital Cost, CCUS Availability of Projected CO_2 $/tonne

Capacity Factor (%)	EPA Assumption			FEED Study Average		
	Capital Cost ($/kW)	CCUS Availability	$/Tonne	Capital Cost ($/kW)	CCUS Availability	$/Tonne
50	2,222	100%	15	3,198	100	49
50	2,222	90	23	3,198	90	53
70	2,222	100	-9	3,198	100	15
70	2,222	90	-2	3,198	90	23

The sensitivity of the levelized cost (including IRA benefits) to avoided CO_2 ($/tonne) to changes in CCUS capital and reliability are described as follows:

EPA Capital, Compromised CCUS Availability. This case retains EPA's capital cost of $2,222/kW $_{\text{(net, with CCUS)}}$, but recognizes that – as witnessed at Sask Power and Petra Nova - CCUS availability is less than 100%. Results for the two capacity factors are as follows:

- Perfect (100%) Availability. Estimated $/tonne cost is reported as $15 at 50% and -$9 at 70% capacity factor.
- Compromised (90%) Availability. Estimated $/tonne costs elevates to $23 at 50% and -$2 at 70% capacity factor.

FEED Study Capital, Compromised CCUS Availability. Applying the average FEED study capital of $3,198/kW $_{\text{(net, with CCUS)}}$ for 100% and 90% CCUS reliability derives the following:

- Perfect (100%) Availability. Estimated $/tonne costs elevates to $49 for at 50% and $15 at 70% capacity factor.
- Compromised (90%) Availability. Estimated $/tonne costs elevates to $53 for at 50% and $23 at 70% capacity factor.

It should be noted that – without the IRA subsidy - the cost to avoid CO_2 per tonne for some cases is a factor of 10 higher compared to 100% CCUS reliability. For capital cost of $3,198/kW $_{\text{(net, with CCUS)}}$ the levelized cost to avoid CO_2 at 50% capacity factor is $127 and at 70% capacity factor is $93.

In Summary:

EPA estimates of CCUS capital cost for coal applications in Tables 6 and 7 of the Steam EGU TSD are low. A more authentic source is the average capital cost derived from the two demonstrations and FEED studies, eliminating the high (Boundary Dam 3) and lowest (NPPD) cost units. This source projects a cost of $3,198, a 43% premium to that generated by the IPM model. Revised estimates of $/tonne incurred – using FEED-study capital cost and accounting for a 10% compromise in CCUS reliability - increase cost calculated for 50% capacity factor from $23 to $53/tonne with the IRA credit, and for 70% capacity factor from -$2 to $23/tonne *if CCUS works as planned for at least 12 years*.

5 CO2 Pipeline Permitting Issues

Broad CCUS deployment will require a significant increase in CO_2 pipeline capacity. Securing new pipelines requires design, permitting, and construction tasks – all within a time frame that will not delay the entire project. Section 5 presents examples of ongoing permitting conflicts, demonstrating how delays can be incurred. The takeaway from this discussion is used in the critique of the CCUS implementation schedule presented in Section 6.

5.1 Background

Deploying CCUS to numerous generating units – such as the 39 units EPA estimates to deploy per the 2023 Integrated Baseline Analysis - requires expanding CO_2 pipelines capability. One limiting step to CCUS deployment is acquiring the necessary right-of-way for pipelines to transport the CO_2. EPA in their projected CCUS schedule estimate 130 weeks to be required for permitting a pipeline. The Global CCS Institute assumes that in acquiring pipeline access during their proposed almost 9-year schedule "…. there is no significant community opposition."[52]

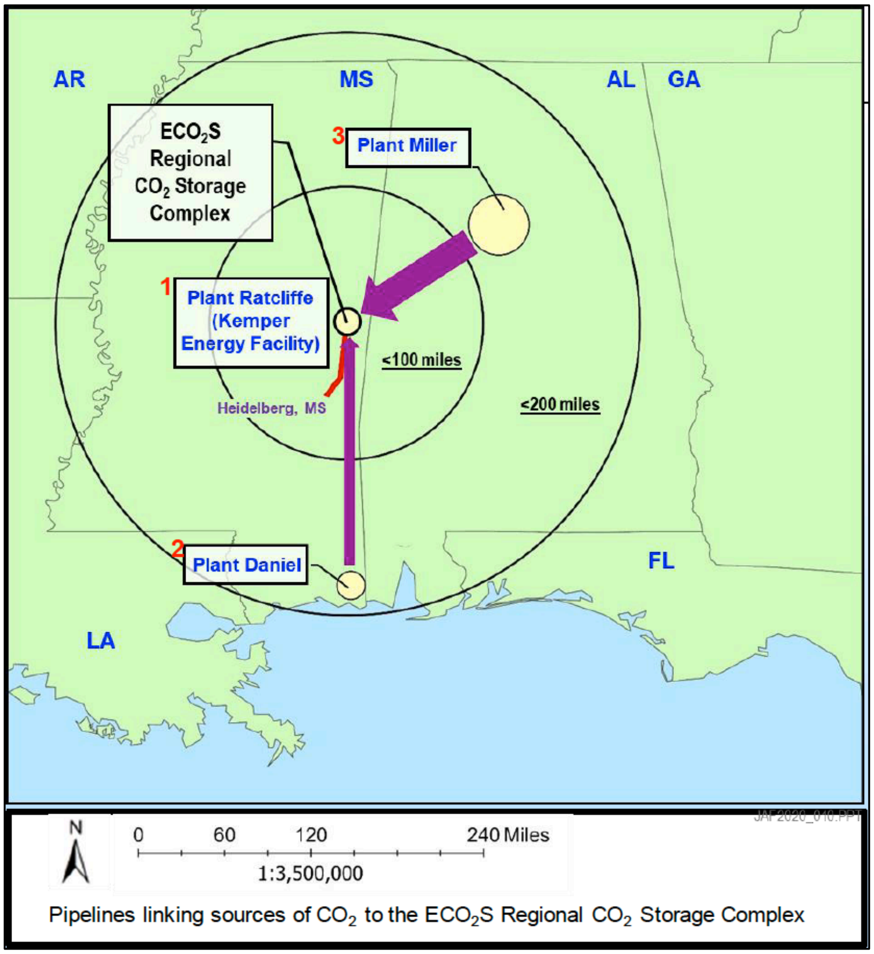
A key factor in the schedule is the pipeline length to access either EOR or terrestrial sequestration. Each additional mile of pipeline requires additional owners' land to access and acquire right-of-way. Pipeline permitting issues are addressed following a brief discussion of pipeline length.

5.1.1 Pipeline Length

The length of the pipeline to transport CO_2 from candidate CCUS sites can vary by an order of magnitude. This range is evidenced by several units that have completed CCUS FEED studies. The CO_2 pipeline length for projects located adjacent to the generating site – such as for Project Tundra at the coal-fired Dry Fork station, and the Elk Hills NGCC application – are less than a few miles. Conversely, and as shown in Figure 5-1, the pipeline length necessary to transport CO_2 to the ECO2S Regional Storage Complex from Mississippi Power's Daniel Unit 4 is 180 miles and from Plant Miller 150 miles.[53] Although it appears desirable to rely on CCUS installations on units located at or adjacent to a disposition site, such a strategy is unrealistic as host units may not have favorable characteristics (generating capacity, capacity factor, remaining lifetime).

[52] CCS Institute report 20-22; p. 48/.

[53] Riestenberg, D. et. al., Establishing an Early Carbon Dioxide Storage Complex in Kemper County, MI: Project EICO2S, 2020 DOE/NETL Integrated Review Webinar, August 17-19, 2020. Hereafter 2020 Kemper County Storage Complex.



Pipelines linking sources of CO_2 to the ECO_2S Regional CO_2 Storage Complex

Figure 5-1. Candidate CO_2 Pipeline Routing, Length: Plants Daniel and Miller

Both the DOE and EPA adopt a typical pipeline length to be 100 km – 62 miles – for which there is no technical basis; EPA concedes this assumption as a means for "standardization".[54] The DOE applies this "default" 100 km pipeline length in their cost evaluation for "hypothetical" plant. EPA states "…. there are 43 States containing areas within 100 km from currently assessed onshore or offshore storage resources in deep saline formations, unmineable coal seams, and depleted oil and gas reservoirs";[55] this observation is inadequate to justify the 100-km length as a default.

Pipeline length will be driven by finding adequate storage volume to accept the CO_2 quantity from a large generating unit; it is unlikely the required storage will be located at the nearest boundary of any terrestrial basin. The NETL Atlas[56] - developed to provide "high-level" assessment and not a detailed assay of disposition sites - reveals significant heterogeneity of features that affect CO_2 injection rate and storage. The quantity of CO_2 to be stored for a coal-

[54] GHG Proposed Rule, footnote #333.

[55] Ibid; 33298.

[56] NETL Carbon Storage Atlas; Fifth Edition, DOE Office of Fossil Energy, August 2015. Hereafter 2015 DOE/NETL Storage Atlas.

fired or NGCC unit of generating capacity large enough for CCUS to be feasible (i.e., 400 MW or more) is far greater than demonstrated at all but a few sequestration sites permitted to date. The Global CCS Institute reports 22 projects either in operation or construction for 2024 or 2025 duty with only two sequestering 5 or more million tonnes of CO_2 per year (Mt/a).[57]

In summary, EPA's assumption of a 100-km average pipeline length to access an acceptable reservoir for power generation units is not substantiated.

Section 7 presents a graphic depicting arrangement of the 39 units projected by EPA to adopt CCUS, showing the "footprint" required for pipelines of 100 and 200 km.

5.1.2 Pipeline Projects: Select Description

The Midwest is the nexus for CO_2 pipeline permitting. Several entities are well into the process of developing pipelines to acquire CO_2 from ethanol facilities. The major actors are Summit/Midwest Carbon Solutions, Navigator, and Wolf Carbon. Key features of each project are summarized as follows:

- Navigator[58] proposes 900-mile pipeline bisecting Iowa from northwest to southeast and transporting CO_2 to Illinois. (~$3.2B). A total of 1,300 miles via South Dakota, Nebraska, Minnesota, in addition to Iowa, is proposed. The permit application was filed in July 2022.

- Wolf Carbon[59] proposes 280 miles of pipeline to transport CO_2 from ADM ethanol producing facilities in eastern Iowa to Decatur, IL for terrestrial sequestration.

- Summit Carbon[60] will build 700 miles of pipeline in western and northern Iowa to transport CO_2 to North Dakota, for existing EOR application. In Iowa alone, the proposed pipeline will cross 30 counties.[61]

These entities are pursuing pipeline permits in several states: Iowa, Minnesota, North Dakota, Nebraska, and South Dakota. The permitting requirements vary significantly by state –Iowa presents perhaps the most structured "steps", and Nebraska the least. The lack of structured steps currently in Nebraska does not imply permitting requirements are less strict than Iowa; but that Nebraska's process for permitting CO_2 pipelines is evolving.

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57 *Global Status of CCS 2022*, issued by the Global CCS Institute. Section 6.2. Available at https://www.globalccsinstitute.com/resources/global-status-of-ccs-2022/

58 https://heartlandgreenway.com/about-us/

59 https://wolfcarbonsolutions.com/mt-simon-hub/.

60 https://summitcarbonsolutions.com/project-footprint/.

61 *Proposed Iowa Pipeline Would Cross 30 Counties*, Radio Iowa, Aug 20, 2021. https://www.radioiowa.com/2021/08/30/proposed-carbon-dioxide-pipeline-would-cross-30-iowa-counties/

Landowners cite several reasons for resisting access to their property. One frequent reason cited is concern that agricultural productivity is compromised within the pipeline easements – meaning productivity is reduced 15% for corn and 25% for soy.[62]

5.2 Permitting Experience

Both the EPA's and the Global CCS Institute's treatment of pipeline permitting is unrealistic. This section will report opposition caused by "grass-roots" entities, with support from organizations such as the Eco-Justice Collaborative and the Sierra Club. These organizations, among others, promote campaigns to resist pipeline permits; in Illinois providing an on-line petition.[63]

Each state presents different barriers – and opportunities – to pipeline permitting and construction. Within each state, perhaps the most contentious issue is eminent domain – which a project developer can invoke if they argue the proposed pipeline is of "public use or public convenience and necessity." Success in this argument enables acquisition accompanied by fair compensation.

5.2.1 Iowa

CO_2 pipelines could be of paramount importance in Iowa, as ethanol production asserts significant financial impact on the state and is the major CO_2 source. A total of 57% of corn farmed in Iowa processed for ethanol. Iowa is noteworthy in that pipeline permitting, design, and construction decisions are controlled by a governing body – the Iowa Utilities Board (IUB).[64] The permitting process consists of (a) sponsoring public information meetings in each county, (b) allowing developers 30 days after the public meetings to file a petition for a permit, and (c) establishing a schedule for public hearings, including pre-hearing filing dates for testimonies and exhibits. Upon completing these events, IUB can render a decision.

All three developers propose pipelines in Iowa – 830 miles by Navigator; 95 miles (eastern Iowa) by Wolf Carbon; and 2,000 miles (northern and western Iowa) by Summit. A total of 48% of pipeline length proposed by the Navigator and Summit projects are in Iowa.

The numerous barriers to the pipeline pre-feasibility work and permitting in Iowa are summarized as follows:

<u>Survey Access</u>. Iowa law – as presently enacted - allows pipeline companies access to proposed easements for survey, with the requirement that informational meetings are sponsored and

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[62] Pipeline study shows soil compaction and crop yield impacts in construction right-of-way, Iowa state university College of Agricultural and Life sciences, November 11, 2021. Available at https://www.cals.iastate.edu/news/releases/pipeline-study-shows-soil-compaction-and-crop-yield-impacts-construction-right-way

[63] https://noillinoisco2pipelines.org/

[64] https://www.agriculture.com/news/business/landowner-battles-against-pipelines-vary-by-state

landowners notified. The constitutionality of this law is being challenged by four property owners that refuse access the property.[65]

Denial of Right-of-Way. A total of 430 landowners are rejecting offers to sell rights-of-way to CO_2 pipeline owners.

Eminent Domain. Pipeline developers can use eminent domain – at the discretion of the IUB – to build pipelines on the property of owners who refuse to voluntarily comply. Eminent domain decisions are made on an individual case-by-case basis. Resistance to eminent domain is strong - 78% of Iowans oppose its use.[66]

A legal challenge to eminent domain is being considered in Iowa, as follow-on to earlier challenges introduced in 2015.[67] Iowa proposed a bill requiring pipeline developers to acquire right-of-way voluntarily from 90% of landowners prior to invoking eminent domain.[68] An additional challenge to eminent domain is based on rejecting the "public use" argument, despite the claimed CO_2 pipeline benefit of supporting ethanol production.

Approximately 30% of Summit's proposed pipeline route crosses 1,000 parcels of land – for which they have obtained 40% of the required voluntary easements[69] for the 680-mile segment in Iowa. The prospect for eminent domain is of great concern; media cite eminent domain has the potential to elongate the final permit hearing, when eminent domain requests are individually considered.

Finally, some owners are adamant they will not participate:[70]

"When is 'no' accepted as 'no'? How many times do we have to say no? My answer in 2021 for an easement was 'no.' My answer today is 'no.' My answer tomorrow and any days forward will be a resounding 'no.' Our land is not for sale."

5.2.2 Nebraska

Nebraska is reported - at present - to not have established CO_2 permitting requirements; the lack of such requirements is not to be interpreted that Nebraska is – or will be – lenient. For example, in contrast to Iowa where pipeline developers can access sites (under preconditions) for survey, Nebraska has no such rule. Further, proposed legislation in Nebraska will require owners to remove CO_2 pipelines, once the project and CO_2 removal duty is complete. Finally, unlike other states, there is no option of eminent domain.

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65 https://www.agriculture.com/news/business/judge-says-pipeline-survey-lawsuit-should-go-to-trial
66 https://www.agriculture.com/news/business/wolf-carbon-pipeline-plans-might-be-delayed
67 https://www.agriculture.com/news/business/pipeline-company-wants-permit-decision-in-iowa-by-year-s-end
68 https://www.agriculture.com/news/business/house-passes-bill-to-restrict-eminent-domain-for-pipeline
69 https://www.agriculture.com/carbon-pipeline-opponents-decry-sham-process.
70 https://www.agriculture.com/news/business/pipeline-company-wants-permit-decision-in-iowa-by-year-s-end

5.2.3 Illinois

Illinois presently hosts numerous studies of geologic sequestration to support the state's concentration of ethanol production sites. At present, there is a sole – and short – pipeline confined to the ADM ethanol facility in Decatur, routing CO_2 captured for on-site sequestration. However, some observers project Illinois could be a superhighway for CO_2 pipelines.[71] The responsibility for permitting pipelines is with the Illinois Commerce Commission (ICC).

Local resistance exists. McDonough County issued a 2-year moratorium on pipeline approval and permitting actions, primarily to allow for improved federal safety design standards. Separately, a representative of the ICC noted that 14 separate permits for federal, state, and local permits are required for a pipeline, of which none had been acquired as of September 2022.[72]

5.3 Timeline Summary

The currently available timelines for the Summit and Navigator project are summarized as follows:

Navigator. This developer initiated public hearing in 4Q 2021, and as of early 2022 planned to start construction in 2024.

Wolf Carbon. Wolf filed a pipeline permit in February of 2023 with the IUB, and is uncertain that construction could start in the second quarter of 2024.[73] Wolf reports the permit applications do not – at least to date - include a request to use eminent domain.

Summit. Summit filed an initial permit in August 2021 and – upon encountering delays - asked for a decision by the end-of-year of 2024. This timeline requires almost a 3.5-year duration.[74] The Sierra Club – who opposes the pipeline along with select landowners – propose the hearing be delayed to 2024. Summit is reported as of late May 2022 to have signed easements with approximately 30% of the landowners required to complete the pipeline within Iowa.[75]

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[71] Advocates urge Illinois landowners to prepare for risks from CO2 pipelines, March 15, 2022, Energy New Network. Available at https://energynews.us/2022/03/15/advocates-urge-illinois-landowners-to-prepare-for-risks-from-co2-pipelines/

[72] Illinois County Offered Payments to Back Navigator Carbon Dioxide Pipeline, February 3, 2023, Energy New Network. Available at https://energynews.us/2023/02/03/illinois-county-offered-payments-to-back-navigator-carbon-dioxide-pipeline/

[73] https://www.agriculture.com/news/business/wolf-carbon-pipeline-plans-might-be-delayed.

[74] https://www.agriculture.com/news/business/pipeline-company-wants-permit-decision-in-iowa-by-year-s-end

[75] *Strange Bedfellows: Farmers and Big Green Square Off Against Biden and the GOP*, Politico, May 29, 2022. https://www.politico.com/news/2022/05/29/iowa-manchin-carbon-capture-pipeline-00030361

One observer thinks at least 3 years will be required to resolve permit issues; dozens of lawsuits have been filed in Iowa, and North and South Dakota – most initiated by pipeline companies to secure access.[76]

Takeaway: The most evolved reference case for CO_2 pipeline permitting – activities for Summit within Iowa – at present project a 3.5-year timeframe from proposal to final hearing. Abiding by this schedule assumes the final hearing is conducted at end-of-year 2024. This projected timeframe exceeds all schedules projected by EPA.

[76] https://www.agriculture.com/news/business/landowner-battles-against-pipelines-vary-by-state

6 CRITIQUE OF CCUS SCHEDULE

The EPA has proposed a 5-year schedule to execute a CCUS project from concept through delivery of CO_2 for sequestration or EOR. Section 6 critiques EPA's proposal, and demonstrates a 5-year duration is inadequate.

Of eight demonstration projects or FEED studies represented in Figure 4-2, four delivered at least partial schedules. In addition, two FEED studies of CCUS to NGCC units illustrated in Figure 4-3 delivered partial schedules.

None of the proposed schedules support a 5-year timeline for the complete scope to deploy CCUS, or seriously address permitting for sequestration or CO_2 pipelines, much less consider the timelines necessary to finance a CCUS project.

6.1 S&L Proposed Schedule

The EPA sponsored S&L to develop a CCUS schedule, from concept to delivering commercial quantities of CO_2 for disposition. Figure 6-1 presents the image of the schedule in the docket[77] describing a "baseline" duration of 6.25 years and an "extended" duration of 7 years.

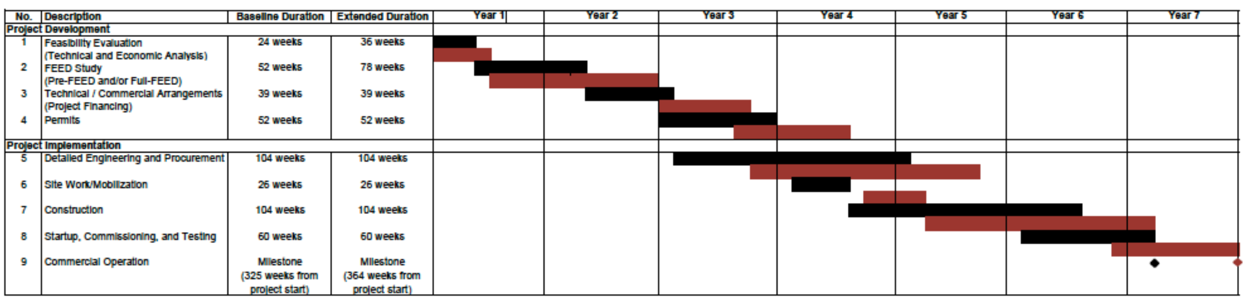

Figure 6-1. S&L CCUS Deployment Schedule

S&L describes the scope of duties addressed in the schedule to include project development (feasibility assessment, FEED studies, developing commercial agreement and technical specifications, permitting, award of contracts) and implementation (detailed engineering, fabrication, construction, startup, commissioning, and testing).

S&L in their supporting material describe two barriers to this schedule, which EPA ignore in the Steam EGU TSD. These barriers are:

<u>Potential Impacts, Road Blocks.</u> S&L list seven potential "schedule impacts" than can impose a delay: equipment fabrication or delivery; weather, underground interferences; challenging site for retrofit; contract negotiations and financing; and – perhaps the largest – public comment

[77] S&L_CCS_Schedule_EPA-HQ-OAR-2023-0072-0061_attachment_16.pdf.

periods. Example "roadblocks" or "bottlenecks" are a limited number of vendors and constructors for work of this scale; infrastructure of steel availability and heavy construction equipment; engineering due to large project volumes.

Incomplete Scope. S&L present a disclaimer stating the schedule addresses on-site activities, excluding those external to the site but critical for project execution.

This schedule is for the on-site CCS system only and does not include the scope associated with the development of the CO2 off-take / storage (including transportation, sequestration, enhanced oil recovery utilization, and/or utilization).

In summary, the S&L schedule does not reflect all activities required for a complete CCUS project, and thus does not represent a realistic timeline.

6.2 Global CCS Institute Schedule

A CCUS schedule proposed by the Global CCS Institute - an organization funded by government entities, and suppliers of process equipment and engineering services - projects an almost 9-year timeline.[78] Figure 6-2 presents this schedule as extracted from the referenced Global Status of CCUS 2022 report.

The Global CCS Institute offers the following context – actually disclaimers – regarding their schedule:

- A large complex CCUS project may take a decade to progress from concept to operation;
- The necessary tenements and approvals for geological storage of CO_2 from regulators, generally requires years to complete; and
- The identification and appraisal of geological resources for the storage of CO_2 is a costly and time-consuming process. These activities typically take a few years to complete and are subject to the availability of geoscientists with appropriate experience and the critical equipment required to collect data and drill wells.[79]

The Global CCS Institute report does identify conditions where a shorter timeline is feasible, and such sites may exist. It is noteworthy EPA's assumption of 5 years for broad deployment is almost half of that projected by an organization whose objective is to promote CCUS.

[78] *Global Status of CCS 2022*, issued by the Global CCS Institute. P. 47. Available at https://www.globalccsinstitute.com/resources/global-status-of-ccs-2022/

[79] Ibid. at pgs. 47-48.

FIGURE 28: SIMPLIFIED GANTT CHART FOR A COMPLEX CCS PROJECT

Figure 6-2. Global CCS Institute Deployment Schedule

6.3 EPA's Compressed Schedule

The schedule EPA presents in the Steam EGU TSD is a compressed version of the schedule developed by S&L. S&L does not consider the transport and disposition of CO_2 off-site within their timeline scope; EPA proposes a schedule for this task. EPA advises between one to two years are required for a sequestration site feasibility study, characterization, and permitting.[80] EPA cite as evidence source material that is not convincing or supportive: (a) site characterization and permitting for a 10 MW pilot plant – generating a small fraction of the CO_2 produced by a commercial plant, and that will operate for 5 years;[81] and a management overview of the four phases of the CarbonSafe program (that total more than 5 years).[82] EPA's third example is experience of a project in North Dakota, a state with primacy, in securing a sequestration permit, but absent documentation of a final schedule certifying permits-in-hand (although cautioning "Pore space acquisition takes more time than you think".)[83] These citations

[80] Steam EGU TSD. P. 36.

[81] Large Pilot Testing of Linde-BASF Advanced Post-Combustion Carbon Dioxide Capture Technology at a Coal-Fired Power Plant. Available at https://www.netl.doe.gov/projects/project-information.aspx?k=FE0031581

[82] CarbonSafe Storage Assurance Facility Enterprise: Available at: https://netl.doe.gov/sites/default/files/2022-05/IG-CarbonSAFE_20220512.pdf

[83] Peck, W., North Dakota CarbonSafe Phase III: Site Characterization and Permitting, August 2, 2021, available at https://netl.doe.gov/sites/default/files/netl-file/21CMOG_CCUS_Peck.pdf

do not support EPA's 104 week duration for site characterization and permitting that is included in their 5-year schedule. Similarly, no evidence is offered to support their 130 weeks estimate for pipeline design, feasibility, permitting.

EPA – quite arbitrarily – elected to compress the schedule proposed by S&L. Specifically, EPA states:

> *EPA believes that a five-year project timeline for deploying CCS, and related infrastructure and equipment, is reasonable. There are opportunities to compress schedules, expedite certain portions of the project schedule that are amenable to faster timetables, and conduct various components of the schedule concurrently.*
>
> EPA cites no basis for the compression – but describe that "*…sources expedite (where feasible) the scheduled deployment of CCS technology in a reasonable manner in order to meet the timing requirements of this action.* Regarding CO_2 capture design and development actions, EPA opine *"Each of these individual steps need not be in a sequential, and many of these actions can be planned well in advance, such that there can be significant time savings across these project planning steps.*

Finally, EPA ignores risks inherent in emerging technologies, which given uncertainty in hardware design and performance - complicates parallel execution of engineering and procurement. EPA does not consider the risks in procuring components before all design work is complete – which can lead to cost overruns and schedule delay when it becomes necessary to modify the final design, perhaps altering early phases.

The achievable reduction in schedule in most cases is negligible – as to be shown subsequently, most schedules (i.e., Elk Hills) already include "parallel" steps such as final design and construction.

6.4 Authentic CCUS Project Schedules

There are 13 CCUS projects for which schedules have been developed through at least the CO_2 capture. Few CCUS projects completely address the scope from process conception through CO_2 delivery and site injection (for sequestration or EOR). Two of these activities – Sask Power Boundary Dam 3 and Petra Nova – are discussed in Section 3. No other projects can offer authentic experience with a complete project execution, accounting for all uncertainties in design, construction, and permitting.

This subsection reviews available schedule data from projects to compare to the EPA's proposed schedule. Schedules for both NGCC and coal-fired CCUS projects are considered. This high-level summary provides for each project site, as available, the following: the total project duration, the FEED design (including developing procurement specification) duration, and the period for construction. Comments on each project are offered for additional consideration.

6.4.1 NGCC Schedule

Table 6-1 overviews schedule information for two NGCC applications- Elk Hills and Mississippi Power Plant Daniel - for which information is publicly available addressing schedule.

Table 6-1. Summary Schedule Information: NGCC CCUS Projects

Project/Site	Actions Addressed in Schedule	Pre-FEED FEED Design, Specifications	Post-FEED Design, Construction	Comment
Elk Hills[84]	-CO_2 Site Prep: N/A -pre-FEED -FEED -Design/Const.	12 mos (pre-FEED) 29 mos FEED[85] Design/Spec 24 mos (p.44)	55 mos	96 mos for FEED, other activities. Total ~8 yrs
Plant Daniel	-CO_2 Site prep: ECO_2S (start 2017) -FEED -Design/Const.	20 mos. (FEED: 1/29/20 to 9/30/21[86]	60 mos including final design[87]	80 mos w/o permitting, sequestration

Elk Hills. This 550 MW (net) unit is regarded by the California Energy Commission as highly advantageous for CCUS, and describe it as "…one of the most suitable locations for the extraction of hydrocarbons and the sequestration of CO_2 in North America."[88] Even with these ideal conditions – the generating unit located directly above the sequestration fields that are already characterized - a minimum of 8 years is required. After a presumed 12-month pre-FEED evaluation of CCUS feasibility, the Elk Hills final report describes a 29-month FEED study, followed by 55 months for remaining activities. The activities per the project schedule (Appendix A, Figure A-1) following the 29-month FEED study are (a) 10 months of post-FEED events developing requests for proposal (RFPs), regulatory documentation and approval, and bids for select equipment, and (b) detailed engineering and procurement (parallel activities).

Construction is authorized to start once 60% of detail engineering is complete, and requires 24 months. Figure A-1 shows several major tasks are conducted in parallel.

Summary: The Elk Hills CCUS project benefits from near-ideal site conditions, with access to a well-characterized sequestration site. Despite the absence of delays due to pipeline permitting, this project experience demonstrates a project timeline between eight and nine years.

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[84] 2022 Elk Hills FEED Report. Page 1220.

[85] Front-End Engineering Design Study for Retrofit Post-Combustion Carbon Capture on a Natural Gas Combined Cycle Power Plant, Graphics Deck per DE-FE00311842, February, 2022. Page 6.

[86] Front End Engineering Design of Linde-BASF Advanced Post-Combustion CO_2 Capture Technology at a Southern Company Natural Gas-Fired Plant, Virtual Meeting Graphics deck, Aug 2, 2021. P.21.

[87] 2022 Daniel FEED Report.

[88] Appendix F, URS Report on CO_2 Sequestration for California Energy Commission. 2010

Mississippi Power Plant Daniel. This 525 MW (net) unit was evaluated in FEED study to retrofit the Linde-BASF amine-absorption process. A potential schedule describing activities from concept evaluation to CO2 delivery – exclusive of permitting - can be considered, recognizing work began in 2017 to characterize the likely CO_2 sequestration site (Kemper County Storage Complex).[89] Consequently, considering the FEED study (30 months) and Final Design/Construction (60 mos) totals almost 7 years; but this does not account for the work completed since 2017 to evaluate sequestration options at the Kemper County Storage Complex. In addition, pipeline issues are not addressed – which as shown by experience in Iowa, could induce delays in the permitting, design, and construction of the 181mile pipeline segment.

Summary. A realistic timeline for CCUS as represented for Daniel 4 is similar to that described by Southern Company in previous comments addressing NGCC units.[90] This timeline – including technology evaluation, site permitting, process installation, and ramp-up for sustained operation – describes 10 years as necessary.

6.4.2 Coal-Fired CCUS Applications

Table 6-2 overviews schedule information for coal-fired applications, including Sask Power Boundary Dam 3 and Petra Nova. The implementation schedule for these projects is presented in Section 3.3.

Table 6-2. Summary Schedule Information: Coal-fired CCUS Projects

Project/Site	Actions Addressed in Schedule	Pre-FEED FEED Design, Specifications	Post-FEED Design, Construction	Comment
Sask Power	Per Sask Power: Commitment to completion[91]		3 yrs	6 yrs: Concept to completion. Existing EOR site, limited pipeline
Petra Nova[92]	6/10 to 12/16	Not specified	2014-2016[93]	80-mile pipeline to existing pipeline to EOR site.

[89] 2020 Kemper County Storage Complex.

[90] Comments of Southern Company to EPA's Pre-Proposal Docket on Greenhouse Gas Regulations for Fossil Fuel-fired Power Plants, Docket ID No. EPA-HQ-OAR-2022-0723, December 21, 2022.

[91] SaskPower's Boundary Dam Carbon Capture Project Wins Powers Highest Award, Power, https://www.powermag.com/saskpowers-boundary-dam-carbon-capture-project-wins-powers-highest-award/

[92] WA Parish Post-Combustion CO2 Capture and Sequestration Project, Topical Report: Final Public Design Report, Award No. DE-FE0003311. Pages 7, 8.

[93] https://www.businesswire.com/news/home/20170109006496/en/NRG-Energy-JX-Nippon-Complete-World%E2%80%99s-Largest

Table 6-2. Summary Schedule Information: Coal-fired CCUS Projects (Cont'd)

Project/Site	Actions Addressed in Schedule	Pre-FEED FEED Design, Specifications	Post-FEED Design, Construction	Comment
Basin Electric/Dry Fork[94]	Storage feasibility (March 2017)[95] to Oct 2029 CO_2 injection	FEED. Oct 2019 to June 2022 (32 mos.)[96] Pilot study: 2022-2025	July 2025 – Oct 2029 for 1st CO_2 capture [97]	Detailed design start July 2025 to assure operation by Jan 2032[98]
Minnkota Power/Milton R. Young[99]	-Storage feasibility (2015+), pilot plant -pre-FEED -FEED -Final Design/Con.	FEED: 2019 thru 2021 (24 mos.) Detailed Engineering and 6-12 mos. for vendor review, selection	Q1-2024 2028.	Total duration: 2015-2028/2029 Permitting duration not typical due to "primacy", adjacent sequestration site.
Prairie State[100]	-Illinois Corridor -FEED -Final Design/Con.	2/3/20 - 11/30/21 (22 months)[101]	EPC: 8/23 thru 4/27 (3.75 yrs)[102]	CO_2 disposition in Illinois Corridor started in 2007
San Juan[103]	-pre-FEED -FEED	5/22/2020-10/29/2021[104]	2/12/24 thru 6/04/26	21-mile pipeline not addressed
Shand	-pre-FEED -FEED/Final design	-pre-FEED complete -FEED 18 months[105]	Detailed Design/Constr 36 months[106]	

[94] 2022 MTR FEED Report

[95] Wyoming CarbonSAFE Phase II: Storage Complex Feasibility (Commercial-Scale Carbon Storage Complex Feasibility Study at Dry Fork Station, Wyoming. DE-FE0031624, April 30, 2021.

[96] Commercial-Scale Front End Engineering Design (FEED) Study for MTR's Membrane CO2 Capture Process, Project Closeout Meeting, June 24, 2022. See graphic 3.

[97] Ibid.

[98] DE-FE0031846 page 38.

[99] Project Tundra: Postcombustion Carbon Capture on the Milton R Young Station, NRECA Update, October, 2022.

[100] 2022 Prairie State FEED Report. Page 145.

[101] Full-Scale FEED Study for Retrofitting the Prairie State Generating Station with an 816 MWe Capture Plant using Mitsubishi Heavy Industries Post-Combustion CO2 Capture Technology, DOE/NETL Project Closeout Meeting, June 14, 2022. See Graphic 12.

[102] Ibid. See graphic 41.

[103] Enchant Energy City of Farmington: San Juan Generating Station Carbon Capture – Final FEED Presentation, FE0031843. Graphic 42.

[104] Selch, J. et. al., *Large-Scale Commercial Capture Retrofit of the San Juan Generating Station*, FOA-0002058, Carbon Capture Front End Engineering Studies and CarbonSafe 2020 Webinar, August, 2020.

[105] The Shand SSC Feasibility Study: Public Report, International CCS Knowledge Center, November 2018, P. 115

[106] Ibid.

Basin Electric/Dry Fork. This 440 MW (net) unit is the subject of a FEED study of the MTR Polaris membrane CO_2 separation technology. Activities at this site initiated in 2017, as part of the Wyoming CarbonSAFE studies, to determine the feasibility of nearby saline reservoirs (within 10 miles) for sequestration. A FEED study was completed in 32 months, ending June 2022. Per recommendation by S&L, MTR is constructing a 10 MW pilot plant to refine the MTR process design. Pending additional pilot plant test results and project commitment decisions, detailed design is projected to start July 1, 2025, with construction completed to enable CO_2 delivery and injection by December 2029.

Summary: As characterization of site for sequestration initiated in March 2017, a 12-year duration is projected required for this activity, *pending success with pilot plant results*.

Minnkota Power/Milton R. Young. Figure A-2 in Appendix A presents a timeline for activities from process feasibility to CO_2 injection, for retrofit of Fluor's Econamine FG Plus^{SM} process to flue gas generated from 477 MW(net) Unit 2 and 230 MW (net) Unit 1, with sequestration at the plant site. Activities initiated in 2015, consisting of evaluating terrestrial characteristics affecting CO_2 sequestration, and pilot plant tests in host unit flue gas to determine the longevity of amine sorbents. Subsequent work was a pre-FEED study in 2017, followed by a full FEED initiating in 2018 and completed in mid-2022.

Pending an affirmative financial investment decision in early 2024, process engineering will initiate, consisting of vendor solicitation, review, and contract award. A 42-month period is reserved for construction, shakedown testing, and CO_2 injection by year-end of 2028.[107] Permits for CO_2 injection wells in North Dakota is enabled by the states authority to permit geologic carbon sequestration facilities as Class VI injection wells under the Safe Drinking Water Act's (SDWA) Underground Injection Control (UIC) program.

Summary: This 12-year timeline reflects work directed for CCUS technology demonstration; there are limited opportunities to compress this schedule.

Prairie State Generating Station. Prairie State Generating Company was host site for a FEED study of CCUS on one of the 816 MW (gross) units, Unit 2. The analysis has produced a conceptual design and construction plan for the MHI KM-CDR process, as tested by the Petra Nova project. The Prairie State FEED study application was distinguished from previous application due to the type of coal being utilized and the size of the unit.

This project timeline is defined by both CO_2 capture studies, final design, and construction/commissioning, as well as evaluation of sequestration options in the Illinois Storage Corridor.[108] Also, as addressed in Section 5, CO_2 pipeline permitting issues are likely to be encountered, based on early observations of Illinois experience.

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[107] As described in comments to this rulemaking docket by Otter Tail Power, work to characterize the Milton R. Young site built upon work by the University of North Dakota Energy and Environmental Research Center.

[108] Greenburg, S., *Illinois Basin Decatur Project, Assessment of Geologic Carbon Sequestration Options in the Illinois Basin: Phase III*, DOE DE-FC26-05NT42588, July 7, 2021.

The Illinois Basin-Decatur Project – conducted by the Midwest Geological Sequestration Consortium[109] - explored sequestration options that could be utilized by source in Illinois, including Prairie State. These activities, conducted independently of Prairie State, initiated in 2007 as an early element of the Illinois Storage Corridor project. The results identified potential sequestration options for up to the 6 million tonnes /year of CO_2 generated by Prairie State.[110] The original scope of the FEED study of the MHI KM-CDR CO_2 capture process required 23 months (February 2020 through December 2021). The FEED study was then extended by 6 months, to June 30, 2022. The final phase of detailed engineering, procurement, and construction, described in Figure A-3 of Appendix A, was originally estimated to require 3.75 years. This work has not commenced.

Summary: The timeline for sequestration options and acquiring CO_2 pipeline permits within the Illinois Storage Corridor will require further evaluation and analysis. As reported in their comments submitted as part of this rulemaking, a timeline representing Prairie State project conception to CO_2 injection for sequestration is anticipated to require as much as 8 to 10 years.

<u>San Juan Generating Station.</u> Enchant Energy proposed to acquire the San Juan Generating Station in 2022, and deploy CCUS to Units 1 and 4, totaling 877 MW(net) capacity. A preliminary FEED study was completed evaluating retrofit of the MHI process to these western bituminous coal-fired units. This study was conducted from 5/22/2020 through 10/29/2021. Subsequently, a FEED study addressing engineering, procurement, and a preliminary evaluation of construction requirements was initiated in October 2022. The resulting schedule describes construction initiating in early 2024 and being completed in mid-2026, followed by commissioning and testing, enabling commercial duty in September 2027.

This work included an early permit for CO_2 pipeline to access to Cortez EOR pipeline; permitting activity was not completed.

Summary: This project – absent final permitting for a 21-mile pipeline – as planned would require 7.25 years without pipeline construction supporting access to EOR, or CO_2 sequestration site injection.

<u>Shand.</u> A general discussion of Shand states a project investment decision for 2029 CCUS duty should be made in 2024/2025; presumably this investment decision is predicated upon a satisfactory FEED-type study to "de-risk" the decision. This FEED study is projected by Sask Power to require 18 months; accelerating the "start" of activities to 2022/2023. No discussion of CO_2 disposition actions is addressed; a pipeline of approximately 20 miles is required for Shand to deliver CO_2 to the Boundary Dam site for forwarding to the Weyburn fields for EOR.

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[109] Illinois Basin Decatur Project: An Assessment of Geologic Carbon Sequestration Options in the Illinois Basin: Phase III, DE-FC26-05NT42588, July 7, 2021.
[110] Whitaker, S., Illinois Storage Corridor: Phase 3 CarbonSafe, Update Meeting, November 9, 2021.

Summary. The projected schedule for FEED study through CO_2 delivery per Shand owners appears to be 6-7 years. The final timeline would be determined by any additional work to assure the Weyburn oilfield can effectively utilize the additional CO_2 for EOR, or to open new EOR activities in other nearby regional oil fields and construction and permitting of the pipelines.

7 EPA-PROJECTED CCUS INSTALLATIONS

EPA in the 2023 Integrated Baseline Analysis projects that 39 coal-fired units will adopt CCUS by 2030.[111] The basis for the projection is limited to the IPM model selection of units – based on approximate operating characteristics assigned to each unit – to match the required generation. Table 7-1 identifies these units, which are exemplary only and assigned no significance.

Table 7-1. Units Projected by EPA IPM to Adopt CCUS by 2032

State	Unit ID	Plant Name	Capacity (MW)
Alabama	4	James H Miller Jr	477
Arizona	3,4	Springerville	2 x 281
Colorado	3	Comanche (CO)	501
Colorado	1	Pawnee	0
Florida	BB04	Big Bend	292
Illinois	41	Dallman	135
Illinois	1, 2	Prairie State	2 x 851
Indiana	1, 2	Gibson	2 x 427
Kentucky	2	East Bend	399
Kentucky	1, 2	H L Spurlock	207, 353
Kentucky	4	Mill Creek (KY)	324
Michigan	3, 4	Monroe (MI)	2 x 528
Montana	PC1	Hardin Project	65
North Dakota	1, 2	Antelope Valley	2 x 289
Ohio	2	Cardinal	2 x 407
Texas	BLR2	J K Spruce	538
Texas	1, 2	Oak Grove (TX)	2 x 573
Utah	1, 2, 3	Hunter	320, 292, 314
West Virginia	3	John E Amos	515
West Virginia	1, 2	Mitchell (WV)	2 x 538
Wyoming	1	Dry Fork Station	253
Wyoming	BW73, 74	Jim Bridger	2 x 354
Wyoming	1, 2, 3	Laramie River	3 x 385
Wyoming	3, 1	Wygen 1, 2	53, 56
Wyoming	1	Wygen III	63

[111] EPA 2023 Integrated Baseline Analysis

A detailed critique of EPA's analysis is submitted to this rulemaking docket as part of comments by the Power Generators Air Coalition and the American Public Power Association.[112]

Figures 7-1 and 7-2 depict the location of each of these generating units – "hypothetically" assigned CCUS by the EPA IPM model - on a continental map. Also shown are boundaries for four categories of geologic sequestration (active EOR, deep saline formations, oil and gas reservoirs, and unmineable coal seams), and existing CO_2 pipelines. Each plant is encircled showing a radius of proximity to the sequestration sites or existing pipelines for EOR. Figure 7-1 shows the radius of 100 km and Figure 7-2 shows the radius of 200 km. The cited range of 100 km and 200 km are examples only, and do not represent a recommended or "default" distance for sequestration or EOR access.

[112] Technical Comments on the U.S. Environmental Protection Agency's Integrated Planning Model's Evaluation of the Greenhouse Gas Standards and Guidelines for Fossil Fuel-fired Power Plants – Proposed Rule, prepared by James Marchetti, August 7, 2023.

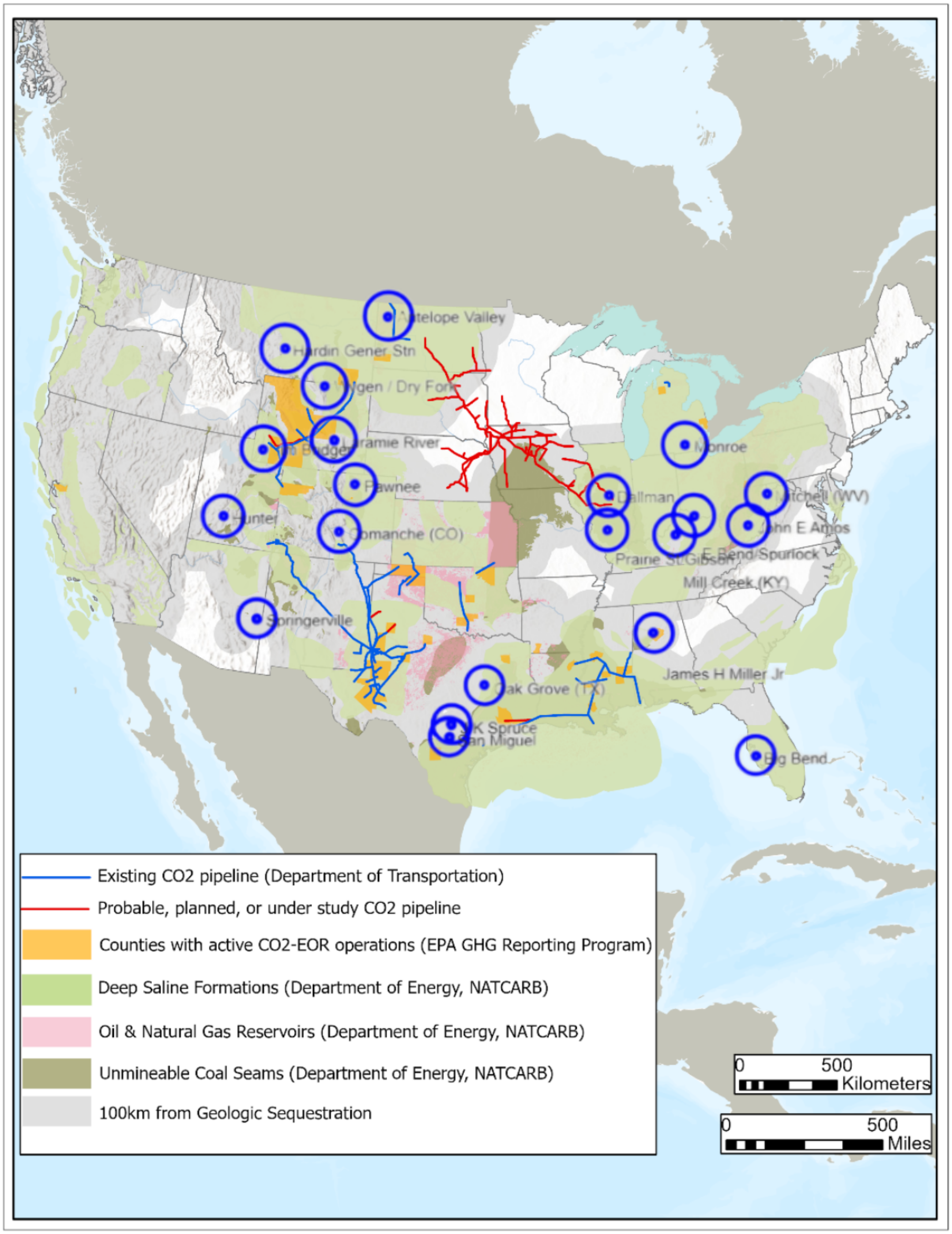


Figure 7-1. Geographic Location of Coal-Fired Generating Units EPA Projects to Retrofit CCUS: 100 km Proximity

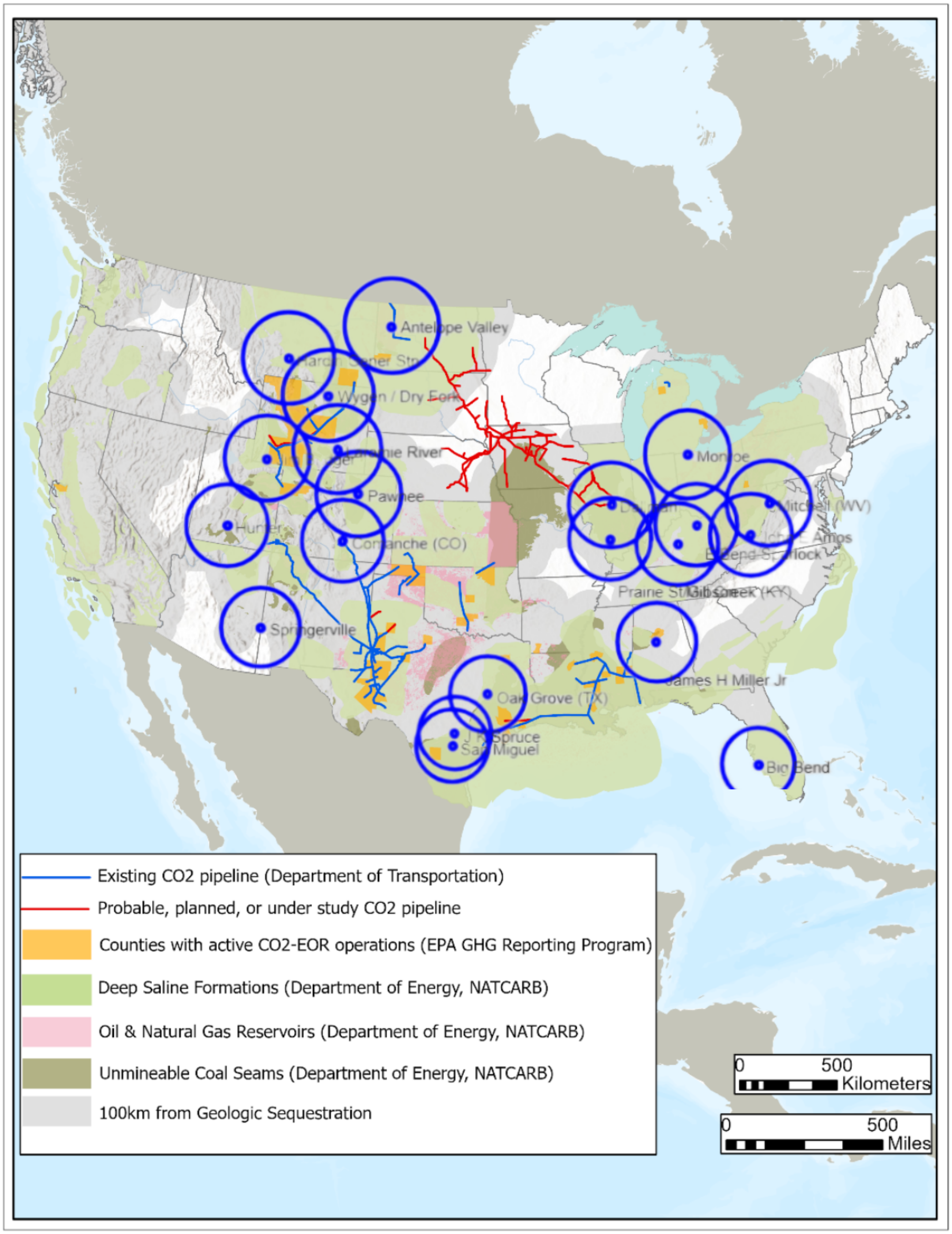


Figure 7-2. Geographic Location of Coal-Fired Generating Units EPA Projects to Retrofit CCUS: 200 km Proximity

Appendix A. Example CCUS Project Schedules

Figure A-1. Elk Hills Project Schedule: Post-FEED Study Activities [113]

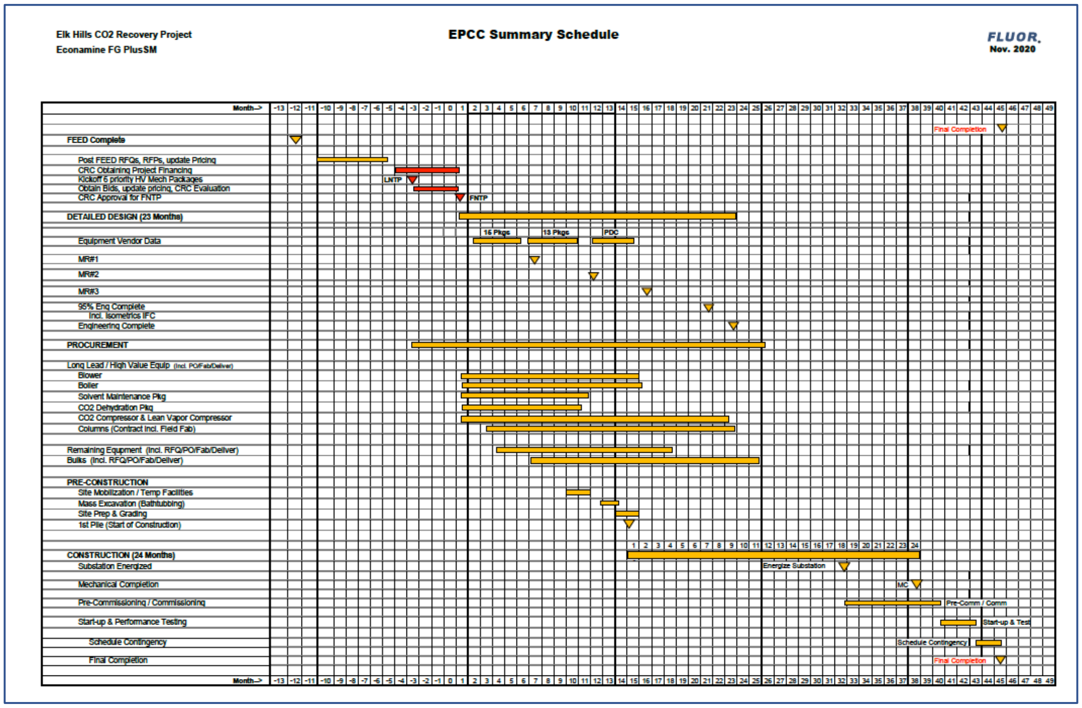
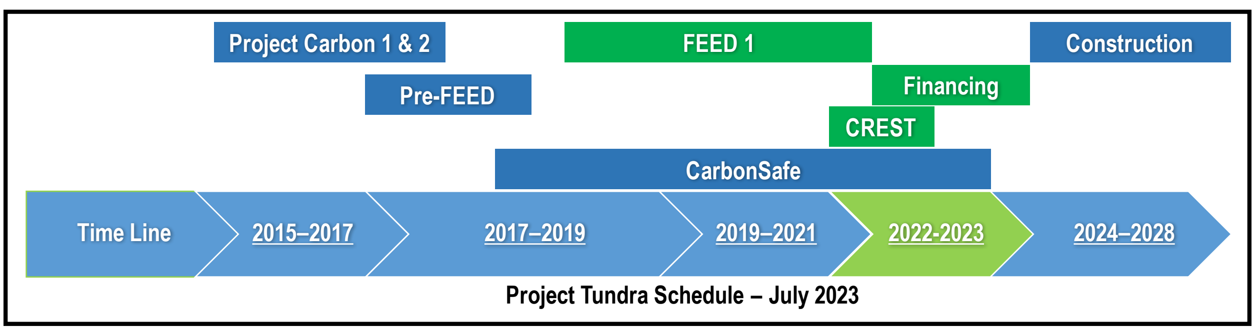


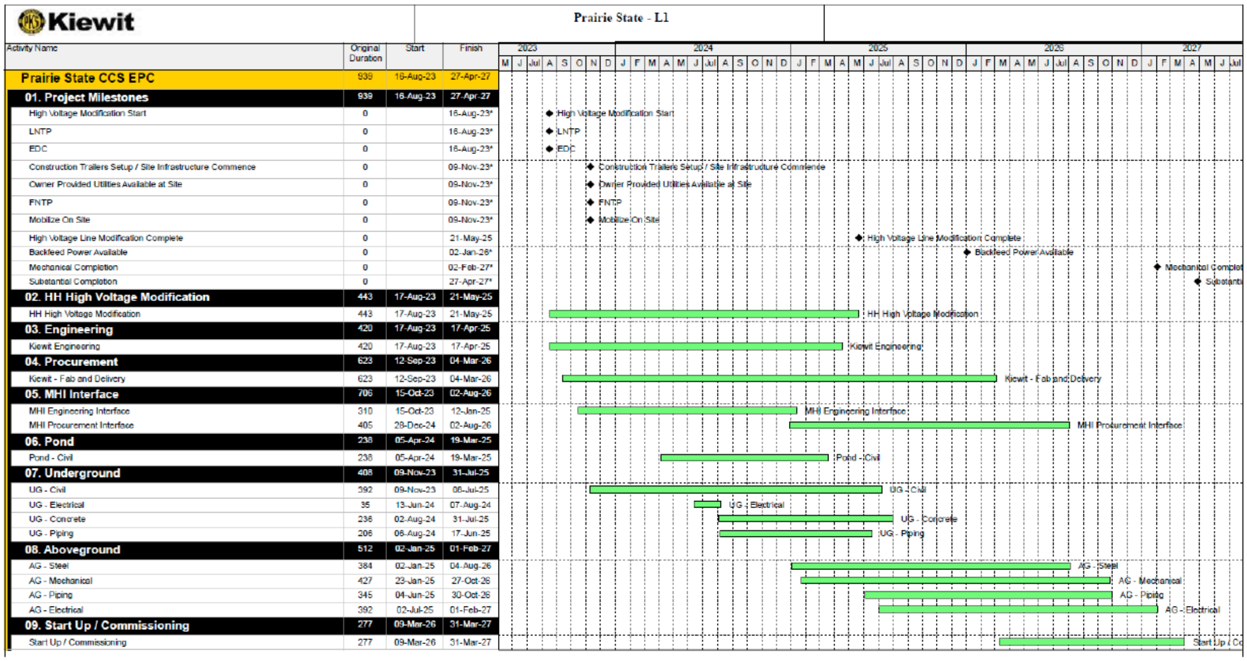
Figure A-2. Minnkota Power Milton R Young Station: Complete Schedule [114]



113 2022 Elk Hills FEED Report.

114 Mikula, S, Personal Communication, July 25, 2023.

Figure A-3. Prairie State Final Engineering, Procurement, Construction Schedule [115]



Activity Name	Original Duration	Start	Finish
Prairie State CCS EPC	939	16-Aug-23	27-Apr-27
01. Project Milestones	939	16-Aug-23	27-Apr-27
High Voltage Modification Start	0		16-Aug-23*
LNTP	0		16-Aug-23*
EDC	0		16-Aug-23*
Construction Trailers Setup / Site Infrastructure Commence	0		09-Nov-23*
Owner Provided Utilities Available at Site	0		09-Nov-23*
FNTP	0		09-Nov-23*
Mobilize On Site	0		09-Nov-23*
High Voltage Line Modification Complete	0		21-May-25
Backfeed Power Available	0		02-Jan-26*
Mechanical Completion	0		02-Feb-27*
Substantial Completion	0		27-Apr-27*
02. HH High Voltage Modification	443	17-Aug-23	21-May-25
HH High Voltage Modification	443	17-Aug-23	21-May-25
03. Engineering	420	17-Aug-23	17-Apr-25
Kiewit Engineering	420	17-Aug-23	17-Apr-25
04. Procurement	623	12-Sep-23	04-Mar-26
Kiewit - Fab and Delivery	623	12-Sep-23	04-Mar-26
05. MHI Interface	706	15-Oct-23	02-Aug-26
MHI Engineering Interface	310	15-Oct-23	12-Jan-25
MHI Procurement Interface	405	28-Dec-24	02-Aug-26
06. Pond	238	05-Apr-24	19-Mar-25
Pond - Civil	238	05-Apr-24	19-Mar-25
07. Underground	408	09-Nov-23	31-Jul-25
UG - Civil	392	09-Nov-23	08-Jul-25
UG - Electrical	35	13-Jun-24	07-Aug-24
UG - Concrete	236	02-Aug-24	31-Jul-25
UG - Piping	206	06-Aug-24	17-Jun-25
08. Aboveground	512	02-Jan-25	01-Feb-27
AG - Steel	384	02-Jan-25	04-Aug-26
AG - Mechanical	427	23-Jan-25	27-Oct-26
AG - Piping	345	04-Jun-25	30-Oct-26
AG - Electrical	392	02-Jul-25	01-Feb-27
09. Start Up / Commissioning	277	09-Mar-26	31-Mar-27
Start Up / Commissioning	277	09-Mar-26	31-Mar-27

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[115] 2022 Prairie State Close Out. At 41.