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Consulting to the Air Pollution Control Industry

# Compliance Options Available to Individual Power Plants Under the Proposed Clean Air Act Section 111 GHG Rules

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to:

Center for Applied Environmental Law and Policy (CAELP)

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# I. Executive Summary

This report examines methods for complying with the U.S. Environmental Protection Agency's (EPA) May 2023 proposed greenhouse gas (GHG) standards for fossil-fuel-fired electric generating units (EGUs). Those standards are developed based on the emissions levels that can be achieved by application of the "best system of emission reduction" (BSER). Individual facilities may comply with the resulting emissions standards through application of the BSER identified by EPA, or individual facilities may comply through other means that can achieve the level of emission reduction required by the rules. This report will therefore review the proposed BSER and alternative methods of complying with the presumptively approvable standards of performance. It will also discuss some of the flexibility mechanisms permitted under the proposed rules. In addition to the technologies that form the basis of the proposed BSER and the presumptive standards of performance that are proposed, there are additional technical approaches available to individual facilities for complying with the requirements of the proposed rule.

The additional technical approaches beyond deployment of the BSER that might be utilized include:

- Use of carbon capture and storage (CCS) at capture efficiencies greater than assumed as BSER in the proposed rule.
- Fuel switching to lower-emitting fuels. This might include cofiring natural gas or low-GHG hydrogen at higher rates than proposed in the rule, blending low-GHG hydrogen in gas pipelines, firing higher-rank coals or drying low-rank coals, or potentially cofiring other fuels that are demonstrated to be lower-carbon-intensity through robust lifecycle analysis.
- Using efficiency improvements to reduce the $CO_2$ emission rate to be closer to the presumptively approvable standard of performance.
- Utilization of batteries or other storage technologies to move load to base-loaded and well-controlled units.
- Integrating renewables into a fossil-fuel-fired power plant in the form of a hybrid plant, including solar thermal feedwater heaters, solar thermal steam generators, integration of geothermal energy with fossil-fuel-fired power plants, or use of renewable energy to supply plant service or parasitic loads.
- Or, combinations of the above approaches.

As this report demonstrates, a wide range of technology options are available for individual facilities to comply with the requirements of the proposed rule that are in addition to EPA's identified BSER. Furthermore, the proposed rules provide options for compliance flexibility so that facility owners can make the most cost-effective use of these methods.

## II. Background

This report will examine the approaches for complying with EPA's May 2023 proposed GHG standards for fossil-fuel-fired EGUs.[1] In this section the report will review EPA's proposed BSERs and the flexibility mechanisms that are available in the proposed rules. Section III of this report will describe some of the technical approaches that might be utilized to comply with the rules that take advantage of the flexibility mechanisms of the rules. Technical innovation, and its role in facilitating compliance flexibility, will also be examined. The report will discuss emission-reduction measures that could help facilities comply with standards in the form of lb $CO_2$/MWh—without deploying CCS or high levels of hydrogen cofiring at every unit. This report will explore:

1. the numerous compliance options that are available to individual facilities under the proposed Clean Air Act Section 111 GHG rules, and
2. how one might expect those compliance options to expand and multiply given experience with past regulations.

### A. BSERs in the proposed rules

EPA determined BSER for certain fossil generating subcategories:

- New and reconstructed fossil-fuel-fired combustion turbines
- Existing fossil-fuel-fired steam generating units
- Existing fossil-fuel-fired combustion turbines

Within each generating subcategory, EPA established nested subcategories based upon the facility's size, operating characteristics, or, in the case of existing coal steam units, operating horizon. EPA determines the BSER by reviewing available technologies and considering statutorily enumerated factors. Application of the BSER to each subcategory results in a presumptively approvable standard of performance, measured in terms of lb $CO_2$/MWh or reduction from a baseline lb $CO_2$/MWh. Meeting the established standard of performance will enable the facility to comply with the rule, even if the technology representing the BSER for that subcategory is not the technology used for compliance at the facility. The following sections describe the BSER and presumptively approvable standards of performance for each of the various generating subcategories.

#### 1. BSERs for new and reconstructed fossil-fuel-fired combustion turbines

EPA's proposed standards of performance for GHG emissions from new and reconstructed fossil-fuel-fired combustion turbines breaks units into the following subcategories:

- Low Load Combustion Turbines – Capacity factor less than 20 percent

[1] 88 Fed. Reg. 33,240 (May 23, 2023).

- Intermediate Load Combustion Turbines – Capacity factor greater than 20 percent and a source-specific upper bound based upon efficiency
- Base load combustion turbines – Capacity factor greater than a source-specific upper bound based upon efficiency

For the low load subcategory, EPA is proposing that the BSER is the use of lower emitting fuels (e.g., natural gas and distillate oil) with standards of performance ranging from 120 lb $CO_2$/MMBtu to 160 lb $CO_2$/MMBtu, depending on the type of fuel combusted.

For the intermediate load and base load subcategories, EPA is proposing an approach in which the BSER has multiple phases: (1) highly efficient generation; and (2) depending on the subcategory, use of CCS or cofiring low-GHG hydrogen.

For the intermediate load subcategory, EPA is proposing that the BSER includes highly efficient simple cycle combustion turbine technology with an associated first phase standard of 1,150 lb $CO_2$/MWh-gross. For the base load subcategory, EPA is proposing that the BSER includes highly efficient combined cycle technology with an associated first phase standard of 770 lb $CO_2$/MWh- gross for larger combustion turbine EGUs with a base load rating of 2,000 MMBtu/h or more. For smaller base load combustion turbines (with a base load rating of less than 2,000 MMBtu/h), the proposed associated standard would range from 770 to 900 lb $CO_2$/MWh-gross depending on the specific base load rating of the combustion turbine.

Affected sources in the intermediate load and base load subcategories must also meet the second and in some cases third and more stringent phases of the standard of performance, which are based on the continued application of the first component of the BSER and the application of the second and in some cases third component of the BSER. For intermediate load units, EPA is proposing as the second component of BSER the cofiring of 30 percent by volume low-GHG hydrogen by 2032. For base load units, EPA is proposing two pathways as potential BSER: (1) the use of CCS to achieve a 90 percent capture of GHG emissions by 2035; and (2) the cofiring of 30 percent by volume low-GHG hydrogen by 2032, and ramping up to 96 percent by volume low-GHG hydrogen by 2038.[2]

The subcategories, BSERs, and standards are shown in Tables 1-4.

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[2] *Id.* at 33,244.

## Table 1. Proposed BSER for combustion turbine EGUs[3]

| Subcategory | Fuel | 1st Component BSER | 2nd Component BSER | 3rd Component BSER |
|---|---|---|---|---|
| Low Load* | All Fuels | Lower emitting fuels | N/A | N/A |
| Intermediate Load | All Fuels | Highly Efficient Generation | 30 percent (by volume) Low-GHG Hydrogen Co-firing by 2032. | N/A |
| Base Load | Sources adopting the CCS pathway. | Highly Efficient Generation | 90 percent CCS by 2035 | N/A |
| | Sources adopting the low-GHG hydrogen co-firing pathway. | | 30 percent (by volume) Low-GHG Hydrogen Co-firing by 2032. | 96 percent (by volume) Low-GHG Hydrogen Co-firing by 2038 |

* The low load subcategory has a single-component BSER consisting of fuels that emit lower GHG emissions.

## Table 2. Proposed sales thresholds for subcategories of combustion turbine EGUs[4]

| Subcategory | Electric sales threshold (percent of potential electric sales) |
|---|---|
| Low Load | ≤20 percent. |
| Intermediate Load | >20 percent and ≤site-specific value determined based on the design efficiency of the affected facility.<br>• Between ~ 33 to 40 percent for simple cycle combustion turbines.<br>• Between ~ 45 to 55 percent for combined cycle combustion turbines. |
| Base Load | >Site-specific value determined based on the design efficiency of the affected facility.<br>• Between ~ 33 to 40 percent for simple cycle combustion turbines.<br>• Between ~ 45 to 55 percent for combined cycle combustion turbines. |

## Table 3. Phase 2 standards of performance[5]

| Subcategory | BSER | Standard of performance |
|---|---|---|
| Low load | Lower emitting fuels | 120–160 lb $CO_2$/MMBtu. |
| Intermediate load | Highly efficient simple cycle technology coupled with co-firing 30 percent (by volume) low-GHG hydrogen. | 1,000 lb $CO_2$/MWh-gross. |
| Base load adopting the CCS pathway | Highly efficient combined cycle technology coupled with 90 percent CCS. | 90 lb $CO_2$/MWh-gross. |
| Base load adopting the low-GHG hydrogen co-firing pathway. | Highly efficient combined cycle technology coupled with co-firing 30 percent (by volume) low-GHG hydrogen. | 680 lb $CO_2$/MWh-gross. |

## Table 4. Phase 3 standards of performance[6]

| Subcategory | BSER | Standard of performance |
|---|---|---|
| Base load electing to implement early GHG reductions. | Highly efficient combined cycle technology coupled with co-firing 89 percent (by heat input) low-GHG hydrogen. | 90 lb $CO_2$/MWh-gross. |

[3] *Id.* at 33,284.
[4] *Id.* at 33,322.
[5] *Id.* at 33,325.
[6] *Id.*

## 2. BSERs for existing fossil-fuel-fired steam generating units

EPA's proposed emission guidelines for GHG emissions from existing coal-fired steam electric generating units break units into the following subcategories based upon the unit's operating horizon and capacity factor:

- Long-term operating units – Those that are expected to operate into year 2040 or beyond.
- Medium-term operating units – Those that have a federally-enforceable commitment to retire during the years 2032-2039.
- Near-term operating units – Those that have a federally-enforceable commitment to retire prior to January 1, 2035 as well as to adopt an annual capacity factor limit of 20 percent.
- Imminent-term operating units – Those that have a federally-enforceable commitment to retire prior to January 1, 2032.

EPA proposed that the BSERs for these subcategories would be, respectively:

- for long-term operating units, CCS at 90% capture of $CO_2$;
- for medium-term operating units, cofiring with 40% natural gas on a heat-input basis;
- for near-term or imminent-term operating units, routine methods of operation and maintenance with an associated degree of emission limitation.

EPA is proposing a compliance date of January 1, 2030, for affected coal-fired steam generating units.[7] BSERs for affected coal-fired EGUs are described in more detail in Table 5.

[7] *Id.* at 33,371.

### Table 5. Summary of proposed BSER, subcategories, and degrees of emission limitation for affected coal-fired EGUs[8]

| Affected EGUs | Subcategory definition | BSER | Degree of emission limitation | Presumptively approvable standard of performance[561] | Ranges in values on which the EPA is soliciting comment |
|---|---|---|---|---|---|
| Long-term existing coal-fired steam generating units. | Coal-fired steam generating units that have not elected to commit to permanently cease operations by January 1, 2040. | CCS with 90 percent capture of $CO_2$. | 88.4 percent reduction in emission rate (lb $CO_2$/MWh-gross). | 88.4 percent reduction in annual emission rate (lb $CO_2$/MWh-gross) from the unit-specific baseline. | The achievable capture rate from 90 to 95 percent or greater and the achievable degree of emission limitation defined by a reduction in emission rate from 75 to 90 percent. |
| Medium-term existing coal-fired steam generating units. | Coal-fired steam generating units that have elected to commit to permanently cease operations after December 31, 2031, and before January 1, 2040, and that are not near-term units. | Natural gas co-firing at 40 percent of the heat input to the unit. | A 16 percent reduction in emission rate (lb $CO_2$/MWh-gross). | A 16 percent reduction in annual emission rate (lb $CO_2$/MWh-gross) from the unit-specific baseline. | The percent of natural gas co-firing from 30 to 50 percent and the degree of emission limitation from 12 to 20 percent. |
| Near-term existing coal-fired steam generating units. | Coal-fired steam generating units that have elected to commit to permanently cease operations after December 31, 2031, and before January 1, 2035, and commit to adopt an annual capacity factor limit of 20 percent. | Routine methods of operation. | No increase in emission rate (lb $CO_2$/MWh-gross). | An emission rate limit (lb $CO_2$/MWh-gross) defined by the unit-specific baseline. | The presumptive standard: 0 to 2 standard deviations in annual emission rate above or 0 to 10 percent above the unit-specific baseline. |
| Imminent-term existing coal-fired steam generating units. | Coal-fired steam generating units that have elected to commit to permanently cease operations before January 1, 2032. | Routine methods of operation. | No increase in emission rate (lb $CO_2$/MWh-gross). | An emission rate limit (lb $CO_2$/MWh-gross) defined by the unit-specific baseline. | The presumptive standard: 0 to 2 standard deviations in annual emission rate above or 0 to 10 percent above the unit-specific base- |

EPA has also proposed BSERs for gas and oil-fired steam EGUs, as shown in Table 6. The approaches amount essentially to best practices and there are presumptively approvable emission rates.

[8] *Id.* at 33,359-60.

**Table 6. Summary of proposed BSERs, subcategories, and degrees of emission limitation for affected gas and oil-fired steam EGUs**[9]

| Affected EGUs | Subcategory definition | BSER | Degree of emission limitation | Presumptively approvable standard of performance[561] | Ranges in values on which the EPA is soliciting comment |
|---|---|---|---|---|---|
| Base load continental existing oil-fired steam generating units. | Oil-fired steam generating units with an annual capacity factor greater than or equal to 45 percent. | Routine methods of operation and maintenance. | No increase in emission rate (lb $CO_2$/MWh-gross). | An annual emission rate limit of 1,300 lb $CO_2$/MWh-gross. | The threshold between intermediate and base load from 40 to 50 percent annual capacity factor; the degree of emission limitation from 1,250 lb $CO_2$/MWh-gross to 1,800 lb $CO_2$/MWh-gross. |
| Intermediate load continental existing oil-fired steam generating units. | Oil-fired steam generating units with an annual capacity factor greater than or equal to 8 percent and less than 45 percent. | Routine methods of operation and maintenance. | No increase in emission rate (lb $CO_2$/MWh-gross). | An annual emission rate limit of 1,500 lb $CO_2$/MWh-gross. | The degree of emission limitation from 1,400 lb $CO_2$/MWh-gross to 2,000 lb $CO_2$/MWh-gross. |
| Low load (continental and non-continental) existing oil-fired steam generating units. | Oil-fired steam generating units with an annual capacity factor less than 8 percent. | None proposed .............. | .......................................... | .......................................... | The threshold between low and intermediate load from 5 to 20 percent annual capacity factor. |
| Intermediate and base load non-continental existing oil-fired steam generating units. | Non-continental oil-fired steam generating units with an annual capacity factor greater than or equal to 8 percent. | Routine methods of operation and maintenance. | No increase in emission rate (lb $CO_2$/MWh-gross). | An emission rate limit (lb $CO_2$/MWh-gross) defined by the unit-specific baseline. | The presumptive standard: 0 to 2 standard deviations in annual emission rate above or 0 to 10 percent above the unit-specific baseline. |
| Base load existing natural gas-fired steam generating units. | Natural gas-fired steam generating units with an annual capacity factor greater than or equal to 45 percent. | Routine methods of operation and maintenance. | No increase in emission rate (lb $CO_2$/MWh-gross). | An annual emission rate limit of 1,300 lb $CO_2$/MWh-gross. | The threshold between intermediate and base load from 40 to 50 percent annual capacity factor; The acceptable standard from 1,250 lb $CO_2$/MWh-gross to 1,400 lb $CO_2$/MWh-gross. |
| Intermediate load existing natural gas-fired steam generating units. | Natural gas-fired steam generating units with an annual capacity factor greater than or equal to 8 percent and less than 45 percent. | Routine methods of operation and maintenance. | No increase in emission rate (lb $CO_2$/MWh-gross). | An annual emission rate limit of 1,500 lb $CO_2$/MWh-gross. | The acceptable standard from 1,400 lb $CO_2$/MWh-gross to 1,600 lb $CO_2$/MWh-gross. |
| Low load existing natural gas-fired steam generating units. | Natural gas-fired steam generating units with an annual capacity factor less than 8 percent. | None proposed .............. | .......................................... | .......................................... | The threshold between low and intermediate load from 5 to 20 percent annual capacity factor. |

### 3. BSER for existing fossil-fuel-fired stationary combustion turbines

EPA's proposed emission guidelines for GHG emissions from existing fossil-fuel-fired stationary combustion turbines limits applicability based upon the capacity and capacity factor.

Large, over 300 MW turbines with capacity factor in excess of 50 percent, would have similar requirements as new, base load turbines – based on either the use of CCS by 2035 or cofiring of 30 percent (by volume) low-GHG hydrogen by 2032 and cofiring 96 percent low-GHG hydrogen by 2038.[10]

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[9] *Id.* at 33,359-60.
[10] *Id.* at 33,245-46.

## B. Flexibility mechanisms available to states

EPA has a long history of developing rules that have provided flexible means to comply through use of innovative technical approaches and emerging technologies, and this is explored in detail elsewhere.[11] These mechanisms have included: 1) establishing emission rate or percent reduction standards that allow facilities to choose a technology; 2) facility-wide or system-wide averaging; 3) emissions trading; 4) state plans that meet the requirements of one or more rules within the needs of the state, and other approaches.

In addition to establishing the BSER, in the proposed rule there are flexibility provisions, including provisions for trading or emissions averaging. States may develop, submit and, if approved by EPA, implement plans that set standards for existing sources incorporating flexibility provisions provided that the state can demonstrate that standards and compliance mechanisms in its plan are at least as stringent as if EPA's BSER were applied to each source:

> *" . . . while States have the discretion to establish the applicable standards of performance for affected sources in their State plans, the structure and purpose of CAA section 111 require that those plans achieve equivalent stringency as applying the EPA's presumptive standards of performance to each of those sources."*[12]

> *"In sum, consistent with the respective roles of the EPA and States under CAA section 111, States have discretion to establish standards of performance for affected sources in their State plans, and to provide flexibilities for affected sources to use in complying with those standards. However, State plans must demonstrate that they ultimately provide for equivalent stringency as would be achieved if each affected source was achieving the applicable presumptive standard of performance, after accounting for any application of RULOF."*[13]

Under the proposed rules, averaging and emissions trading are expressly permitted to be incorporated into the SIP so long as the state can demonstrate equivalent emission reductions:

> *"The EPA is proposing to allow states to incorporate averaging and emission trading into their State plans, provided that states ensure that use of these compliance flexibilities will result in a level of emission performance by the affected EGUs that is equivalent to each source individually achieving its standard of performance."*[14]

In its proposal, EPA discussed some of the advantages and challenges in implementing a trading program.[15] Some of the challenges result from the different subcategories in the rule; for several subcategories, trading would not be an appropriate compliance mechanism because their

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[11] J. Staudt, Andover Technology Partners, *History of Flexible Compliance with Science-Based and Technology-Based Stationary Source Air Pollution Regulations*, December 18, 2023.

[12] 88 Fed. Reg. at 33,374.

[13] *Id.* at 33,374.

[14] *Id.* at 33,392.

[15] *Id.* at 33,393-94.

BSERs involve routine operations and maintenance that should not be forgone.[16] EPA also discussed rates-based and mass-based emission trading program approaches that potentially could be included in SIPs.[17]

EPA also discussed rate-based averaging as a compliance flexibility mechanism and how states could potentially incorporate rate-based averaging in a way that preserves the stringency of EPA's BSER as well as some considerations related to incorporating averaging in state plans.[18]

Therefore, states can impose on each source the presumptively approvable standard that EPA has identified as reflecting the BSER. Or, states may be able to adopt other standards that they can demonstrate achieve the same level of stringency as if each affected source was achieving the presumptive standard.

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[16] *See id.*
[17] *Id.* at 33,394-6.
[18] *Id.* at 33,396.

## III. Technologies and Compliance Approaches

There are manifold technologies and compliance approaches available to owners and operators of sources subject to the rules that go beyond the BSER that EPA has identified. EPA acknowledges in the proposed rule that technical innovation is an important consideration informing not only its analysis of the BSER, but also the flexibilities available for compliance that could foster further innovation. Per the proposed rule,

> *"The D.C. Circuit has long held that Congress intended for CAA section 111 to create incentives for new technology and therefore that the EPA is required to consider technological innovation as one of the factors in determining the ''best system of emission reduction."*[19]

EPA further states that

> *"[t]he legislative history identifies three different ways that Congress designed CAA section 111 to authorize standards of performance that promote technological improvement: (1) The development of technology that may be treated as the 'best system of emission reduction . . . adequately demonstrated;' under CAA section 111(a)(1); (2) the expanded use of the best demonstrated technology; and (3) the development of emerging technology."*[20]

Thus, Section 111 rules may be designed not only to improve and promote deployment of the BSER, but also to facilitate technological innovation through compliance flexibilities.

As previously noted, EPA will consider state plans that incorporate trading or averaging, provided that the state can demonstrate that standards of performance included therein will collectively be at least as stringent as the presumptively approvable standards that EPA has identified as reflecting the BSER. This is consistent with what EPA has done in other regulations.[21] Furthermore, the proposed rule, while identifying the BSER, also establishes presumptively approvable emission rates that may be achieved by other technical measures, perhaps while taking advantage of flexibility mechanisms permitted under the proposed rule. In light of the fact that the proposed rule provides presumptively approvable emission rates and has flexibility provisions, one would expect to see the available technical measures expand beyond those already identified as BSER. This is particularly useful in opening the opportunity for alternative compliance mechanisms because states and facility owners, understanding their facilities and systems, can devise approaches that achieve the same or more stringent emission reduction objectives at lower costs. For example, the presumptively approvable emission rates provide a quantitative benchmark that may be achieved across multiple affected sources with some sources over-controlling and others under-controlling, with states and facility owners determining the best

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[19] *Id.* at 33,275.
[20] *Id.*
[21] J. Staudt, Andover Technology Partners, *History of Flexible Compliance with Science-Based and Technology-Based Stationary Source Air Pollution Regulations*, December 18, 2023.

combination of measures to achieve the presumptively approvable emission rates for the combination of affected units. Alternative technical measures could include the following:

- Achieving higher $CO_2$ capture rates than BSER
- Switching to lower-emitting fuels
- Efficiency improvements, increasing output or shifting load to lower-emitting units
- Utilization of batteries or other storage technology on fossil-fuel-fired units or plants to manage capacity factor
- Integrated renewables or hybrid energy systems
- Combinations of the above methods
- New measures that are developed in response to the rule

## A. Higher $CO_2$ capture rates than BSER

It may be possible to overcontrol one unit in a multi-unit plant, and under control another, to meet the performance standard. This possibility enables an averaging or trading mechanism. This is what was achieved with programs such as the Title IV Acid Rain Program, the NOx SIP Call, and CAIR/CSAPR, as described by Staudt.[22] Some facilities achieved well below the presumptive levels, while others were above the presumptive levels. This may be possible to comply with this proposed rule as well. For example, 95-99% CCS with plantwide averaging exceeds the capture efficiency identified as BSER and might be performed while other units reduce capacity factors, cofire lower-emitting fuels, and/or capture $CO_2$ at lower rates.

Several pre- and post-combustion solvent-based methods for carbon capture are relatively well developed. In addition to those methods, the Department of Energy (DOE) has identified numerous, developing methods for carbon capture, such as membrane-based methods, cryogenic methods, absorption-based methods with other solvents, and other methods that offer promise as potentially more effective and less expensive methods of control.[23] Some technologies have already been identified as capable of over 90% $CO_2$ capture. For example, Mitsubishi Heavy Industries' and Fluor's processes, which have been commercially deployed, are capable of 95% capture and DOE is examining processes with capture efficiencies up to 99%.[24]

Like other air pollution reduction technologies, absent incentives that would render the technology profitable, CCS would not be expected to be widely deployed without a requirement to control $CO_2$. Capture of $CO_2$ from combustion sources has been under development for decades and has been used to clean natural gas since the 1920s. The first use of $CO_2$ for enhanced oil recovery was in the 1970s. The first use of $CO_2$ for enhanced oil recovery was in the 1970s and

[22] *Id.* at 22-36.

[23] United States Department of Energy National Energy Technology Laboratory, *Compendium of Carbon Capture Technology*, 2022, available at: https://netl.doe.gov/sites/default/files/2022-09/0919-Carbon-Capture-Technology-Compendium-2022.pdf.

[24] *Id.* at 66, 72, 103, 183, 380, 449, 480,

various CCS projects continued to advance in the following decades.[25] Therefore, while CCS is not widely used at this time, there are decades of experience with its development to rely upon when the technology becomes more widely deployed. There are more than 40 commercial CCS facilities in operation at this time, and project developers have announced an additional 50 new facilities to be in operation by 2030.[26]

Increased deployment of CCS could follow a trajectory similar to that of selective catalytic reduction systems (SCR). SCR was deployed on only a handful of coal-fired facilities at the end of 1999 (only 8,167 MW of coal-fired capacity with SCR installed). As demonstrated in Figure 1, in response to EPA's NOx SIP Call rule, by the end of 2004 there would be over ten times as much coal capacity with SCR installed (86,080 MW).[27] A 1998 report showed SCRs on US coal-fired power plants operating with capture efficiencies ranging from 50% to 73%.[28] By 2004, EPA investigators collected data from facility owners on 23 high efficiency SCRs (85% removal or higher) and from owners of two older SCRs that are not designed for high removal efficiencies. According to the facility owners, "SCRs, on average are currently providing between 88% and 89% NOx reduction."[29] Facility owners told EPA investigators regarding SCRs at their facilities, "if necessary, these units could provide, on average, close to 91% NOx reduction on a regular basis," with guaranteed NOx reduction typically around 90%.[30] So, within a six-year period between 1998 and 2004, SCR capture efficiencies for coal EGUs increased dramatically. Also, over that same period, the installed base increased by over a factor of ten. This demonstrates that, with more experience, performance of a technology will improve and emissions rates decrease.

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[25] https://ieaghg.org/docs/General_Docs/Publications/Information_Sheets_for_CCS_2.pdf; U.S. Department of Energy's Carbon Storage Program has been active since 1997, https://netl.doe.gov/carbon-management/carbon-storage.

[26] https://www.iea.org/energy-system/carbon-capture-utilisation-and-storage

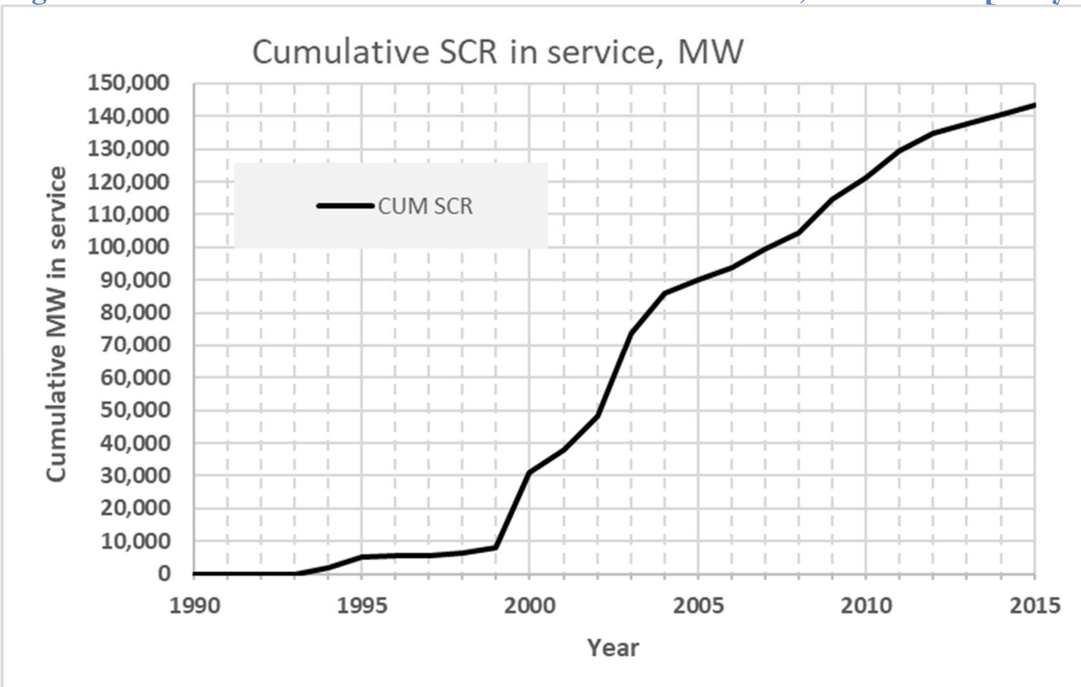
[27] Developed from US EPA's National Electric Energy Data System (NEEDS)

[28] Andover Technology Partners, for Northeast States for Coordinated Air Use Management, *Status Report on NOx: Control Technologies and Cost Effectiveness for Utility Boilers*, June 1998, p. 59.

[29] Staudt, J., et al., "Reliability of Selective Catalytic Reduction (SCR) and Flue Gas Desulfurization (FGD) Systems for High Pollutant Removal Efficiencies on Coal Fired Utility Boilers", *The 2004 MEGA Symposium, Paper # 04-A-56-AWMA,* 30 August - 2 September 2004, Washington, DC, p. 5, notably, as noted in this paper, most facilities operated their SCRs controlling to an emission rate that was attainable at a lower capture efficiency than guaranteed. So, it would not be surprising that typical capture efficiencies were somewhat lower than the guaranteed rate.

[30] *Id*. at 6.

**Figure 1. Cumulative coal-fired EGUs with SCR in service, in MW of capacity**[31]




Experience with wet flue gas desulfurization FGD systems (FGDs) is also instructive. As shown in Figure 2, limestone wet FGD system capture efficiency improved as experience with the technology grew. Typical capture efficiencies grew from around 90% in the 1980s to around 95% in the 1990s to about 98% by 2005 with several facilities designed for 99% $SO_2$ removal. By 2004, facility owners found that their limestone wet FGD systems could provide much higher capture efficiency than they normally operated at or was guaranteed.[32] In a similar manner, it is reasonable to expect that, as utilities begin to deploy CCS, they will find means to improve capture efficiency to well beyond the BSER capture efficiency of 90%. Furthermore, once CCS systems are installed, it is likely that facility owners will find ways to improve capture efficiency of existing systems even further, as occurred with FGD systems.[33]

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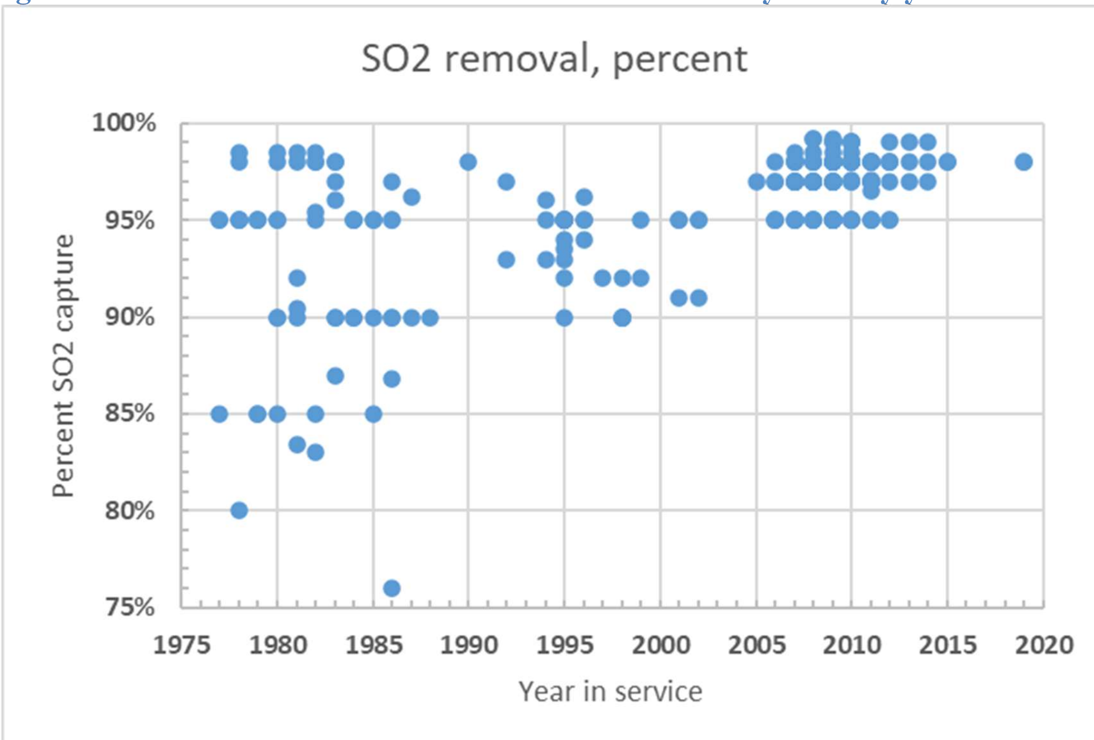
[31] Developed from US EPA's National Electric Energy Data System (NEEDS)
[32] *Id.*
[33] J. Staudt, Andover Technology Partners, *History of Flexible Compliance with Science-Based and Technology-Based Stationary Source Air Pollution Regulations*, December 18, 2023, pp. 34-35.

**Figure 2. $SO_2$ removal efficiencies for limestone WFGD systems by year in service[34]**




## B. Switching to lower-emitting fuels

The proposed emission limitations for long-term coal-fired units represent a reduction from a baseline emission rate, and are based upon a particular technology (e.g., CCS). Another option is fuel switching, which might mean a complete change of fuel from coal to natural gas, or incorporation of other, lower-emitting fuels into the fuel mix. The following section will examine a number of possible variations of changes in fuel that might be utilized alone or in combination with other methods to meet the requirements of the proposed rule.

### 1. Cofiring natural gas at greater rates than for the presumed limits and use of plantwide averaging

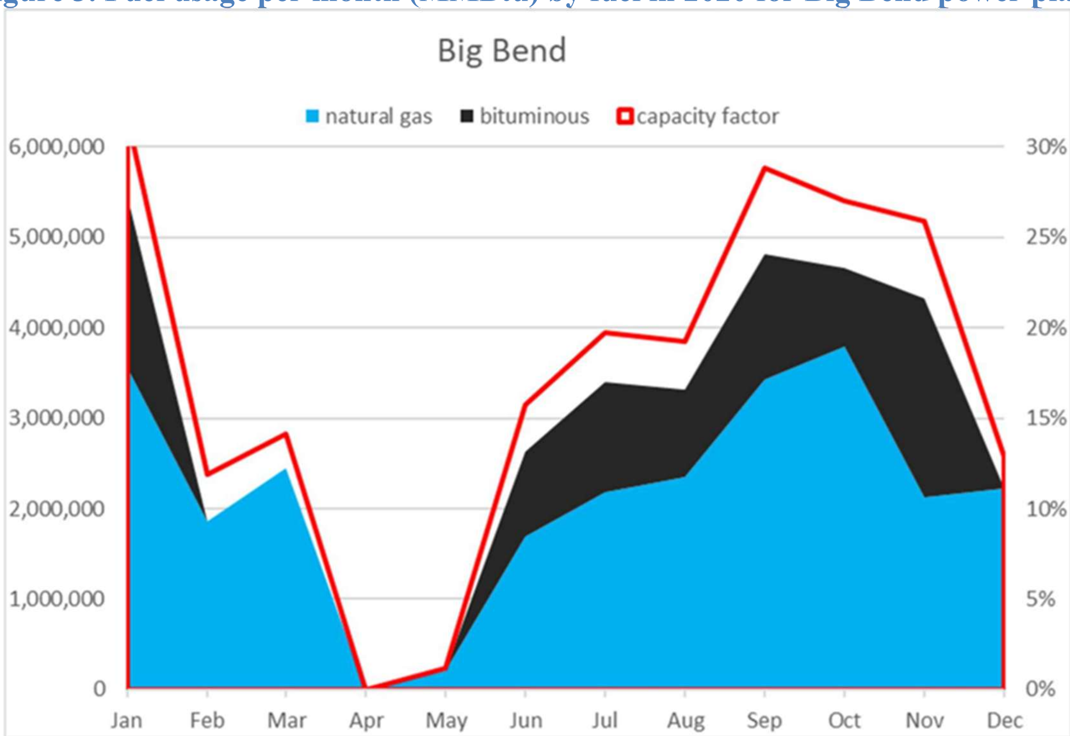
The proposed BSER for medium-term existing coal units is 40% natural gas cofiring at that unit and the presumptively approvable standard is a reduction in emission rate of 16%. It is possible to increase cofiring beyond that level. In combination with averaging, that might allow increased use of natural gas at one unit to help bring multiple units into compliance. Staudt described several case studies where cofiring was used.[35] For example, at the Big Bend power plant in Florida, in 2020 73% of the fuel input for the plant was natural gas—well over the 40%

[34] Developed from EIA Form 860 data

[35] Staudt, J., Andover Technology Partners, *Natural Gas Cofiring for Coal-Fired Utility Boilers*, for Center for Applied Environmental Law and Policy (CAELP), February 12, 2022.

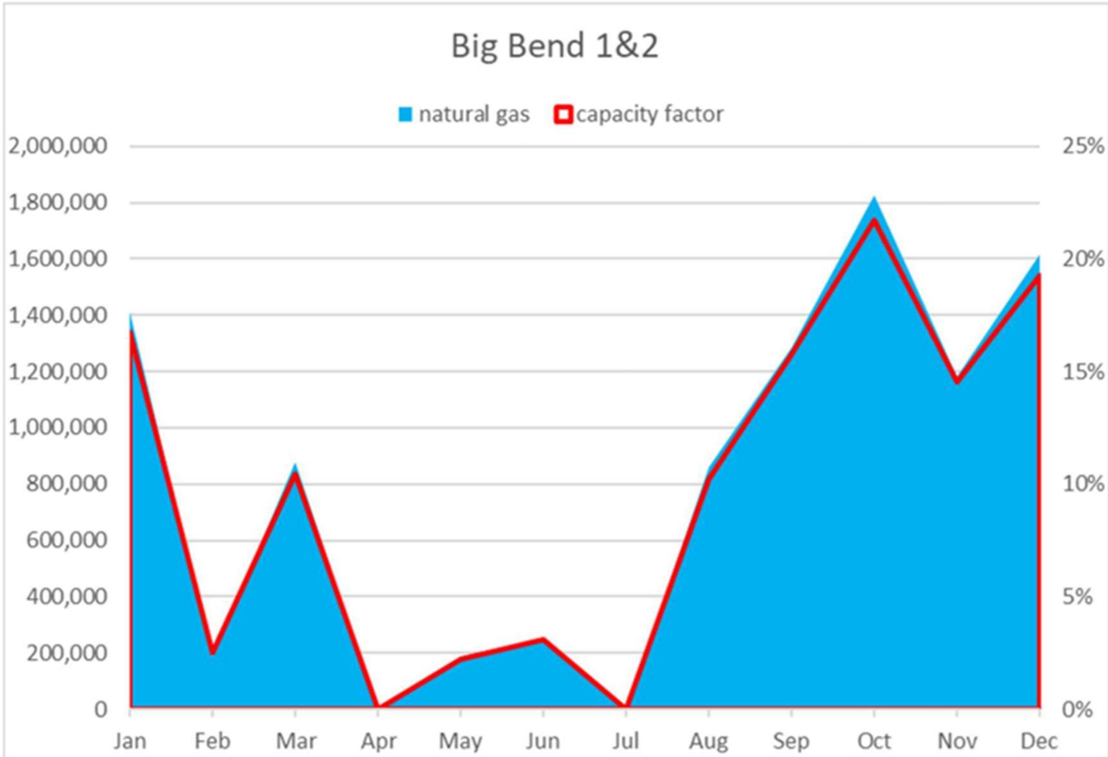
of natural gas heat input involved in the proposed BSER for medium-term coal-fired units.[36] Figure 3 shows fuel use by month (in MMBtu) for the two fuels used at the Big Bend plant, natural gas and bituminous coal. It also shows the capacity factor (%) of the facility. As shown in Figure 4, Big Bend units 1 & 2 operated completely on natural gas that year, while the entire plant fired more than 40% natural gas. The result was a plant natural gas usage that equated to about 73% of heat input. Therefore, at Big Bend the use of natural gas at units 1 & 2 brought the entire plant to a point of over 40% heat input by natural gas. If Big Bend was in the medium-term subcategory, this level of cofiring might be expected to bring the entire facility into compliance if averaging across all units was used. And, since well over 40% cofiring was being performed, if averaged with other medium-term coal units, it might be able to bring the combined facilities into compliance.

**Figure 3. Fuel usage per month (MMBtu) by fuel in 2020 for Big Bend power plant**




[36] *Id.* at 24.

**Figure 4. Fuel usage per month (MMBtu) by fuel and capacity factor in 2020 for Big Bend Units 1 & 2**

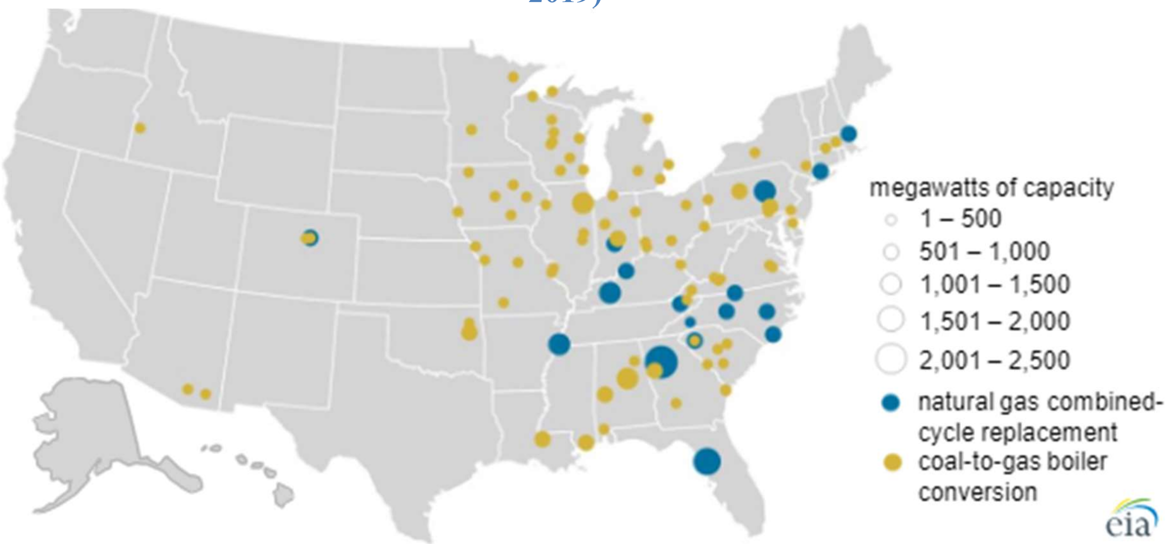



## 2. Converting a coal unit or facility to total natural gas firing

Converting a coal steam unit to a natural gas steam unit will enable the facility to comply with that applicable limit (based upon operational characteristics).

Repowering existing coal units with natural gas combustion turbines is a more extensive option, and this is an approach that some facility owners have chosen. In fact, the Energy Information Administration (EIA) determined that from 2011 to 2019 over 100 coal plants were converted to natural gas, either as gas steam units or to natural gas combined cycle (NGCC) facilities, as shown Figure 5. As shown, although the number of units that EIA reported were converted to natural gas fired boilers was larger than those converted to NGCC, the largest conversions were to NGCC. The units that remained steam units tended to be smaller, less competitive facilities that likely did not justify the investment for NGCC conversion because they would be used as peaking units. Longer term, gas steam facilities where demand is increasing might convert to NGCC in the future.

**Figure 5. U.S. Coal to natural gas plant conversion by conversion type and capacity (2011-2019)[37]**




### 3. Blending low-GHG hydrogen in gas pipelines serving either gas or coal units

Low-GHG hydrogen, as defined by EPA in the proposal, is hydrogen produced "through a process that results in a GHG emission rate of less than 0.45 kilograms of $CO_2$ equivalent per kilogram of hydrogen (kg $CO_2e$/kg $H_2$) on a well-to-gate basis."[38] The most likely technology to reach this threshold is hydrogen produced from electrolysis using zero-carbon electricity such as wind, solar, hydro, geothermal or nuclear. Combustion of low-GHG hydrogen emits no $CO_2$, which is an advantage versus other carbon-bearing fuels. Gas and coal units may burn low-GHG hydrogen, and it is an option as BSER for existing and new base load turbines and one component of the BSER for new intermediate turbines.

Hydrogen can be produced locally alongside the co-firing unit, or transported from third-party locations. An example of co-located production is shown in Figure 6 below. Here, zero-carbon energy is used to power a Silyzer 300 electrolysis plant and the produced hydrogen can be co-fired with natural gas to power the gas turbine.

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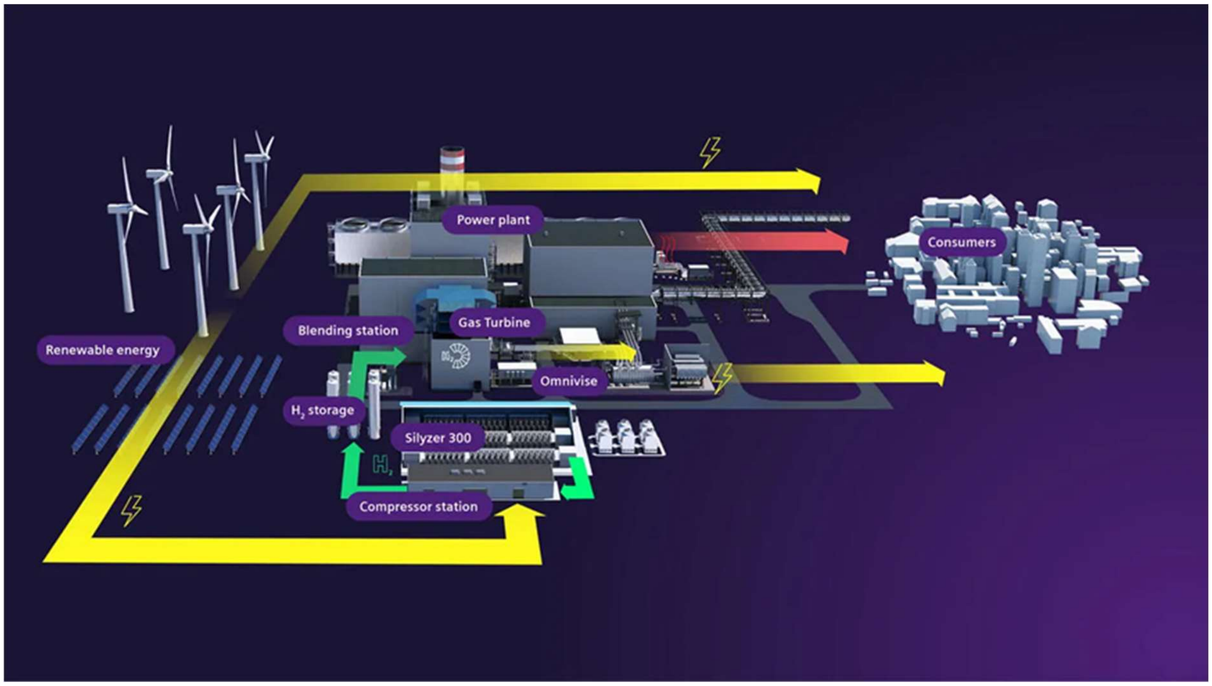
[37] https://www.eia.gov/todayinenergy/detail.php?id=44636
[38] 88 Fed. Reg. at 33,304.

**Figure 6. Siemens Energy New Build Hydrogen Power Plant.**[39]




There are multiple ways to transport hydrogen that is produced offsite from the power plant. Dedicated hydrogen pipelines would be the best option for high-volume and long-distance transport, but hydrogen may also be transported via gas or liquid trucks. Hydrogen may also be blended into existing natural gas pipelines that serve multiple customers. Figure 7 shows how hydrogen could be introduced and blended into transmission or distribution pipelines and supplied as a blended fuel for assorted industrial uses, including electricity generation. Hydrogen can also be utilized on its own in various applications besides power generation such as heavy-duty transportation, chemical production, and high temperature process heating. Figure 8 shows the relationship between hydrogen production, natural gas infrastructure and electricity infrastructure. Electricity is used to generate hydrogen, which can then be sent into natural gas infrastructure or used in other applications, including generation of electricity. The figure also shows various end uses for hydrogen that include assorted chemical and fuel production, metals production and transportation.

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[39] https://www.siemens-energy.com/global/en/home/products-services/product/hydrogen-power-plants.html; Silyzer 300 is the electrolysis unit; Omnivise is the overall control system that optimizes supply and demand by integrating all the required plant components.

**Figure 7. Hydrogen production and supply to natural gas pipelines**
**The hydrogen production and supply to gas[40]**

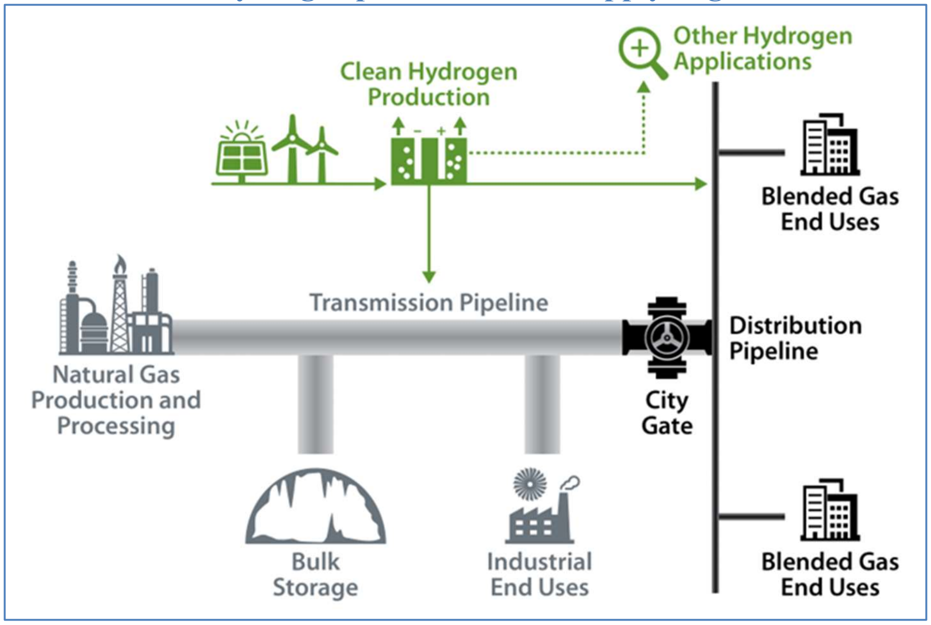
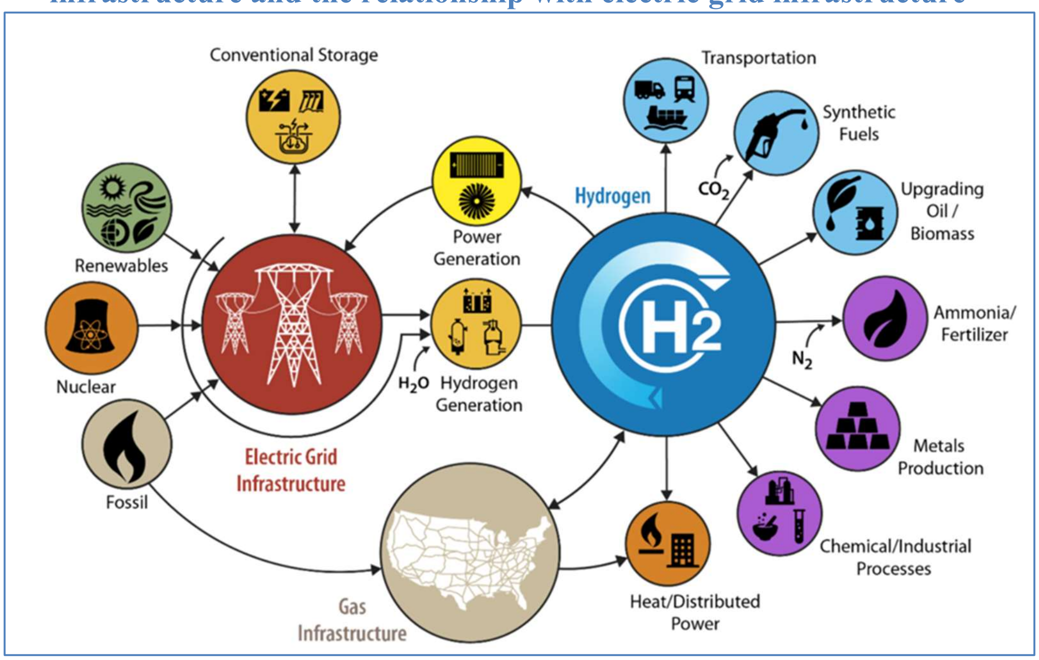



**Figure 8. Hydrogen production, supply to various uses, including natural gas transmission infrastructure and the relationship with electric grid infrastructure[41]**




[40] https://www.energy.gov/eere/fuelcells/hyblend-opportunities-hydrogen-blending-natural-gas-pipelines

[41] National Renewable Energy Laboratory, *Hydrogen Blending into Natural Gas Pipeline Infrastructure: Review of the State of Technology,* NREL/TP-5400-81704, October 2022, p. 13. Only hydrogen produced using renewables or nuclear energy could be considered low-GHG hydrogen for purposes of complying with the proposed rules.

The United States Department of Energy's National Renewable Energy Laboratory (NREL) has examined various considerations for blending hydrogen into natural gas pipelines. These include identifying end-use applications for blended hydrogen, assessing the integrity of pipeline components after blending, determining changes to pipeline failure mechanisms and other factors.[42] They also examined impacts on network design, performed technoeconomic modeling and reviewed the blending demonstration programs that have been deployed. Some of the conclusions from this analysis are listed below:

- Differences in chemical/physical properties between natural gas and hydrogen may impact some use applications and transportation/distribution. Combustion properties could impact some end-use applications and the low molecular weight of hydrogen demands higher volumetric flowrates for a given energy demand, impacting transport and distribution.
- With regards to pipeline failure mechanisms, it was determined that, "hydrogen has a pronounced effect on fatigue and fracture properties, but the influence of partial pressure is relatively modest; thus it seems unlikely that the percentage of hydrogen in the system will be a determining factor on the structural integrity of the line pipe."[43] In effect, while fatigue crack growth in steel pipelines is higher when hydrogen is present versus air or hydrocarbons, neither the level of hydrogen concentration nor the steel type appears to make a difference.
- System and techno-economic studies tend to suggest that the degree of hydrogen that can be blended into a pipeline is case-specific.[44] But, there is experience in the United States with transporting hydrogen using pipelines originally configured for hydrocarbons and achieving successful operation with some modifications.[45]

In summary, the DOE studies showed that some modifications or changes in operation would be necessary to accommodate hydrogen in natural gas pipelines; but, experience has shown that this can be done successfully.

As a fuel, hydrogen may be burned in boilers and in gas turbines. Hydrogen has a lower heat input per unit of volume than methane (gas) and a higher flame speed and flame temperature, which impact how it can be burned. As a result, higher volumetric flows of hydrogen are needed for the same thermal input. The higher flame temperature might increase NOx emissions. For new intermediate-load gas turbines the proposed second component of the BSER is 30% cofiring

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[42] National Renewable Energy Laboratory, *Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues,* NREL/TP-5600-51995 March 2013.

National Renewable Energy Laboratory, *Hydrogen Blending into Natural Gas Pipeline Infrastructure: Review of the State of Technology,* NREL/TP-5400-81704, October 2022.

[43] National Renewable Energy Laboratory, *Hydrogen Blending into Natural Gas Pipeline Infrastructure: Review of the State of Technology,* NREL/TP-5400-81704, October 2022, p. 13.

[44] *Id.* at 36.

[45] *Id.* at 37.

of low-GHG hydrogen with a standard of performance of 1000 lb/MWh. General Electric (GE) gas turbines currently can fire up to 100% hydrogen in B/E class, and F class turbines. GE's HA class turbines can currently fire up to 50% hydrogen and its aeroderivative turbines can fire up to 85% hydrogen. GE is planning to increase the firing capabilities for both these turbines to 100%.[46]

Siemens Energy has developed a hydrogen power plant that includes a hydrogen-fired gas turbine (e.g. SGT5-9000HL, SGT-800, or SGT-400), electrolyzers with hydrogen compression and storage, and a fleet management system to integrate all components including renewable energy sources feeding electricity into the electrolyzer.[47] Therefore, it is apparent that gas turbine suppliers are manufacturing turbines that are capable of greater than 30% cofiring of hydrogen with natural gas by volume, which means that intermediate-load turbines may be run at higher levels of hydrogen cofiring, running at lower emission rates than the 1000 lb/MWh proposed standard of performance. Under an averaging or trading program, that might allow other intermediate units to run at lower levels of hydrogen cofiring.

In the case of existing coal units in the medium-term subcategory, cofiring low-GHG hydrogen would result in lower $CO_2$ emissions (in terms of lbs $CO_2$ emitted at the stack per MWh) than cofiring the same heat input of natural gas. It would therefore be possible to meet the requirements of the proposed BSER of 40% natural gas cofiring with a lower level of cofiring that included low-GHG hydrogen. The presumptively approvable standard of performance associated with 40% natural gas cofiring is a 16% reduction in the $CO_2$ emission rate. Therefore, the use of low-GHG hydrogen at a rate of 16% of heat input should roughly result in an equivalent emission reduction as the presumptive standard of performance. Cofiring low-GHG hydrogen as opposed to natural gas would entail possible changes to burners and changes to the supply system because the volume of natural gas per unit of heat input is greater for hydrogen. It may entail modifications to address NOx emissions, since hydrogen has higher flame temperature and may result in a higher NOx emission rate.

Cofiring low-GHG hydrogen would also reduce the level of natural gas cofiring that would be needed to meet the presumptive standard of performance. Cofiring 40% of a blended hydrogen/natural-gas fuel would result in a greater than 16% reduction in $CO_2$ emission rate, which would be more effective from an emissions standpoint than the presumptive approved standard of performance associated with 40% cofiring natural gas. With a trading or averaging program, this might be used to permit other medium-term coal units to cofire natural gas to lower levels.

### 4. Burning higher-rank coal or drying of low-rank coal

Higher-rank coal (except anthracite) will generally emit lower $CO_2$ emissions per unit of heat input than lower-rank coals in large part due to the lower moisture content of the higher-rank

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[46] https://www.ge.com/gas-power/future-of-energy/hydrogen-fueled-gas-turbines
[47] https://www.siemens-energy.com/global/en/home/products-services/product/hydrogen-power-plants.html

coal. According to the Energy Information Administration, "[i]n pounds of carbon dioxide per million Btu, U.S. average factors are 227.4 for anthracite, 216.3 for lignite, 211.9 for subbituminous coal, and 205.3 for bituminous coal."[48] Therefore, except for anthracite,[49] changing to higher-rank coals can reduce the $CO_2$ emission rate of a facility. Lower moisture content also offers the advantage of lower parasitic losses, which will improve heat rate and lower $CO_2$ emission rate on a lb/MWhr basis. Many facilities changed from higher-rank eastern or Illinois Basin bituminous coals to subbituminous Powder River Basin (PRB) coals to reduce $SO_2$ emissions in response to the Title IV requirements and other $SO_2$ control requirements. Changing back is clearly possible from a technical perspective, but PRB coal tends to have lower sulfur and nitrogen content than bituminous coal. Therefore, changing to higher-rank coal might increase $SO_2$ emissions, depending upon whether or not there is a form of $SO_2$ capture technology installed at the facility that can offset the increased $SO_2$ emissions from firing bituminous coal. NOx emissions will also be impacted, but facilities with post-combustion NOx controls can eliminate any potential NOx emissions increase from switching coals.

Because lignite is such low-quality coal, lignite-fired facilities are typically mine-mouth plants that were initially built to only burn the coal from the co-located lignite mine. However, some facilities have made modifications to burn both lignite and subbituminous coal. In Texas, the Limestone, Big Brown, Martin Lake, and Monticello plants (some of them now retired) have burned both lignite and PRB coal. In North Dakota, both lignite and subbituminous coal have been burned at the Leland Olds plant.[50] Conversion of a lignite coal plant to another coal might require addition of coal transportation infrastructure if it does not already exist (i.e., a rail spur). Other fuel handling changes would be modest because going from lower-rank coal to higher-rank coal is much easier due to the lower amount of fuel that must be handled. There are also other advantages because flue gas volume flowrate would be lower due to the lower moisture content of the higher-rank coal. Lower flue gas flowrate will reduce parasitic loads and will permit higher emission reductions from pollution control equipment. Conversion from lignite coal to subbituminous coal is clearly possible. Since lignite coal has much higher Hg content than either subbituminous or bituminous coal, conversion to other coals would reduce Hg emissions. Conversion to bituminous coal is also technically possible, but that might be less economically attractive due to the generally higher cost of eastern coal.

For facilities with low-rank coals, another option is coal drying. Coal drying removes some of the moisture that reduces the heat available from coal, which will reduce the $CO_2$ emissions per unit of electrical output. The DryFining technology is an example of a coal drying technology that

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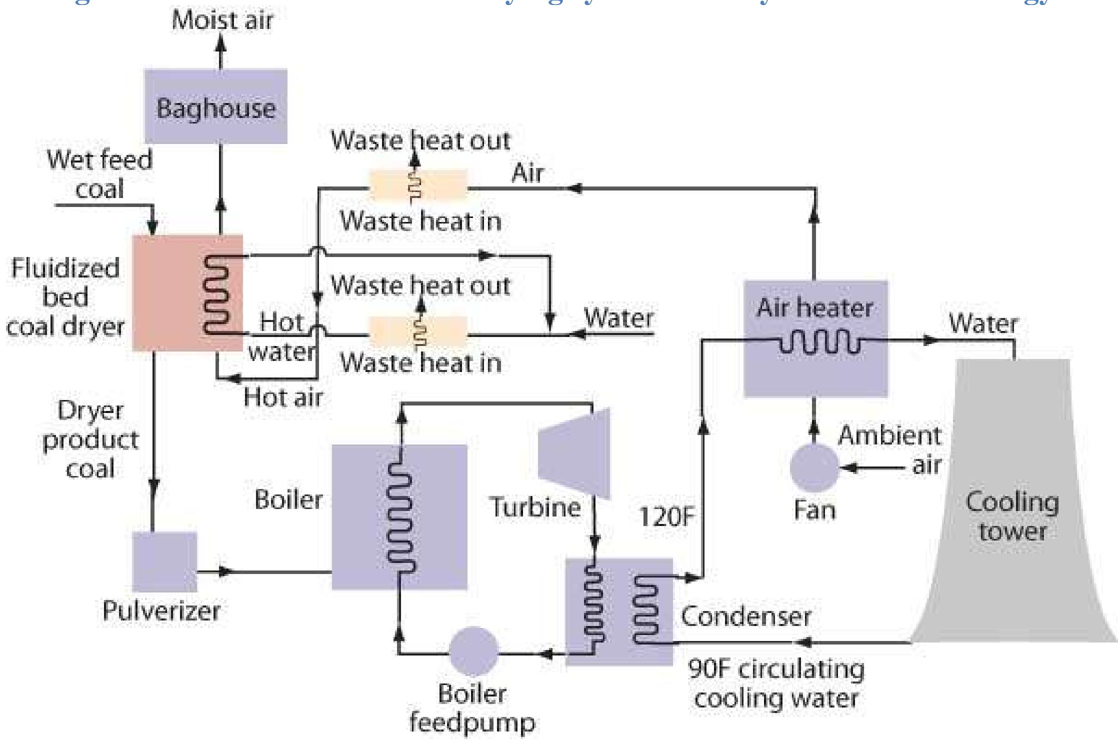
[48] https://www.eia.gov/coal/production/quarterly/co2_article/co2.html

[49] Anthracite is very low moisture, which helps its heating value, but it has a much higher carbon content than other coals and therefore produces more $CO_2$ per unit of heating value. Anthracite is not used to any significant degree in US coal-fired EGUs.

[50] EIA Form 923 data from 2012 shows both lignite and subbituminous coals used at these plants.

was developed by Great River Energy and implemented at the Coal Creek Station in North Dakota. A schematic is shown in Figure 9. The technology uses condensate waste heat to heat and remove moisture from the lignite coal in a fluidized bed coal dryer. By drying the coal with the use of boiler exhaust heat, available heat of the coal was increased from 6,200 Btu/lb to 7,100 Btu/lb, which reduced the coal used by 14%. At the same time, $SO_2$ and Hg emissions were reduced by over 40%, NOx was reduced by over 20%, and $CO_2$ was reduced by 4%.[51]

**Figure 9. Schematic of the coal drying system used by Great River Energy[52]**




## C. Efficiency improvements / increased electricity output / shifting to lower-emitting units

Efficiency improvements (or heat rate improvements, HRI) may also be used to make progress towards the presumptively approvable standards of performance. Efficiency improvements will reduce the degree to which other means might be necessary for complying with presumptive performance standards. In the proposal, EPA identified concerns about "rebound" effects of HRI, or increases in total $CO_2$ emissions, that can result from increased dispatch of coal

[51] https://www.energy.gov/fecm/articles/innovative-drying-technology-extracts-more-energy-high-moisture-coal; https://www.icinorthdakota.com/projects/project/dryfining-project

[52] "Lignite Drying: New Coal-Drying Technology Promises Higher Efficiency Plus Lower Costs and Emissions", *Power Magazine*, July 1, 2007, https://www.powermag.com/lignite-drying-new-coal-drying-technology-promises-higher-efficiency-plus-lower-costs-and-emissions/.

units versus other units due to the improved variable operating costs.[53] This would need to be addressed in any plan.

Other options are improvements in output that result from some HRI measures, such as from turbine inlet cooling, spray intercooling or improvements in steam turbine flowpath. Shifting load away from less efficient (or higher-emitting) units to more efficient (or lower-emitting) units is an approach that is available to facility owners when state plans permit averaging or trading.

### 1. Heat rate improvements on coal units, potentially including upgrades to other pollution controls that would reduce co-pollutant emissions

Coal plant efficiency improvements are possible through a number of means. In 2015, EPA determined that 4.3% HRI was possible on average for units in the Eastern Interconnect, 2.1% HRI was possible in the Western Interconnection, and 2.3% HRI was possible in the Texas Interconnection.[54]

Earlier, Sargent & Lundy conducted a study that reviewed numerous methods to reduce heat rate, and this was updated in 2023.[55] And the United States Department of Energy (DOE) evaluated four approaches for improving efficiency in coal plants that included coal pulverizer improvement, condenser improvement, steam turbine upgrade, and solar-assisted feedwater heaters.[56] The first three technologies were identified by DOE as "off the shelf" technologies, or technologies that are currently well proven and costs well understood. The potential impacts of the three off-the-shelf technologies were evaluated for two model plants, and the results are shown in Table 7. As shown, depending upon the circumstances for the existing plant, the reduction in $CO_2$ emissions could be between 1.7% and 6.9%.

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[53] 88 Fed. Reg. at 33,357.
[54] *Id.* at 33,356-57.
[55] Sargent & Lundy, *Coal-Fired Power Plant Heat Rate Reductions*, SL-009597, January 22, 2009; Sargent & Lundy, *Heat Rate Improvement Method Costs and Limitations Memo,* March 2023.
[56] US Department of Energy, National Energy Technology Laboratory, *Options for Improving the Efficiency of Existing Coal-Fired Power Plants*, DOE/NETL-2013/1611, April, 1, 2014.

**Table 7. Cumulative $CO_2$ emission reduction summary for a combination of three "off-the-shelf" heat rate improvements – coal pulverizer improvement, condenser improvement, and turbine upgrade - at two model plants**[57]

| Plant | Heat Rate, Btu/kWh[ii] | Pre-retrofit $CO_2$ Emissions, Million tonne/yr[iii] | Post-retrofit $CO_2$ Emissions, Million tonne/yr[iii] | Reduction in $CO_2$ Emissions, Million tonne/yr |
|---|---|---|---|---|
| Plant A – Lower Bound | 10,012 (547 reduction) | 3.93 | 3.73 | 0.20 (5.1%) |
| Plant A – Upper Bound | 9,828 (731 reduction) | 3.93 | 3.66 | 0.27 (6.9%) |
| Plant B – Lower Bound | 9,510 (170 reduction) | 3.60 | 3.54 | 0.06 (1.7%) |
| Plant B – Upper Bound | 9,340 (340 reduction) | 3.60 | 3.48 | 0.12 (3.3%) |

Most HRI measures, in and of themselves, would not be expected to increase $SO_2$, NOx, PM or mercury emissions; however, they may potentially change economic dispatch and thereby impact total emissions. It is possible to address this with operational conditions in a permit or to incorporate improvements to emissions control technology to address any concern regarding emissions increases that might result from changes in dispatch because of the improved efficiency of the unit. If add-on controls are installed, these can generally be used to compensate for additional emissions from greater operation. In some cases the technologies can be improved, as described in more detail by ATP.[58]

## 2. Heat rate improvements to natural gas fired combustion turbines

Combustion turbine heat rate may be improved through compressor inlet cooling, or spray intercooling,[59] which can improve both heat rate *and* power output. A similar approach is wet compression, and Table 8 shows the impact of wet compression on both heat rate and on the combustion turbine power increase. The power increase for the combustion turbine (CT) results from lower compressor load (due to lower gas temperature) and higher expander output (due to higher mass flowrate). The effect is rather significant but will depend to some degree on ambient temperature. There is also a small increase in steam turbine power, which is the result of greater heat transfer in the heat recovery steam generator. A disadvantage of this approach is that water is needed. Turbine inlet cooling (TIC), which uses a chiller to cool the air at the compressor inlet,

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[57] *Id.* at 3.
[58] Staudt, J., Andover Technology Partners, *Opportunities for Reducing Acid Gas Emissions on Coal-Fired Power Plants*, for Center for Applied Environmental Law and Policy (CAELP), April 5, 2022.
[59] Spray Intercooling, or SPRINT, is a technique offered by General Electric.

also improves heat rate and increases power output because the power used by the chiller is less than the reduced load on the compressor. Therefore, there are a number of means available to owners of combustion turbines to improve the heat rate of the turbines that may also increase output power.[60] For NGCC or other facilities with steam turbine cycles, there are additional means available to improve heat rate that are described in the following section.

**Table 8. Effects of wet compression on power output and heat rate for NGCC plants[61]**

| Combustion Turbine | Siemens W501FC | Siemens V84.2 | GE LM2500PE | GE Frame 6B | SWPC W501D5A | Alstom GT-24 |
|---|---|---|---|---|---|---|
| Overspray, % | 1.3 | 1.0 | 2 | 1 | 2 | 1.2 |
| Compressor Discharge Temperature Reduction, °F | 90 | 50 | Data not available | 50 | 100 | 48 |
| Fuel Flow Increase, % | N.D. | N.D. | 4 | 8.2 | 13.2 | 5.5 |
| Change in Base Load Firing Temperature, ºF | No Change | No Change | No Change | No Change | No Change | No Change |
| CT Power Increase, MW | 17 | 5.2 | 1.6 | 3.3 | 15 | 11.5 |
| Steam Turbine Power Increase, MW | Simple Cycle | Simple Cycle | -.5 | 0.3 (est.) | 2 (est.) | 1.8(est.) |
| CT Heat Rate Improvement, % | N.D. | 2 | 0 | 1 | 2 | 2 |
| NOx Info | 10% | N.D. | -14% | DLN | DLN | No Change |

N.D.: Not Determined
DLN: Dry Low NOx

### 3. Steam turbine cycle improvements

It is also possible to improve the efficiency and output of a facility through improvements to the steam turbine cycle of a combined cycle facility or a steam EGU. This can be achieved though improvements to the steam turbine flowpath or through reductions in parasitic loads that might include upgrades to feed pumps or conversion of large, electrical motor loads (such as fans or pumps) to variable speed drives. These are explored by Sargent & Lundy in work for EPA.[62]

## D. Utilization of batteries or other storage technology on fossil plants to manage capacity factor

It is possible to utilize storage technology to manage the capacity factor of facilities. If, for example, there are multiple 300 MW combustion turbine units at a facility, each at a modest

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[60] Staudt, J., Andover Technology Partners, *Improving Heat Rate on Combined Cycle Power Plants,* for Environmental Defense Fund, October 3, 2018; available at: https://www.andovertechnology.com/wp-content/uploads/2021/03/C_18_EDF_FINAL.pdf.

[61] Shepherd, D., Fraser, D., "IMPACT OF HEAT RATE, EMISSIONS AND RELIABILITY FROM THE APPLICATION OF WET COMPRESSION ON COMBUSTION TURBINES", http://www.energy.siemens.com/US/pool/hq/energy-topics/pdfs/en/gas-turbines-power-plants/5_Impact_of_Heat_Rate.pdf.

[62] Sargent & Lundy, *Coal-Fired Power Plant Heat Rate Reductions*, SL-009597, January 22, 2009; Sargent & Lundy, *Heat Rete Improvement Method Costs and Limitations Memo,* March 2023.

capacity factor of around 50%, it may be possible to run one unit at a very high capacity-factor with the use of energy storage to manage load variability. The emission requirements for a base-loaded combustion turbine would be applied to that unit. Also, the more steady operation of the base-loaded combustion turbine would be expected to result in more efficient and lower emitting operation. For the other unit, a lower capacity factor would permit it to use a less stringent method of control, or no controls if it so chooses, as a non-covered unit.

A similar opportunity exists for existing fossil (especially, coal) steam facilities that may have a near-term unit and a longer-term unit at the same site. If the near-term unit is used primarily to provide load following or peaking power during high load periods, it may be possible to reduce the near-term unit's operations to below 20% capacity factor with energy storage in combination with the long-term coal steam unit, that could be equipped with BSER. The long-term unit would be well controlled and operate at a higher capacity factor than it would if the near-term unit were to continue to operate at a higher capacity factor than 20%.

There are real examples of using storage to reduce the capacity factor of combustion turbines. The Marin Clean Energy (MCE) project incorporates energy storage to reduce the operation of a natural gas plant that is used to provide grid reliability where there are intermittent renewable generating resources. Energy storage enables load to be shifted from the combustion turbine to wind or solar, reducing the capacity factor of the combustion turbine and increasing the utilization of the renewable resources. "During the period of April 1 to July 31, 2023, compared to the same time frame in 2002 shows the following reductions:

- Starts –62%
- Hours –86%
- Gas –90%"[63]

Reductions in gas usage are directly proportional to reductions in $CO_2$ emissions. There are other benefits. The MCE project has improved local air quality by reducing particulate emissions by as much as 78%.[64]

## E. Integrated renewables to improve efficiency or reduce parasitic load and/or increase output[65]

According to the proposed rule, "[h]ybrid power plants combine two or more forms of energy input with an integrated mix of complementary generation methods."[66] The rule stated that, "the most relevant type for energy (e.g., concentrating solar thermal) with a fossil fuel-fired EGU."[67] EPA did not propose hybrid power plants as BSER because of uncertainty about the cost-

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[63] https://www.powermag.com/content-collection/top-plant-hybrid-plant-provides-a-cleaner-power-solution/?oly_enc_id=4880A8264256C9N

[64] *Id.*

[65] EPA in its proposal suggests that this method of demonstrating compliance could be permitted. *See* 88 Fed. Reg. at 33,333.

[66] *Id.* at 33,317.

[67] *Id.*

effectiveness of the technology.[68] Solar steam power plants are in existence, while small in number.[69] Solar PV and wind are more widely used, and potentially could be integrated with fossil plants.

### 1. Solar feedwater heating

The Department of Energy's (DOE's) National Energy Technology Laboratory (NETL) examined the potential for solar-assisted feed water heaters in reducing heat rate and $CO_2$ emissions at two model 550 MW net coal steam plants assumed to be located in two different locations. The results are shown in Table 9. As expected, the plant in Arizona had a greater improvement in heat rate and reduction in $CO_2$ emissions due to the greater potential for solar feedwater heating in the warmer and sunnier climate of Arizona. NETL examined the economics of a number of options and acknowledged that the newness of the technology made the economics uncertain; however, the reduction in emissions, which would roughly be in proportion to the reduction in fuel use, was significant at 7.1% for the Arizona model plant.

**Table 9. Solar assisted feedwater heater $CO_2$ emission reduction summary (Plant A is in Phoenix, AZ and Plant B is in Indianapolis, IN)[70]**

| Plant | Heat Rate, Btu/kWh[v] | Pre-retrofit $CO_2$ Emissions, Million tonne/yr[vi] | Post-retrofit $CO_2$ Emissions, Million tonne/yr[vi] | Reduction in $CO_2$ Emissions, Million tonne/yr |
|---|---|---|---|---|
| Plant A | 9,820 (739 reduction) | 3.93 | 3.65 | 0.28 (7.1%) |
| Plant B | 9,332 (348 reduction) | 3.60 | 3.47 | 0.13 (3.6%) |
| New Subcritical PC | 9,277 (n/a) | 3.45 | - | - |

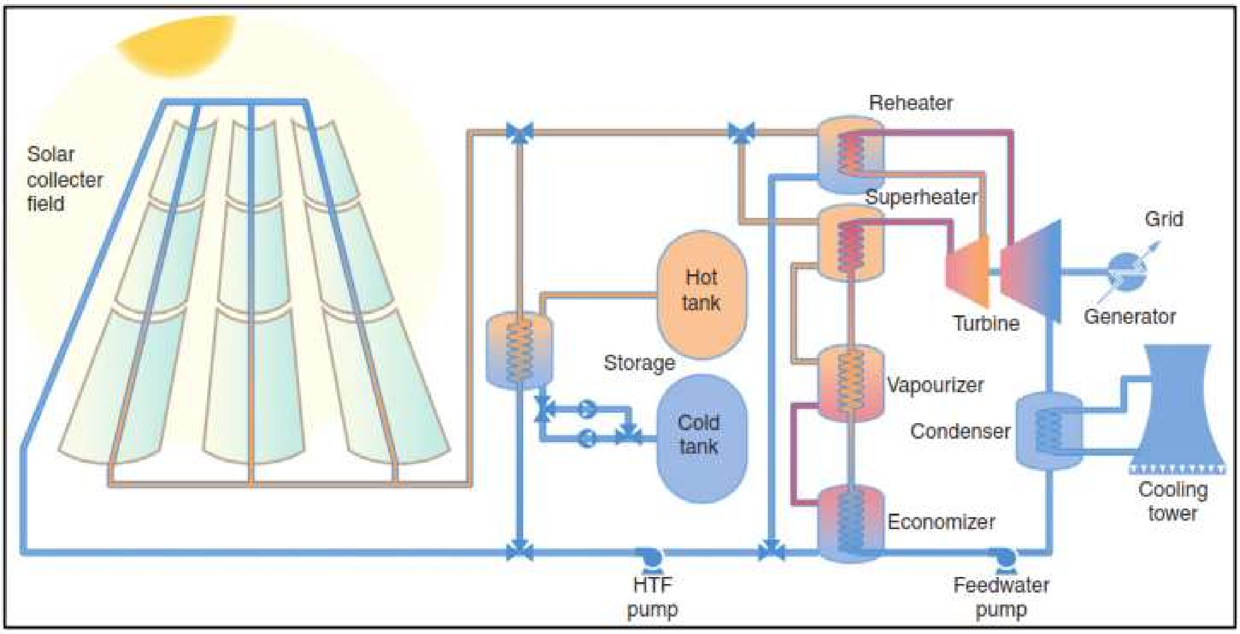
### 2. Solar thermal steam generation

A more comprehensive hybrid form of solar power might use concentrating solar collection systems to heat a fluid used to store heat or raise steam, as shown in Figure 10. In such a system, a fluid (often a molten salt) is recirculated through concentrating solar collectors. The heated fluid may be stored in a hot storage tank, or utilized in heat exchangers to raise steam. The system could be used in combination with fossil energy systems. In existing coal or gas facilities, the concentrating solar system could be used to preheat feedwater, as described in the prior section.

[68] *Id.*
[69] https://www.eia.gov/energyexplained/solar/solar-thermal-power-plants.php
[70] US Department of Energy, National Energy Technology Laboratory, *Options for Improving the Efficiency of Existing Coal-Fired Power Plants*, DOE/NETL-2013/1611, April, 1, 2014, p. 6.

Alternatively, in new natural gas combined cycle facilities, the concentrating solar system could be integrated into the heat recovery steam generator and the steam cycle to produce a lower emissions rate and could lower the amount of low-GHG hydrogen or capture needed to reach the emissions performance rate reflecting application of the BSER.

**Figure 10. Solar thermal trough power plant with thermal storage[71]**




## 3. Integration of geothermal

The US Department of Energy is also studying combination of geothermal with fossil power to produce a more efficient fossil fuel plant. *"This humidified cycle can make use of low-temperature geofluid water, normally applied only for heating, to generate power at higher geofluid efficiencies than typical geothermal cycles. The hybrids use less natural gas, per unit of electricity produced, than conventional combustion turbines as well as less water than water-cooled combustion-based power cycles."*[72] This, of course, is limited to locations that have access to geothermal energy.

## 4. Hybrid power generation

Hybrid power generation, or the use of renewable energy at the same site as a fossil fuel facility, could be used to reduce the plant parasitic loads of a fossil fuel plant. Depending upon the configuration of the facility, the fuel characteristics, and the location, coal steam plant parasitic loads typically consume at least 6% and sometimes close to 10% of the gross generation of a

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[71] Mills, S., "Combining Solar Power with Coal-Fired Power Plants, or Cofiring Natural Gas", *Clean Energy*, 2018, Vol. 2, No. 1, 1-9.

[72] https://www.energy.gov/fecm/articles/netl-group-combines-fossil-energy-research-studies-geothermal-energy-potential

facility. Some of this plant load could be provided by renewable generation co-located at the facility, and this would effectively reduce the $CO_2$ emission rate of the facility. Also, the addition of renewables in combination with energy storage could also facilitate reducing the capacity factor of the fossil units, and thereby perhaps reduce the control requirements for those fossil units. The type of renewable generation would depend upon the specific characteristics of the site – whether it is best suited for solar PV versus wind, etc.

This could also be utilized as facilities transition from fossil to renewable energy. Fossil plants can provide excellent locations for installing renewables because the transmission system is already located at the site. For example, the shuttered Brayton Point coal power plant will become a renewable energy hub, both having manufacturing for advanced undersea cables used in offshore wind farms and being a hub for 1,200 MW in generation from offshore wind farms that send power to the site for distribution.[73] This type of conversion of fossil facilities to renewable will be limited to those facilities that lend themselves to co-location of renewable generation. But, for such facilities, renewable generation, perhaps with energy storage, could be added to displace fossil power generation and reduce the capacity factor of existing fossil EGUs. Coal plants in Illinois – Baldwin, Havana, Joppa, Edwards, Waukegan, and Will County – will be incorporating renewables and in some cases energy storage. Similar projects are being planned in Nevada, New Mexico, Colorado, North Dakota, Nebraska, Minnesota and Maryland. The Mount Tom plant in Massachusetts is incorporating solar PV as well as energy storage.[74] So, this is a current trend that could continue.

### 5. Combined Heat and Power (CHP)

CHP is not necessarily renewable. But, CHP does produce both thermal and power output. EPA considered CHP and hybrid power plants in developing the proposed rules.[75] EPA did not propose CHP as BSER because the agency expected that CHP would be very limited in availability due to the requirement for a large, thermal host.

## F. Shifting load to lower-emitting units

Shifting load to lower emitting units can reduce the cost of compliance.

A shift to lower emitting units as a general rule will also reduce cost of compliance. If higher emitting units retire earlier (becoming medium term coal versus longer term coal units, for example) or reduce capacity factor (shifting from base load to intermediate load combustion turbines, for example) as generation is shifted to lower emitting units, this will lower the requirements for compliance on those units. This has occurred in prior programs and will likely occur in the future. Figure 11 shows the historical electricity generation mix and EIA's reference

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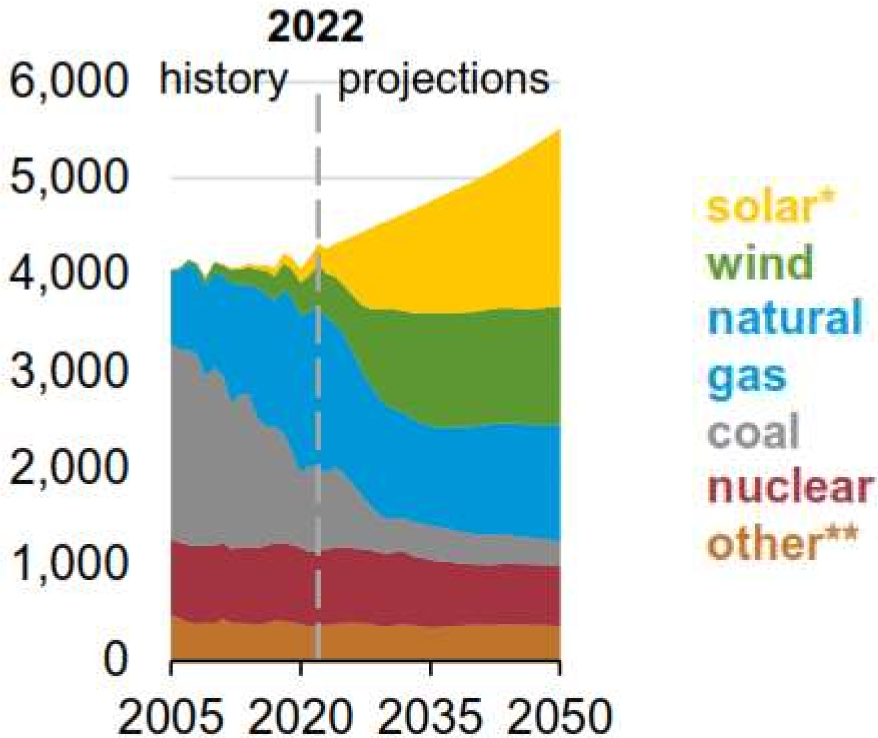
[73] https://www.prysmiangroup.com/en/insight/sustainability/prysmian-group-creating-renewable-energy-hub-in-united-states-at-brayton-point

[74] https://www.nytimes.com/2022/07/15/climate/coal-plants-renewable-energy.html

[75] 88 Fed. Reg. at 33,317.

case forecast. As shown, during the period while CAIR/CSAPR and the MATS rule were being implemented there was a transition away from coal and toward natural gas and renewable power. This transition away from higher-emitting sources to lower-emitting sources of energy contributed to reducing the cost of complying with those rules. Looking forward, coal generation is expected to be reduced absent the proposed rule,[76] which will reduce the cost of compliance from what it would be if that coal capacity were to remain in service for the long term.

**Figure 11. EIA 2023 reference case forecast for net electricity generation by energy source (billion kWhrs)[77]**




Under an averaging or trading scenario, a facility owner may shift load from higher-emitting units to lower-emitting units. States may implement a trading program to achieve emission reductions that can be demonstrated to be equal or better in terms of stringency than if EPA's proposed BSER were applied to individual facilities. Such a trading program could facilitate shifting of load from higher to lower emitting facilities to meet the requirements of the proposed rule. The proposal provides presumptively approvable emission rates. For a rate-based trading program, for example, the proposal describes an approach where facilities that emit below their emission rate limit can produce tradeable credits denominated in units of one ton of $CO_2$.[78]

[76] EIA reference case projections include the estimated impacts of finalized rules or statutes, but do not include impacts of proposed rules or statutes.

[77] EIA Annual Energy Outlook, 2023 AEO Release Presentation, p. 14, available at: https://www.eia.gov/outlooks/aeo/pdf/AEO2023_Release_Presentation.pdf

[78] 88 Fed. Reg. at 33,394.

In this situation, if more load gets transferred to units operating at well below the associated presumptively approvable emission rate-based limit, more credits can be generated from operation of that unit that could be made available for units with higher emission rates that would be operated less. In this manner, a trading or averaging program could facilitate transfer of load from higher-emitting units to lower emitting units.

## G. Combinations of the above strategies and future innovations

The above strategies may be combined. Also, it is perhaps more likely that new innovations will be developed that expand the options available for compliance with the rule.

### 1. Combinations of strategies

The above strategies, especially those strategies that are incorporated into BSER, can often be combined. Efficiency improvements and changes to lower emitting fuels (including biofuels or lower moisture coal) can be combined with any of the presumptive compliance approaches. For example, efficiency improvements will reduce the amount of natural gas necessary to reach the 16% emission rate reduction that is the presumptively approvable standard for medium-term coal units. If low-GHG hydrogen is available for medium-term coal units, 16% emission rate reduction can be achieved with less than 40% natural gas and hydrogen cofiring by heat input. To take a more comprehensive example, although it would be novel and potentially not the most cost-effective approach, it is possible to imagine a coal-fired power plant that retrofits with very high levels of carbon capture, cofires some amounts of gas and hydrogen, and integrates renewables and battery storage to lower parasitic load, reducing ramping, and keep some units at the facility below capacity factor thresholds—ultimately planning to replace all units with renewables.

Because the proposed rule allows states to utilize flexible approaches for compliance, such as averaging and trading, this also opens opportunities for more systemwide approaches that, overall, are at least as stringent as if BSER were applied to each source, but at a lower overall cost. Programs that include averaging or trading of emissions create an incentive for each source to lower its emissions rate in every way that is cost-effective given its particular circumstances—whether the source ends up with a rate above or below the presumptively approvable standard of performance. Accordingly, some of the techniques discussed in this section that are not as effective in reducing $CO_2$ emissions rates or overall $CO_2$ emissions could ultimately be deployed where they otherwise would not have been—either because they would not have sufficed for an individual source to comply, or because the source would not have any incentive to reduce emissions below its standard.

### 2. Innovative measures that may be developed in the future

Because the proposed rule has identified presumptively approvable emission rates and allows states flexibility to develop plans that can be demonstrated to be at least as stringent as if BSER were applied, there is the potential to develop other strategies or technologies that achieve the same objective. As described in greater detail by ATP,[79] historical experience with other EPA programs demonstrates that industry innovates to find approaches that may not be envisioned when the rule is developed. In the past, when industry was faced with the need to reduce emissions, they consistently developed new approaches for reducing emissions, many that were not envisioned when the rule was formulated. Moreover, those innovative techniques were frequently more cost-effective than the pollution controls originally anticipated by EPA. For example, the cost of complying with MATS was determined to be much lower than EPA had anticipated due to the advancement of technologies not anticipated to be deployed as effectively by EPA.[80] Also, the development of flue gas conditioning facilitated the transition to lower sulfur coals at a much lower cost than would otherwise be possible, reducing the cost of complying with the Title IV requirements of the CAA.[81] For these reasons, it is likely that industry will find other technical solutions that achieve the same goals of reducing $CO_2$ emissions, but at a lower cost than currently projected.

The tendency for innovation occurring after the issuance of a regulation is the result of two forces:

- Facing the need to comply with emissions standards, EGU owners become innovative in looking for lower-cost means to comply with emissions standards than those EPA plans on when estimating the cost of the rule. Low-cost solutions that companies might have dismissed prior to a rule taking effect receive more attention. Necessity becomes the mother of invention.
- With a market available for lower cost solutions, technology suppliers respond. They develop lower cost options and technologies that achieved lower emissions than EPA plans on in estimating the cost of the rule.

There are examples to draw from in prior EPA programs. They are discussed below:

### *a. NOx RACT (reasonably available control technology)*

When US EPA developed NOx RACT guidance with presumptive NOx emission rates for coal-fired boilers, EPA allowed states to adopt other rates, expecting states would "to the extent practicable, to demonstrate that the variety of emissions control adopted are consistent with the most effective level of combustion modification reasonably available for its individual affected sources."[82] In 1992, when EPA developed its presumptive NOx RACT emission rates, no post-combustion technology had ever been retrofit on a coal-fired EGU in the United States, and SNCR technology was not in commercial operation anywhere on a coal-fired EGU. Hence, it was clear

[79] J. Staudt, Andover Technology Partners, *History of Flexible Compliance with Science-Based and Technology-Based Stationary Source Air Pollution Regulations*, December 18, 2023.
[80] *Id.* at 17-20.
[81] *Id.* at 23-26.
[82] 57 Fed. Reg. 55,620, 55,626 (Nov. 25, 1992).

at that time that EPA expected NOx RACT to be complied with through combustion controls. However, as described by Staudt, many facilities utilized post-combustion controls for complying with NOx RACT requirements, and in some cases states set even lower NOx emission rates as NOx RACT than EPA's presumptive NOx RACT limits.[83]

### b. Mercury control innovation

Another example of technologies being deployed for compliance that were not envisioned at the time of rule development are mercury control technologies developed after the promulgation of the MATS rule in 2012. Some of these developments include new mercury capture sorbents that were not available in 2012.[84] Other developments include methods to improve mercury capture in FGD systems that were not available in 2012.[85] Regarding the latter approach, as a result of improved understanding of the chemistry associated with the capture of mercury in wet FGD systems, it became possible to dramatically improve the capture of mercury in these systems.

### c. Title IV and fuel switching

The Title IV Acid Rain Program in the 1990 CAA Amendments required $SO_2$ emissions reductions from coal-fired EGUs. With a trading program in the rule, these facilities would: 1) add FGD to reduce $SO_2$ emissions; 2) use fuels with lower sulfur content; or 3) make no changes and acquire allowances from units that had reduced their emissions. But changing to lower-sulfur fuels would adversely impact the performance of the particulate matter (PM) control device (specifically, the electrostatic precipitator). Innovation played a major role in facilitating the ability to use lower-sulfur coals. Flue gas conditioning, which would not be patented until 1993, enabled the use of lower sulfur coals without adversely impacting the performance of the PM control devices.[86]

[83] J. Staudt, Andover Technology Partners, *History of Flexible Compliance with Science-Based and Technology-Based Stationary Source Air Pollution Regulations*, December 18, 2023, pp. 12-15.

[84] J. Staudt, Andover Technology Partners, *Analysis of PM and Hg Emissions and Controls from Coal-Fired Power Plants,* prepared for Center for Applied Environmental Law and Policy, August 19, 2021, pp. 47-51.

[85] *Id.* at 46-47.

[86] J. Staudt, Andover Technology Partners, *History of Flexible Compliance with Science-Based and Technology-Based Stationary Source Air Pollution Regulations*, December 18, 2023, pp. 24-25.

## IV. Conclusion

This report evaluated the proposed CAA Section 111 GHG rules for fossil fueled power plants. Section 111 is expressly designed to provide compliance flexibility by requiring emissions performance standards, rather than mandating the use of any particular technology at new or existing emissions sources. Further, Section 111(d) authorizes states to develop plans for their existing sources that achieve a level of stringency that is at least as stringent as if the proposed BSER were deployed on each unit subject to the rule. The flexibility provisions permit the use of a wider range of technologies and compliance approaches than the BSERs identified in the rule.

In formulating the proposed rule, EPA reviewed adequately demonstrated systems and chose the best ones, considering the statutory factors of emission reductions, costs, environmental side effects, energy requirements, etc. Based upon the BSER that EPA identified for a given subcategory, EPA also proposed emission rate standards for new sources and presumptively approvable emission rate standards for existing sources.

Once the standards are finalized, owners and operators of EGUs can choose whichever approach is most desirable in meeting the emission standard, given their own particular circumstances. It is permissible to choose a technical approach that is not the BSER identified in the rule but achieves at least the same or a greater level of stringency. In this manner, improved technologies or other innovations may be utilized. This is also consistent with the statutory objective of promoting technical innovation. Indeed, this report identified examples of technical innovation that occurred in the past with other pollution control programs implemented under Section 111 and other sections of the CAA.

The proposed rule also permits states to develop trading or emission averaging programs so long as these programs provide at least the same level of stringency as if BSER were applied to each facility.

The emission rate standards that can be met through any effective technology combined with the other flexibility mechanisms available under the rule open the opportunity to use a range of technologies and approaches to meet the requirements, many of which were explored in this report, and some that will almost certainly be developed in the future as the rule is implemented, if compliance with past CAA rules is any indication. With this wide array of compliance measures, EPA's proposed rule can secure GHG emission reductions needed to protect public health and welfare, while keeping costs low and promoting technological innovation.