July 25, 2025

To: Center for Applied Environmental Law and Policy

Fm: Jim Staudt, PhD, Andover Technology Partners

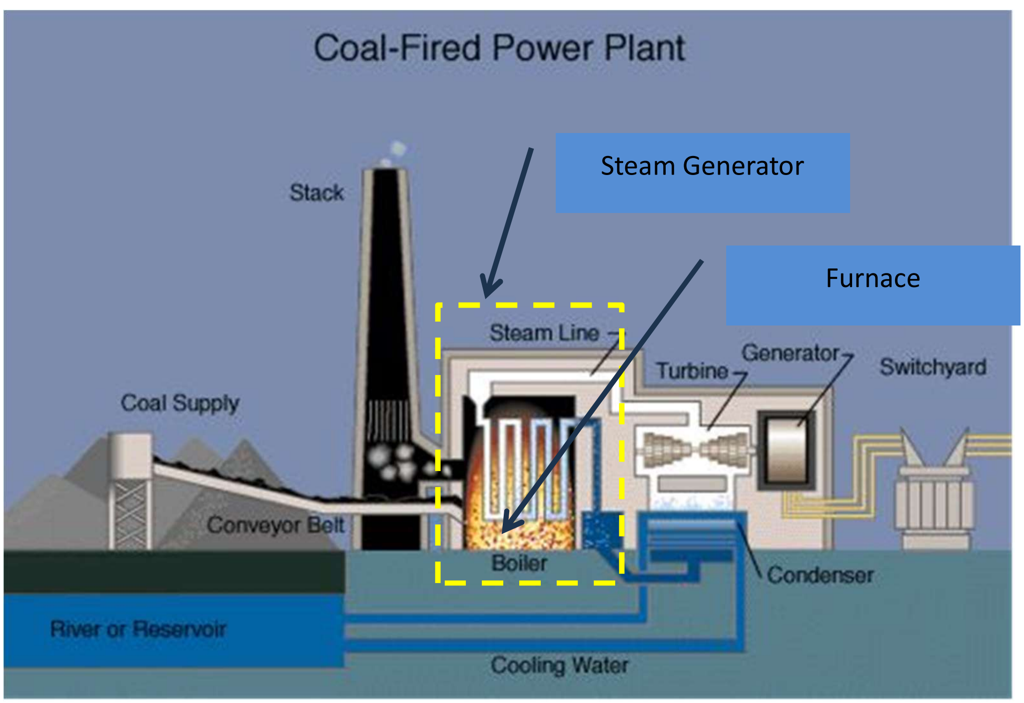
Re: Natural Gas Cofiring On Coal Fired Boilers

1 COAL FIRED POWER PLANT BASICS

Figure 1 shows a simplified diagram of how a coal-fired boiler generates electricity through a conventional steam cycle that engineers call the Rankine Cycle. Starting from the left, fuel and air are combined in a furnace (the inner portion of the boiler or steam generator where the fuel is burned) to form a flame that changes the chemical energy bound in the fuel into heat. This fuel can be coal, oil, or natural gas, or a mix of multiple fuels—in the case of a coal-fired power plant, the primary fuel is coal. The steam generator, or boiler, is within the yellow, dashed rectangle. The exhaust from the flame is comprised of combustion products – nitrogen, water vapor, carbon dioxide, other gases and particle matter that are released to the atmosphere through a smoke stack. In the boiler, the heat from the flame is used to heat water to generate steam at a high pressure.

In a coal-fired power plant, this high-pressure steam is used to power a turbine that drives a generator to produce electricity. The steam exhausts from the turbine at lower temperature and pressure and is cooled even further to condense to water. Cooling water normally flows through the condenser to cool the steam to water. The condensed water is then pumped back to the steam generator at high pressure to be re-heated to steam.

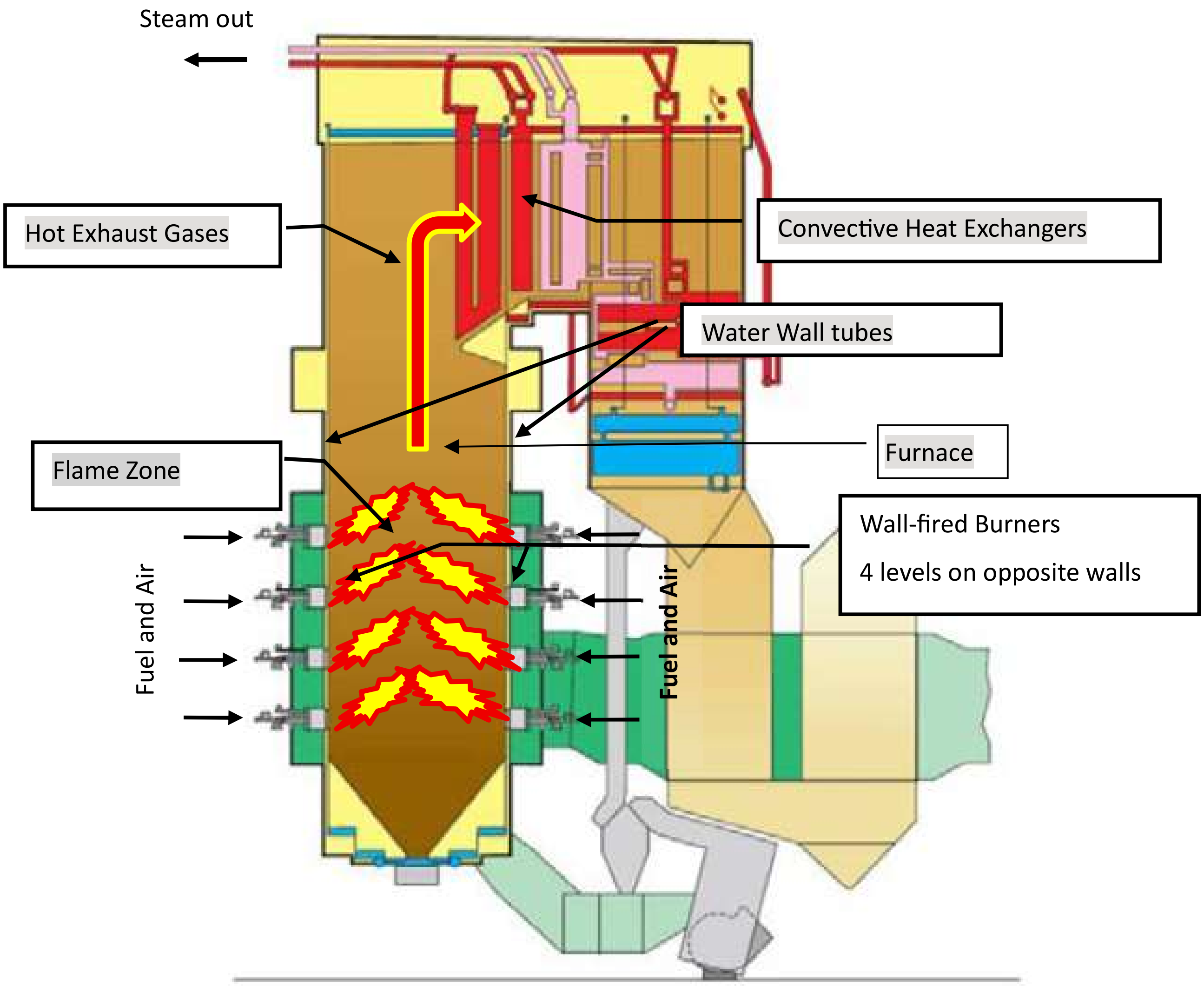
Figure 1. Simplified diagram of a coal-fired conventional steam power plant.[1]



[1] from TVA's web site, http://www.tva.gov/

The steam generator or boiler is where the chemical energy of the fuel is converted to useful, high pressure steam. The steam generator is typically a tall, rectangular structure. Figure 2 shows the parts of a modern steam generator. The furnace is the part of the steam generator where the combustion occurs, forming hot gases. This particular figure shows four levels of wall-fired burners (burners installed into the two, opposite walls of the furnace, flames shown), where the fuel and air combine and burn, releasing heat and creating hot gases. The combustion exhaust gases leave the furnace and transfer their heat to water or steam that is at high pressures within steel tubes that are in the furnace wall ("water wall" tubes – arrays of tubes that form the wall of the furnace) or are suspended in the gas stream as part of convective heat exchangers. The transfer of heat from the exhaust gases to the water has the effect of cooling the exhaust gases and heating the water and steam within the tubes.

Figure 2. A Coal-Fired Steam Generator (aka, "boiler") [2]



[2] Babcock & Wilcox Company, https://www.babcock.com/assets/PDF-Downloads/Upgrades-Parts-Services-Controls/E101-3269-Boiler-Fuel-Conversions.pdf (flames and other annotation were added)

Most electric utility coal fired boilers are pulverized coal (PC) boilers. The coal is finely-ground in a device called a pulverizer where it is ground to a fine powder and the pulverized coal is combined with air (“primary” air) before being sent to the burner. Burners are where fuel and air are mixed and the flame is formed, releasing the chemical energy in the fuel as heat. There will typically be several burners on any electric utility coal-fired boiler.

Figure 3 shows an example of a coal burner. The primary air and the entrained, pulverized coal are transported into the burner (see Figure 3 where it says “coal and primary air inlet”) and introduced to the coal nozzle. Additional air is also combined in the burner and carefully mixed with the coal and primary air in the furnace. It is necessary to admit enough air to burn as much of the fuel as possible. The actual flame is within the furnace in the flame zone of Figure 2. The burner shown in Figure 3 is for what is called a wall-fired boiler because a series of these burners are installed in the water walls of the furnace. Instead of having burners in the wall of the furnace, burners may alternatively be installed in the corners of the furnace in a vertical array, as shown in Figure 4. In this case, three burner levels are shown (there would be a similar burner array in each of the four corners of the furnace). Only one burner, the middle, gas-fired burner, is firing in this figure and the upper and lower coal burners are not firing.

Coal fired boilers start up on other fuel, typically either natural gas or fuel oil. The burners have a pilot, or an “igniter”, which provides the ignition fuel and produces a flame used for start up. These igniters are typically on a sleeve and are inserted into the furnace on start up. When the furnace is burning coal and at a high enough temperature to turn off the igniters, the igniters are typically turned off and withdrawn from the furnace. A wall-fired burner with an igniter is shown in Figure 5.

Figure 3. A coal burner for a large coal-fired steam generator[3]

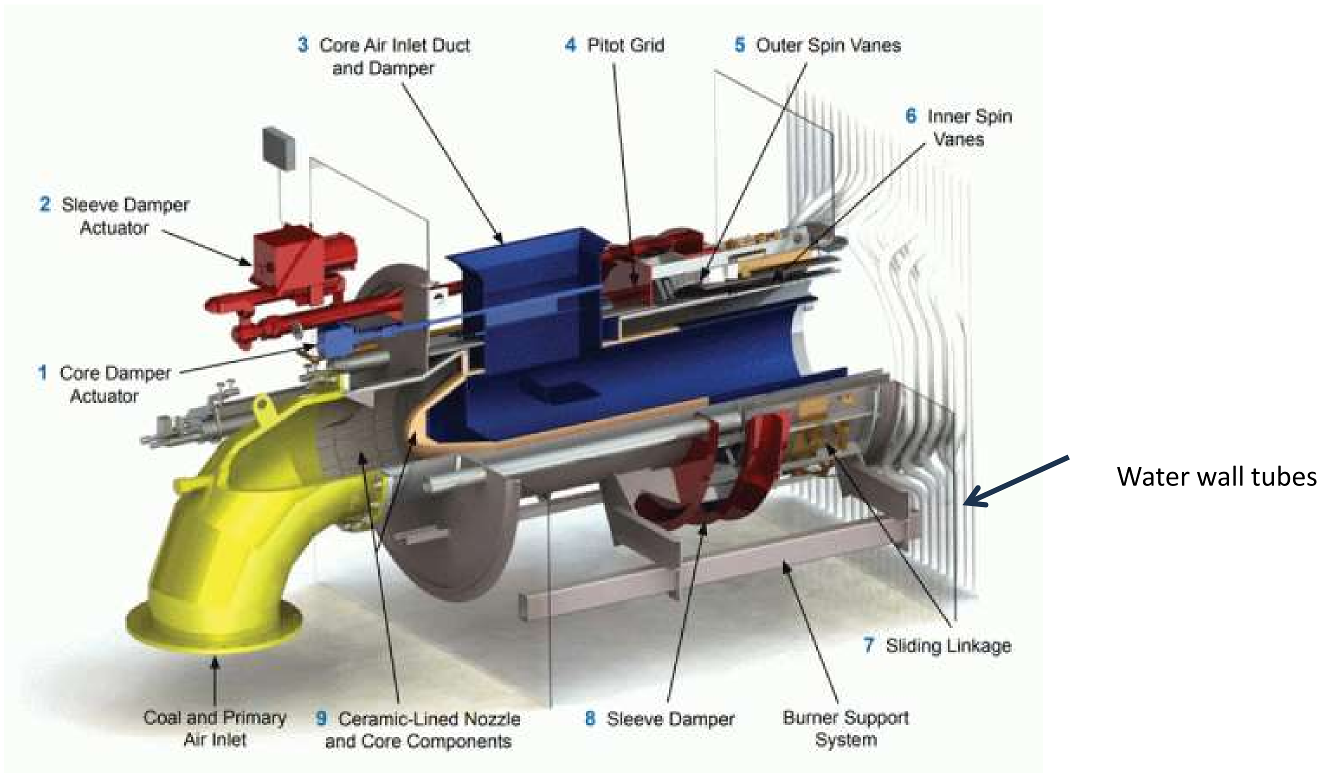
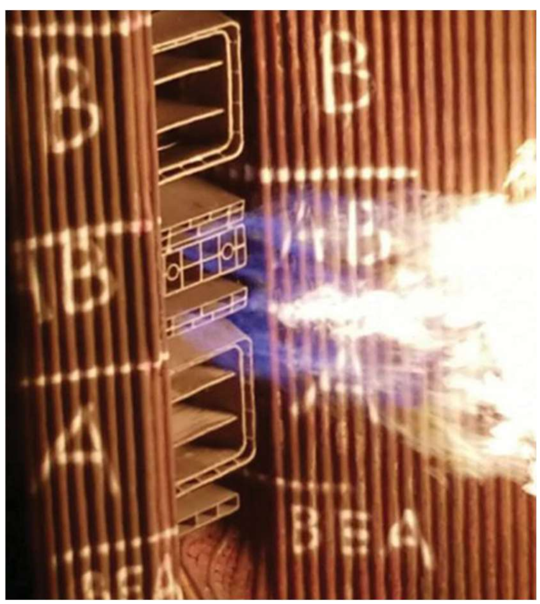


Figure 4. Corner-fired burners and a natural gas flame[4]



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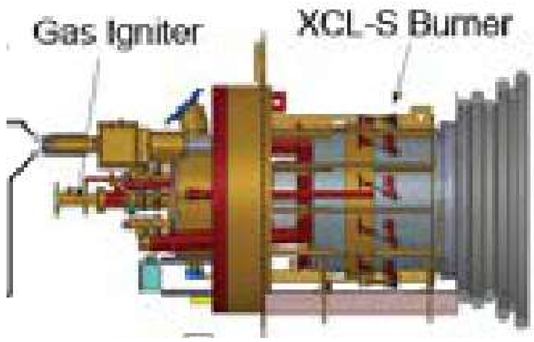
[3] Ibid
[4] https://www.babcock.com/home/thermal/boiler-fuel-conversions

Figure 5. Coal burner and gas igniter[5]



2 NATURAL GAS COFIRING EXPLAINED

Cofiring means the use of more than one fuel. In the case of coal-fired electric generating units (EGUs), *all* cofire another fuel with coal because all coal fired boilers start up on another fuel, such as natural gas or fuel oil, because coal is harder to ignite than fuel oil or natural gas. Once heated up somewhat, the unit then transitions to coal firing as load increases, gradually reducing natural gas or fuel oil. All boilers are designed to handle a maximum amount of heat from fuel when they are running at full load. That maximum heat input is measured in units of million British thermal units (Btus) (a way to measure heat energy) per hour. Typically, start-up fuel is used up to about 10% and sometimes as high as 20% of the furnace's maximum heat input to slowly warm things up before adding coal. As the furnace load is increased, the start-up fuel (natural gas or fuel oil) may be curtailed or shut off. In some cases, as will be discussed further, the start-up fuel may continue to be fired to some degree, even when operating at full load.

2.1 Natural Gas Cofiring Involves Relatively Modest Modifications

As noted, every coal-fired EGU already cofires either natural gas or oil with the coal. And, as these EGUs have more commonly been used as a load-following generation asset (meaning the facility increases or decreases generation to meet fluctuating electricity demand, rather than running all or most of the time to meet some basic level of demand), natural gas cofiring or even conversions have become economic choices for utilities. This is because cofiring higher levels of gas allows for more rapid adjustments of generation output.

Natural gas cofiring—at levels higher than those used solely for start-up (about 10% or so of full-load input)—will typically entail some modification to the unit, and the nature of the modification will be determined by the current configuration and the level of cofiring that is desired. Modifications will normally include some changes to the burners and, depending upon the extent of cofiring and other site characteristics, changes to the fuel delivery, and sometimes modest changes to the boiler.

The existing coal burners can normally be retained and simply modified to accommodate increased use of natural gas. Corner-fired burners are already designed to handle multiple fuels while wall-fired boilers are easy to modify for gas-co-firing.[6] Figure 6 shows a coal wall-fired burner that has six gas injection ports added around the perimeter of the burner. Natural gas also needs different air flow to burn cleanly than does coal, and the plant will adjust air dampers and fans to get the right fuel-air mix.

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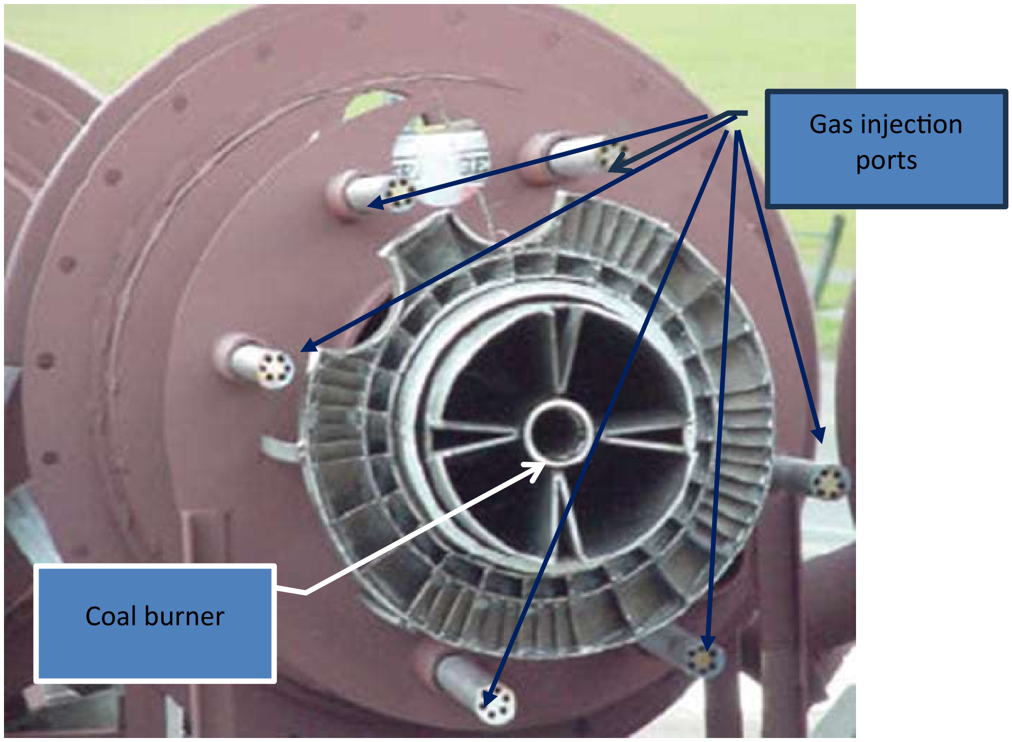
[5] Ibid

[6] https://www.powermag.com/practical-considerations-for-converting-boilers-to-burn-gas/

Figure 6. Power plant wall fired burner that can cofire natural gas and coal[7]



Considering co-firing projects where the boiler was modified to accommodate 30 to 50 percent natural gas burning , the required changes were very minimal. For example, at the Big Bend plant in Florida, the existing gas igniters were simply replaced with a newer set of gas igniters that could operate at higher load, and with this modification it was possible to accommodate 33% of the boiler's maximum rated heat input as natural gas at an installed cost of $6/kW (a measure of cost in terms of dollars per unit of generating capacity).[8] Figure 7 shows fuel firing at the Big Bend Power Plant in 2020. As shown, Big Bend exceeded 40% gas firing. It shows the amount of fuel used (bituminous coal versus natural gas) in the month, measured in terms of millions of Btus. Capacity factor is the percentage of full load rating that the plant ran that month.

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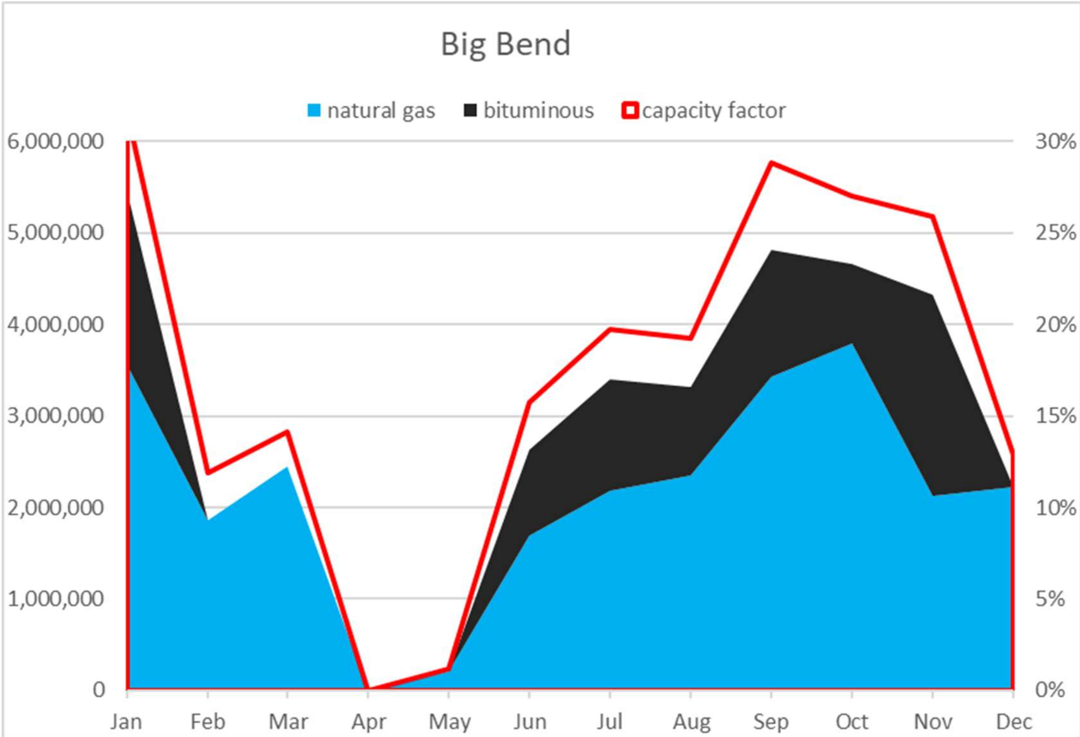
[7] https://www.powermag.com/practical-considerations-for-converting-boilers-to-burn-gas/

[8] These costs exclude any modifications to the natural gas supply equipment, such as natural gas pipeline additions that may be necessary to reach the facility or increasing the capacity of existing natural gas supply.

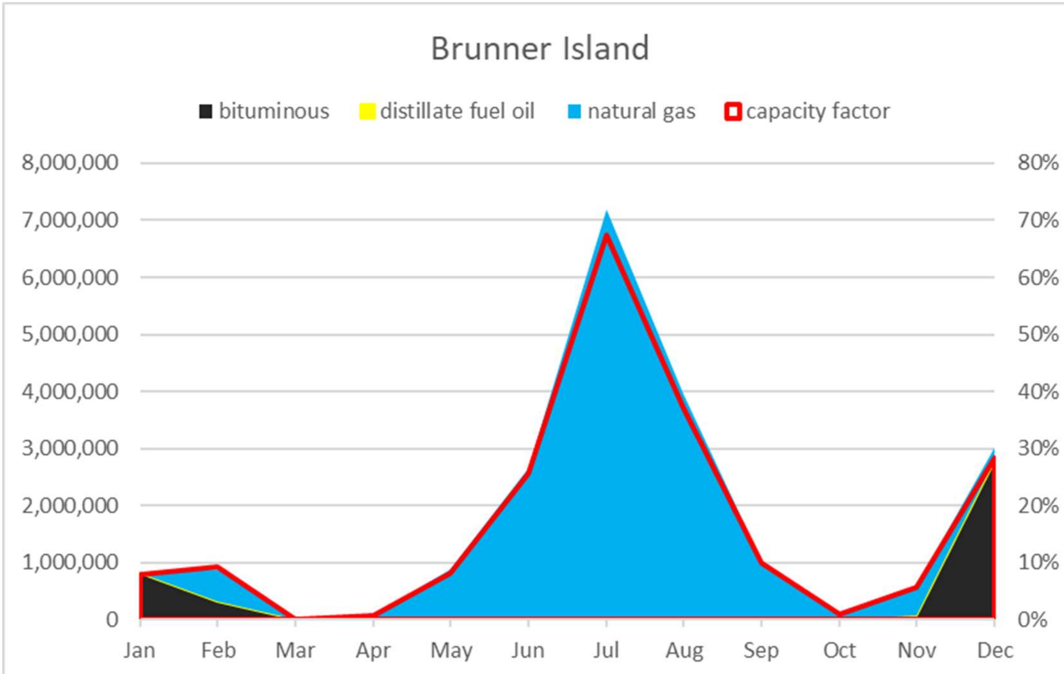
Figure 7. Fuel usage per month (million Btus) by fuel and capacity factor in 2020 for Big Bend.[9]



Using cost as an indicator of the extent and complexity of changes and modification, co-firing is by far the simplest and most inexpensive way to use natural gas instead of coal to generate electricity as compared to replacing the old coal plant with a new natural gas combined-cycle plant. For example, the Brunner Island plant in Pennsylvania, which was modified so that natural gas could provide up to 100% of the boiler's maximum rated heat input as natural gas, cost $67/kW. In this modification it was necessary to add natural gas capability to the coal burners, which is a more expensive change than simply replacing the gas igniters. Figure 8 Figure 8. Fuel usage per month (MMBtu) by fuel and capacity factor in 2020 for Brunner Island.shows the fuel usage at the Brunner Island plant in 2020. It shows the amount of fuel used (bituminous coal versus distillate fuel oil, versus natural gas) in the month. Capacity factor is the percentage of full load rating that the plant ran that month.

[9] Staudt, J. Natural Gas Cofiring for Coal-Fired Utility Boilers, for Center for Applied Environmental Law and Policy (CAELP), February 12, 2022; available at: https://www.andovertechnology.com/wp-content/uploads/2022/02/Cofiring-Report-C_21_2_CAELP_final_final.pdf; hereafter, Staudt 2022

Figure 8. Fuel usage per month (MMBtu) by fuel and capacity factor in 2020 for Brunner Island.[10]



A new natural gas combined cycle plant will cost on the order of $1,000/kW or more and a natural gas combustion turbine will cost on the order of $800-$900/kW or more. And to compare the costs of cofiring modifications to those of other emission controls for coal-fired plants, adding scrubbers to a coal-fired power plant will cost over $500/kW.

So, the conversions needed for a natural gas cofiring project are very modest in the context of modifications to coal facilities or building new natural gas facilities. In fact, as coal generation has become more load following, gas cofiring or gas conversion projects for existing coal facilities can be a very cost-effective means of addressing the need for load following compared to a new gas-fired generation plant since a plant with cofiring is in a better position to follow load.

Figure 9 compares the capital cost of different ways to use natural gas at a power plant.

- **Igniter cofiring** – Similar to the Big Bend project, this can enable burning up to about 33% of the full rated heat input as natural gas. Some facilities may differ somewhat. This only requires replacing igniters with more capable igniters and making any changes to the fuel supply. The power plant is otherwise untouched. Because most plants don't run at 100% capacity all of the time, 40% cofiring or more can be achieved in this configuration at less than 100% capacity. For example, any plant that supplies 82.5% of the energy that it would produce if it operated at full-load 100% of the time or less (this would be referred to as 82.5% "capacity factor"), 33% of maximum heat input using natural gas would be

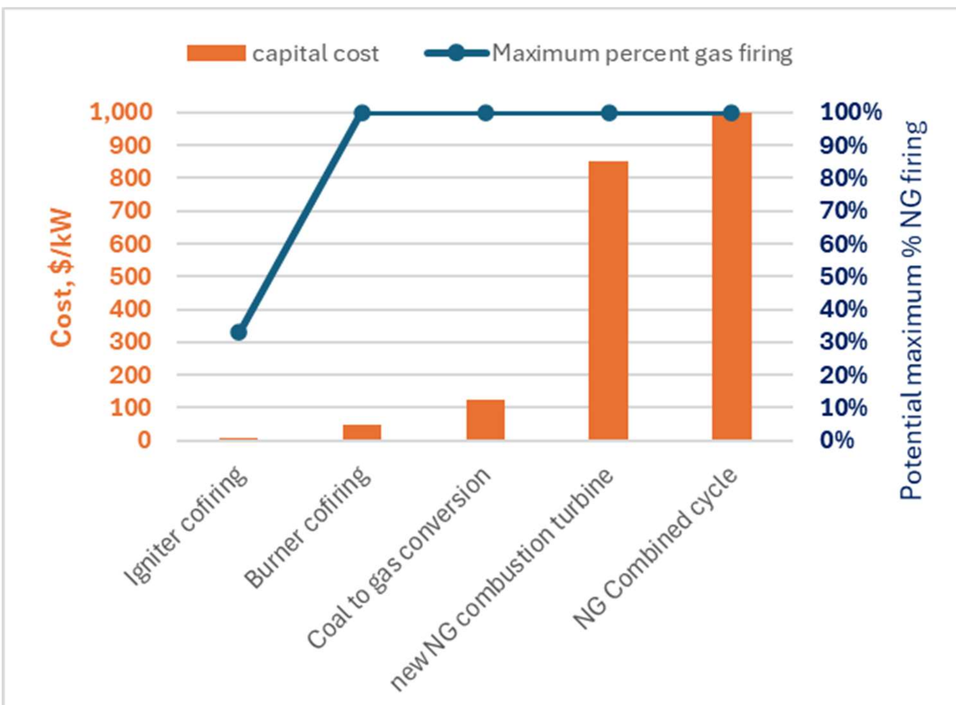
[10] Staudt 2022

sufficient to achieve at least 40% natural gas cofiring. According to DOE, the average annual capacity factor for coal was 42.6% in 2024, and no units ran more than 78%.[11]

- **Burner cofiring** – This involves modifying the burners to accommodate up to 100% firing on natural gas, while also permitting firing of both coal and natural gas at varying levels. This only requires modifying the burners, perhaps some boiler adjustments, and making any changes to fuel supply. The power plant is otherwise untouched.
- **Coal to gas conversion** – This will entail some boiler modifications, changes to the fuel system and, depending upon the situation, burner modification or burner replacement. The power plant is otherwise untouched.
- **New natural gas combustion turbine** – This would entail completely decommissioning the coal power plant and replacing it with a natural gas combustion turbine.
- **New natural gas combined cycle power plant** - This would entail completely decommissioning the coal power plant and replacing it with a natural gas combined cycle power plant, which combines a combustion turbine with a steam power plant that converts heat in the gas turbine exhaust into electrical energy.

As shown, the gas cofiring and gas conversion options are relatively inexpensive and non-invasive projects compared to new gas-fired generation because they retain most of the power plant.

Figure 9. Comparison of capital cost for different natural gas options



[11] U.S. DOE. Office of Nuclear Energy. 2025. What is Generation Capacity? https://www.energy.gov/ne/articles/what-generation-capacity; *See* U.S. Energy Information Administration Form EIA-860 detailed data with previous form data (EIA-860A/860B) for capacity data. https://www.eia.gov/electricity/data/eia860/; *See* U.S. Energy Information Administration Form EIA-923 detailed data with previous form data (EIA-906/920) for energy consumption data. https://www.eia.gov/electricity/data/eia923/.

NG cofiring and conversions are being performed on a wide range of units

2.2 Current Deployment of Natural Gas Cofiring

Figure 10 shows data developed from EIA Form 923 for coal-fired units that also fire natural gas—in some cases nearly 100% natural gas. All coal EGUs that burned 2% or more of their fuel in 2023 as natural gas are plotted in order of lowest to highest percentage of fuel as natural gas. 2% was selected as a lower threshold to eliminate most of those units that only use natural gas as a start-up fuel. As shown, 56 units co-fired natural gas and coal in 2023, with 22 units firing 40% or more of their fuel as natural gas. This compares to 12 units cofiring at levels in excess of 40% in 2020. These units include large facilities as well.

Figure 10. Natural gas % heat input in 2023 versus cumulative number of units at or below that % heat input (from EIA Form 923– only units 2% or more natural gas)

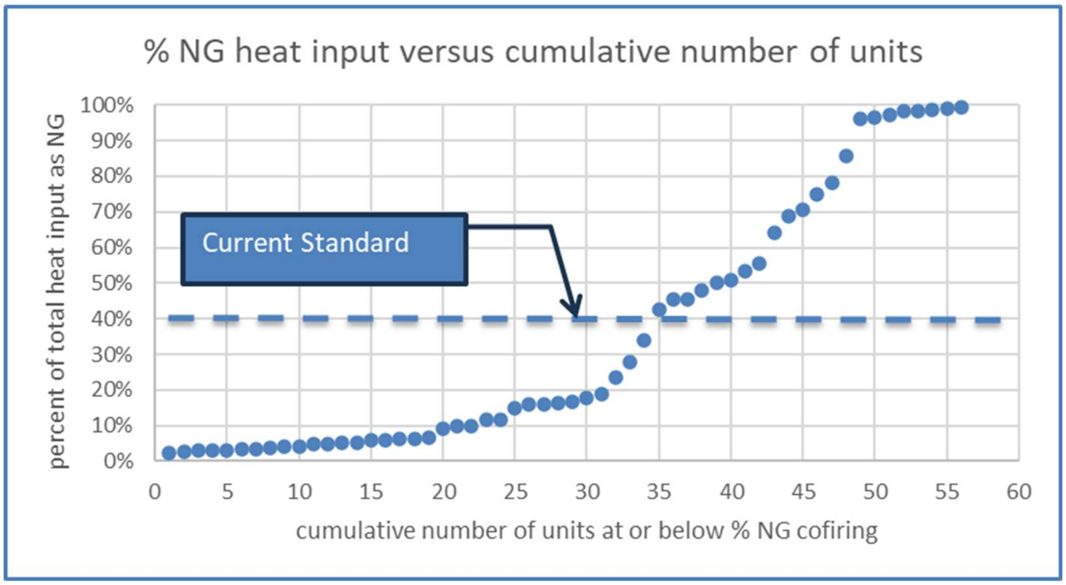


Figure 11 shows the data of Figure 10 plotted in a different way. On the horizontal axis is the cumulative total heat input for the associated units (in units of trillion Btu of fuel heat input). The larger the jump to the right for any data point demonstrates more total heat input from all fuels, which is an indicator of the size of the unit. WA Parish 5 & 6 in Texas each average 5-6% natural gas firing. Oak Grove unit 1 in Texas fired over 6% natural gas in 2023. Duke Energy's Marshall 4, Cliffside (John Rogers Energy Center) unit 6, and both Belews Creek units all used in excess of 50% natural gas in 2023, with Belews Creek 2 using 75% of its fuel as natural gas. The Brunner Island plant in Pennsylvania cofired the most natural gas, at 98%. Belews Creek, Marshall, Cliffside and Brunner Island are all discussed in more detail in Staudt 2022. Figure 12 compares the number of units cofiring at different rates in 2020 versus 2023. The trend in this figure is toward more units cofiring at higher natural gas rates.

Figure 11. Natural gas % heat input in 2023 versus cumulative heat input of all units at or below that % heat input (from EIA Form 923 – only units 2% or more natural gas)

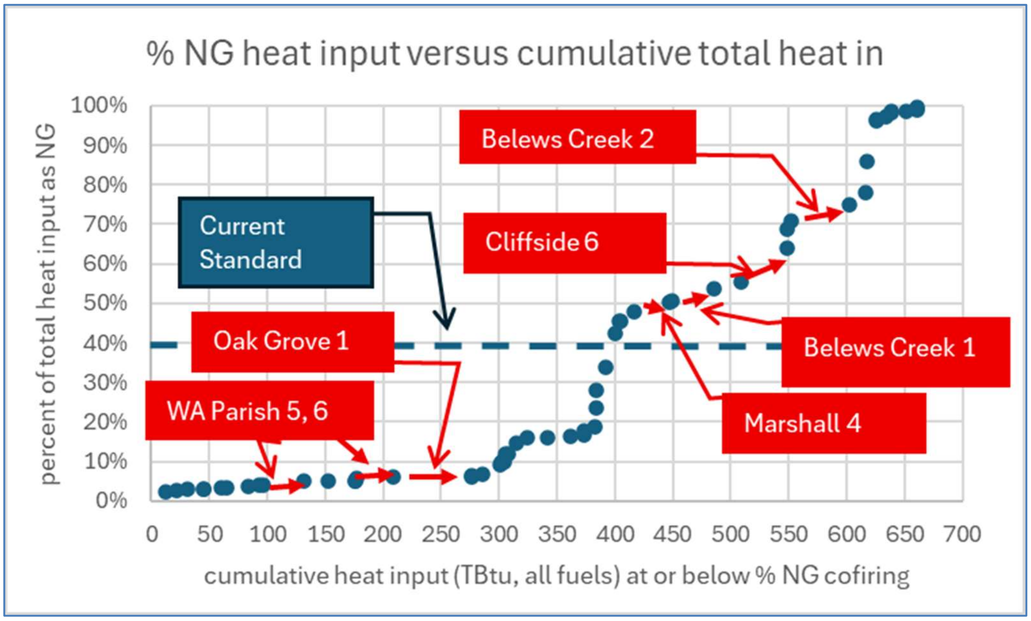
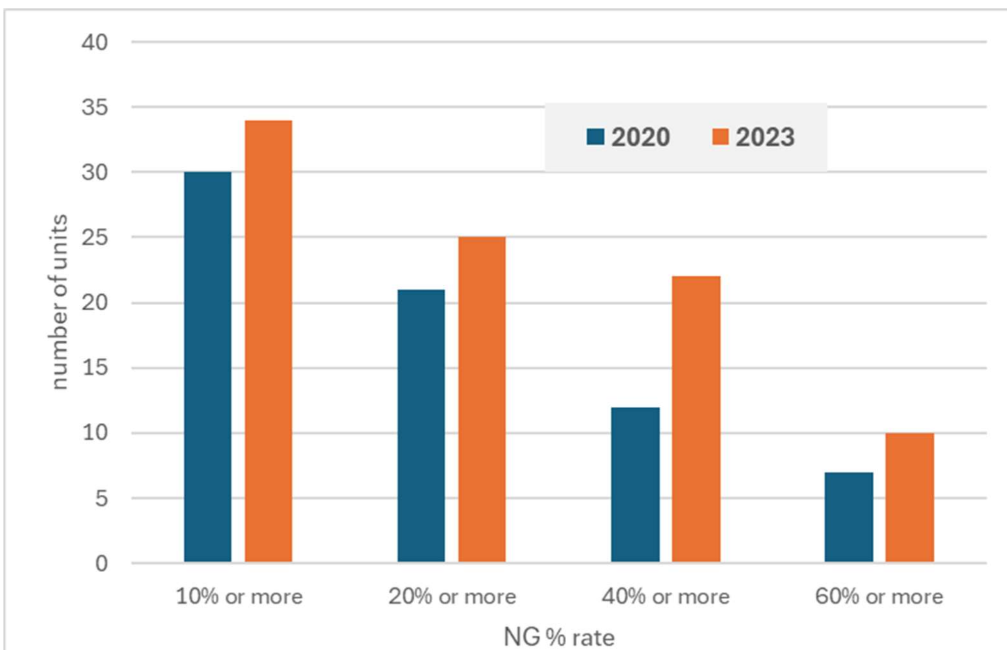


Figure 12. Number of units cofiring at a given natural gas % rate (developed from EIA Form 923 data)

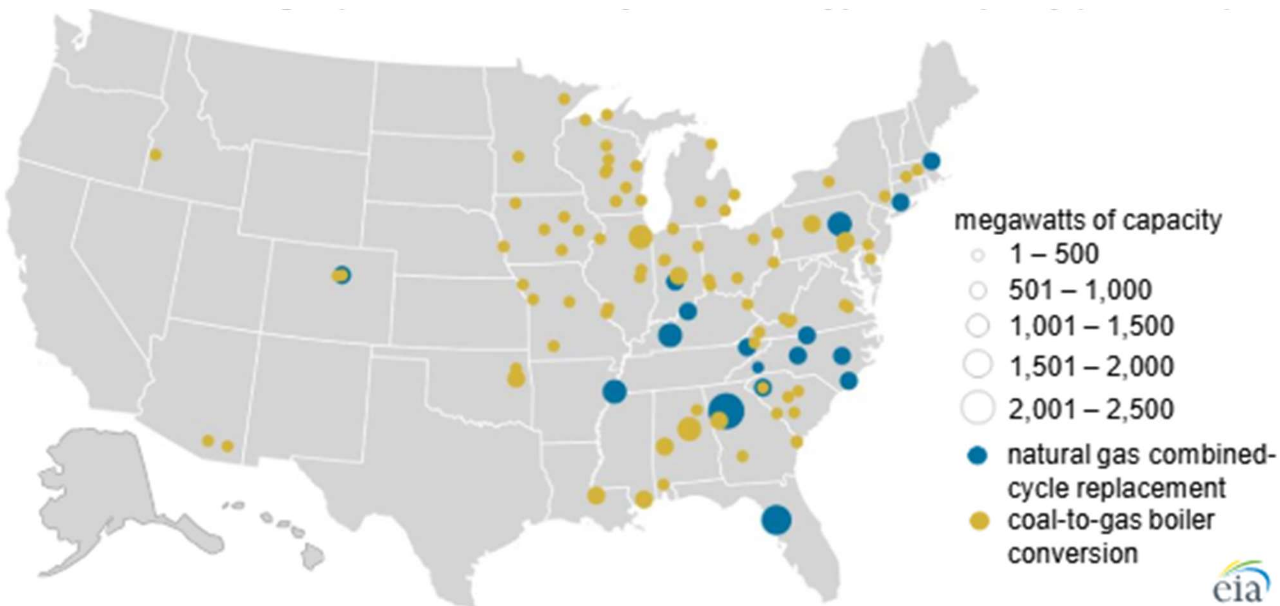


Any facility that has access to natural gas in sufficient quantities is capable of cofiring natural gas to whatever level the facility determines with the aforementioned modifications. There are some trade-offs that will be discussed in the next section. Facilities that have chosen to cofire natural gas are facilities that have chosen to take advantage of lower cost natural gas prices that resulted from the shale gas revolution and to improve operational flexibliity, while retaining the option of continuing to use coal at some level.

2.3 Current Deployment of Natural Gas Conversions

Conversions are when the boiler is configured to no longer fire coal and instead just fire natural gas. From a technical perspective, there are some additional modifications an owner may choose in order to improve the efficiency and also the emissions of the unit. As shown in Figure 13, many coal to gas conversions were performed between 2011-2019. The choice between converting a coal plant to natural gas versus replacing it with a combined cycle plant depends upon how the owner intends to continue to operate the unit. If the plan is to have a base-load unit, an owner will likely opt for a natural gas combined cycle plant. But, if the plant will be used more as a load following plant, cofiring or a coal to gas conversion may be preferable because is it far less expensive. Although complete burner replacement is an option for total gas conversion, it may not be necessary in many cases because coal burners can be modified to burn 100% natural gas.[12]

Figure 13. Coal to Natural Gas Plant Conversions, 2011-2019[13]



3 EFFICIENCY AND OTHER TRADE-OFFS

Modifying a coal-fired steam generating unit to co-fire natural gas can impact how efficient that plant is—that is, how well it turns energy in the fuel into electricity. Efficiency depends on three aspects of the plant:

- **Efficiency of the boiler** – how well the boiler converts energy in the fuel into useful, high-pressure steam.
- **Steam plant efficiency** – how well the steam plant and generator convert the energy in the high-pressure steam into electricity
- **Parasitic Loads –** the portion of the gross electricity output of the generator that is necessary to run the plant. This reduces the net electricity output.

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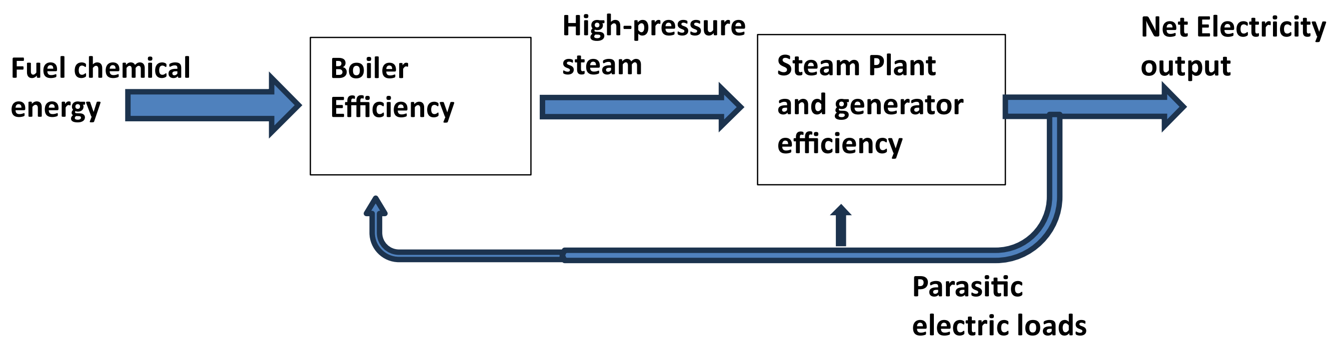
[12] https://www.power-eng.com/coal/de-bunking-the-myths-of-coal-to-gas-conversions/

[13] https://www.eia.gov/todayinenergy/detail.php?id=44636

Together, they determine the plant's **total efficiency**, and how they interact is shown in Figure 14.

Figure 14. Determinants of power plant efficiency



Boiler Efficiency

Boiler efficiency might drop slightly with the addition of natural gas because natural gas burns with a less intense (less radiant) flame than coal, which means less radiant heat transfer in the furnace. However, natural gas increases heat transfer in other parts of the boiler where air moves around more (called "convective sections"). The amount of moisture in the exhaust can affect efficiency. Natural gas creates more water vapor in the exhaust, which can lower boiler efficiency a bit, especially in an EGU burning low moisture coal like bituminous coal. If the plant uses higher moisture coal like subbituminous or lignite, this added moisture has less impact. See Staudt 2022. Table 1 shows the impact that fuel choice has on the boiler efficiency of a specific unit. In this case, 100% bituminous fuel results in a 5.6% higher boiler efficiency than 100% natural gas. 40% gas cofiring with bituminous coal would reduce boiler efficiency by about 2.24% versus 100% bituminous fuel. For Powder River Basin (PRB) fuel, the impact is significantly less. In this case, 100% PRB fuel results in a 0.6% higher efficiency than 100% natural gas. In this case, 40% gas cofiring would reduce boiler efficiency by about 0.24% versus 100% PRB fuel.

Table 1. Impact of different fuels on boiler efficiency for a specific unit.[14]

Fuel	Boiler efficiency
100% Bituminous	89.56%
100% PRB	84.4%
100% natural gas	83.92%

Steam Plant and Generator Efficiency

The steam cycle and electric generator convert the energy in the high-pressure steam to electricity output from the electric generator. This part of the plant should not be impacted by the change in fuels.

Parasitic loads

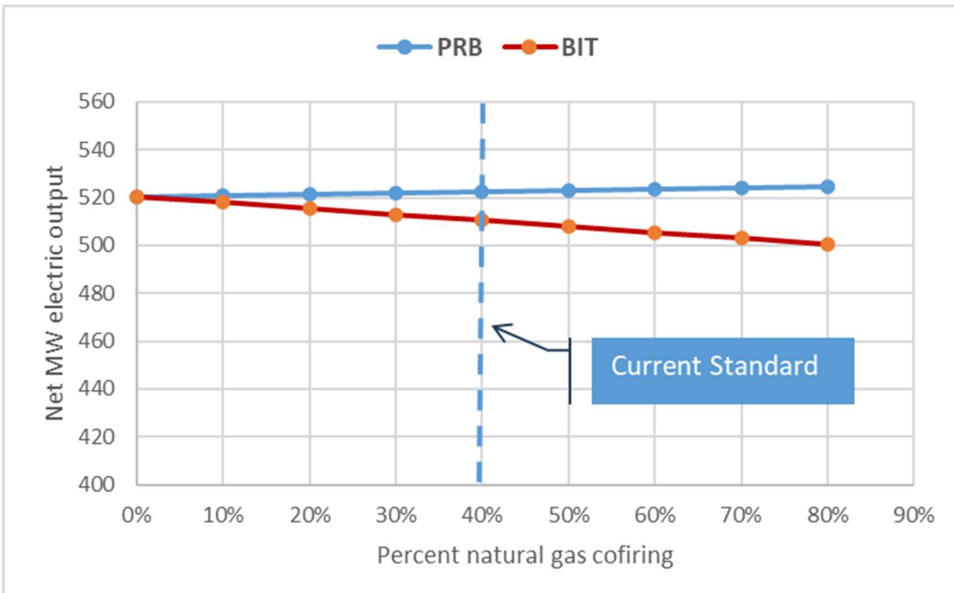
Parasitic loads (electricity needed to keep the plant operating) are reduced when cofiring natural gas. Natural gas flames don't require as much "excess air" (additional air introduced to the furnace to ensure complete combustion of fuel), which reduces the fan loads (in most cases the largest single parasitic load). Cofiring also reduces energy needed for fuel preparation (grinding of the pulverized coal is reduced),

[14] Lee, J., Coyle, M., "Leveraging Natural Gas: Technical Considerations for the Conversion of Existing Coal-Fired Boilers, 2014 ASME Power Conference, Baltimore, available at www.babcockpower.com

reduces the energy for furnace cleaning because not as much coal ash builds up, and reduces the energy used in any air pollution control equipment because gas burns cleaner than coal in terms of particulate matter, sulfur dioxide, mercury, and other pollutants.

Figure 15 shows the net result of the above effects, estimated for a hypothetical 520 MW_{net} coal fired power plant. This analysis assumes that the maximum heat input to the furnace remains the same. This analysis also incorporates the estimated combined effects of the impact of natural cofiring on boiler efficiency and parasitic loads. As shown, the estimated net impact of 40% natural gas cofiring reduces output for a bituminous plant about 10 MW (1.9%), but actually has a net beneficial effect on PRB fueled units of about 2 MW (0.38%). For any specific unit, the effects may be somewhat different. According to EIA, in 2023 263 million short tons of bituminous coal and 271 million tons of subbituminous coal (mostly PRB) was produced, and nearly all of that was used for power generation.

Figure 15. Estimated impact of natural gas cofiring on a nominal, 520 MW_{net} power plant[15]



Other improvements associated with increased natural gas cofiring include reduced maintenance due to lower wear and tear on equipment associated with coal and fly ash handling.

The following are explored in more detail in Staudt 2022.

- The increase in moisture from gas cofiring will impact boiler efficiency of bituminous coal plants somewhat. For subbituminous or lignite coal units, which have higher inherent moisture content, the impact is small.
- Flame stability is improved with gas cofiring, which also benefits operations when the plant is changing loads.
- There are improvements from gas cofiring with regard to parasitic loads that reduce plant efficiency. Combustion air fan loads, fuel preparation energy loads, and furnace cleaning energy demands are reduced with cofiring.
- Gas cofiring offers benefits when compared to a full gas conversion because some of the combustion air in a coal burner is delivered from primary air through the pulverizer. As a

[15] Determined from calculations from Staudt 2022

result, a full gas conversion might entail the need for more fan capacity while it will be unnecessary for a cofiring situation.

Therefore, since gas cofiring has both beneficial impacts on plant efficiency and in some cases adverse impacts on plant efficiency, the exact impact will depend upon the particular unit. In some cases, the overall impact of cofiring on efficiency could be negative, and in other cases the overall impact may be positive. In any situation, however, there are substantial benefits with regard to maintenance.

3.1 Efficiency Differences Between the Use of Gas at an NGCC and Co-Fired at a Coal Plant

A common parameter used to describe the efficiency of a power plant is heat rate, which is the amount of fuel energy needed to produce a kilowatt (kW) of electric power output. Units are British thermal units per kW, or Btu/kW.

Existing coal fired power plants have heat rates on the order of 10,000 to 11,000 Btu/kW, although a state-of-the-art ultrasupercritical[16] power plant could have heat rates on the order of 8,600 Btu/kW, and some of the most efficient coal power plants have heat rates roughly equal to this, if not better in some cases.[17]

State-of-the-art natural gas combustion turbines (aka, simple cycle gas turbines) have a heat rate on the order of 9,100-9,500 Btu/kW. Existing simple cycle plants have higher heat rates, typically well over 10,000 Btu/hr. Therefore, they have heat rates that are similar to existing, conventional coal steam plants.

State-of-the-art combined cycle power plants (a combustion turbine that is combined with a steam cycle that makes use of the energy in the hot, combustion turbine exhaust) have heat rates that will be in the range of 7,000 Btu/kW (sometimes even less), but the typical heat rate for existing combined units is in the range of 8,000 Btu/kW, with some being higher, especially when operating below full load.[18] For example, at low loads, the steam cycle may not be operating, and the heat rate will be similar to a simple-cycle combustion turbine.

Conventional steam facilities that cofire coal and natural gas have heat rates that are similar to simple-cycle gas turbine power plants (aka, combustion turbines), which are commonly used for peaking or load following. It may be more economical to co-fire at an existing coal-fired unit compared to building a new, natural gas combined cycle or simple cycle generating unit in some scenarios:

- In a load-following or peaking mode, cofiring natural gas in an existing coal fired boiler is quite likely to be economically preferable to using a simple-cycle turbine because the cost of a cofiring project is much less than that of a simple cycle combustion turbine which has a similar heat rate.
- It may also be preferable to a combined-cycle plant in load following or perhaps even base-loaded mode since the capital cost of a co-fired plant is much lower than that of a new combined-cycle plant.

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[16] This is a particular, very high efficiency steam cycle.

[17] Staudt, J., Uncontrolled Carbon Dioxide Emissions from Selected Electric Generation Units, August 26, 2016; available at: https://www.andovertechnology.com/wp-content/uploads/2021/03/C_16_2_EDF_FINAL.pdf

[18] To some degree, these are not apples-to-apples comparisons. For natural gas fired gas turbines, heat rates are typically represented by heat input using lower heating value (not accounting for heat from condensing moisture in the flue gas) and for conventional steam plants heat input is characterized by higher heating value (incorporates heat associated with condensing moisture in the exhaust gas). This may impact the heat input by 5% or so. But, for the purpose of comparing these power cycles, it is less important because the actual heat rate for a specific facility will be site specific.