Andover Technology Partners 978-683-9599
Consulting to the Air Pollution Control Industry

Natural Gas Cofiring for Coal-Fired Utility Boilers

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Executive Summary

Cofiring of natural gas with coal is not a new phenomenon for coal-fired electric utility boilers, but it is one that has taken on increasing significance in recent years. Experience with cofiring of natural gas with coal goes back several decades. As such, the technical issues associated with cofiring are well understood. Cofiring natural gas offers several benefits compared to using 100% coal: reduction of air pollutant emissions and solid or liquid waste emissions, more rapid and faster load responsiveness, increased capacity in some cases, reduction of parasitic loads, and reduced operating and maintenance costs, more fuel flexibility, just to name a few. On the other side of the ledger, utilization of natural gas can have a slight adverse impact on boiler efficiency and may also cause an increase in fuel costs. In addition, coal plants with natural gas cofiring still have a higher carbon footprint than natural gas combined cycle plants and renewables.

The purpose of this analysis is to: a) demonstrate the technical feasibility of cofiring natural gas at existing coal-fired power plants in the United States, including presenting case studies of units that cofire; b) examine engineering and other technical issues that arise when power plants undertake such projects, as well as ways in which those issues have been successfully overcome; and c) identify the range of capital and operating costs associated with such projects.

This report demonstrates that natural gas cofiring projects are technically feasible, with dozens of facilities currently cofiring that cover a wide range of boiler types, capacities, configurations, and locations, and new projects are underway. In addition, the modification requirements and associated capital costs for cofiring, even at 100%, are lower than those for a full gas conversion, in part due to more limited changes needed for the boiler. For example, compared to full gas conversion, cofiring retrofits do not require burners to be replaced (existing burners are modified) and less ductwork modifications. As noted, the technical aspects of cofiring modifications are well understood and will be discussed in this report. Using publicly available information, this study finds coal boiler unit retooling costs ranging from $47-67/kW for 40%-100% cofiring with most projects at about $50/kW.

I. Summary of study objectives

This study examined the following:

- Retooling/modification costs for coal units at various cofiring thresholds short of full conversion, including the boiler and burner equipment needed and estimated costs for that equipment.

- Technical issues related to cofiring natural gas with coal including:
  - Impact on boiler heat balance and boiler efficiency
  - Impact on furnace slagging
  - Impact on emissions of NOx, SO_2, CO, and other pollutants
  - Impact on boiler support equipment
- Impacts to operating or maintenance costs and quantification of these changes in operating or maintenance costs to the degree possible.
- The percent reduction in CO_2 emissions associated with cofiring, including interaction with other pollution controls.

The study does not examine issues relating to gas supply or any technical or economic issues outside of boilers.

II. Summary of cost estimates

The capital costs of a cofiring project include (1) those associated with on-site modifications to the boiler and combustion system, and (2) those associated with connecting plants to natural gas pipelines. Cofiring projects are significantly different than full conversions to a natural gas steam facility – cofiring projects keep coal equipment in place, including the existing burners, and primarily add gas capability to existing burners. As will be described in more detail, a complete natural gas conversion is more complex than cofiring because it involves replacing the coal burners with new natural gas burners, which will often impact other equipment as well. This analysis finds that the costs associated with cofiring projects are significantly lower than full conversions to a natural gas steam facility and lower than cofiring cost estimates that the EPA has used in the past.

This study uses publicly reported costs of cofiring projects to estimate the capital costs of boiler modifications, as opposed to studies of theoretical projects or algorithms that have been used by others. Capital costs associated with boiler modifications were collected from cofiring projects at 18 units at seven plants for which public data was available. Of these, data from six plants (14 units) were used to develop capital cost range estimates for cofiring retrofits, focusing on units capable of cofiring with natural gas input of 40% or more. This analysis excluded cost data from 4 units at the Big Bend coal plant since the retrofit for this plant was different than the other plants in this analysis as it was limited to replacement and upgrade of ignition systems and since the plant's natural gas usage was limited to 33% of rated output, but the data is shown to illustrate the difference with other retrofits. These sample units represent a significant portion of the 40 units that cofired at least 5% of their heat input as natural gas in 2020.[1] For most of these plants the costs of on-site boiler modifications were reported separately from pipeline costs.[2]

Table ES-1 displays the cofiring capital cost estimates from this study. Depending on the circumstances, the capital cost of a cofiring retrofit to fire between 40% to 100% heat input as gas is around $50/kW – with a full range of $47-$67/kW for the projects analyzed. It is important to note that modifying a unit to cofire 100% (or less) of heat input is different from fully converting a unit to natural gas.

Table ES-1. Reported capital costs of coal and gas cofiring projects, excluding gas pipeline.

	Big Bend[1]	**Marshall**	**Belews Creek 1 & 2**	**Cliffside 5 & 6**	**Brunner Island**	**Deerhaven**	**Montour[4]**
Total equipment (Million $)	10	104	117	65	110	12.5	70
Capacity (MW)	1700	2119	2240	1395	1600	228	1504
No. of units	4	4	2	2	3	1	2
Pipeline distance (mi) if included in total equipment					3		
Est pipeline cost (Million $)					3[2]		
Est boiler modification cost (Million $)	10	104	117	65	107	12.5	70
Boiler mod cost ($/kW)	6[1]	49	52	47	67	55	47
Max percent cofiring possible	33%	47%[3]	50%	75%[3]	100%[5]	100%[5]	100%[5]

[1] Modifications at Big Bend were limited to replacement and upgrade of ignition systems, while the other plants in this table involved further modifications. For these reasons, Big Bend is excluded from cost estimates but shown here for reference.
[2] Assumes a pipeline cost of $1 million per mile.
[3] These are capacity weighted percentages based upon 40% for Cliffside 5 and 100% for Cliffside 6, 40% for Marshall 1 & 2 and 50% for Marshall 3 & 4.
[4] Talen Energy announced plans in 2016 to install boiler modifications at Montour to enable cofiring capability, and estimated the plant modifications would cost approximately $70 million. Talen Energy did not ultimately go through with the modifications and Montour does not currently cofire, however the estimated costs are included because they are in the same range as the other data.
[5] Cofiring up to 100% of heat input is different than a full conversion to natural gas. Full conversion is more costly and would require more equipment modifications.

[1] EIA Form 923
[2] One plant (Brunner Island) reported only total cofiring capital costs. Pipeline costs were estimated and deducted from the total cost using an assumption of $1 million per mile, with mileage based upon reported mileage. This provides an *estimate* of the boiler modification costs. The actual cost per mile will differ based upon many factors.

For comparison, an analysis by Black & Veatch estimated a cost range of $10-100/kW for natural gas cofiring and $100-250/kW for a complete conversion from coal to natural gas.[3] The costs presented in Table ES-1 are also lower than costs that EPA has previously relied on when looking at cofiring costs. EPA estimates to date have not distinguished between retrofit costs of full conversion and the retrofit costs of cofiring. Please see Section V for more detail.

Estimates of the cost of CO_2 reduction from natural gas cofiring show it to be highly dependent on the cost differential between the price of natural gas and coal. The impact of capital cost relative to other costs will depend upon the degree of cofiring and the relative costs of natural gas and coal, with the impact of capital costs as a fraction of total costs dropping as cofiring rates increase. The cost effectiveness ($/ton of CO_2 reduced on a lb/MWh basis) was estimated for both bituminous and Powder River Basin (PRB) fueled units at an assumed 35% capacity factor. A fuel cost differential of $1.50/MMBtu ($3.50/MMBtu for natural gas versus $2.00/MMBtu for coal) results in an abatement cost in the range of $25/ton to $40/ton of CO_2 reduced (Figure ES-1). A fuel cost differential of $3.00/MMBtu ($5.00/MMBtu for natural gas versus $2.00/MMBtu for coal) results in an abatement cost in the range of $55/ton to 70/ton of CO_2 reduced (Figure ES-2). The type of coal and specifics of the unit will also impact the cost somewhat because this will impact the boiler efficiency and other effects. However, the cost differential between the fuels is, unsurprisingly, the most significant factor.

There are competing effects on the total cost of cofiring. As natural gas cofiring is increased, boiler efficiency is reduced to some degree, with increased capital costs and fuel costs on the one hand, and on the other hand, there are reduced reagent costs, lower fixed operating and maintenance costs, and reduced parasitic loads. The adverse impact of natural gas on boiler efficiency is generally greater for bituminous than for PRB units, and that will also differ based upon the ash characteristics for bituminous units. For bituminous units with furnace slag that cleans more easily, the improved furnace cleanliness when gas is fired will offset the negative impact of flue gas moisture on boiler efficiency somewhat. In such a case, increased natural gas fuel use could actually lower the cost of reducing CO_2 emission rate in a similar manner that it does for PRB fuel.

[3] https://www.powermag.com/utility-options-for-leveraging-natural-gas/

Figure ES-1. Estimated abatement cost and CO2 emissions reductions associated with natural gas cofiring for PRB and bituminous. Cost of natural gas is assumed to be \$3.50/MMBtu versus \$2.00/MMBtu for coal.

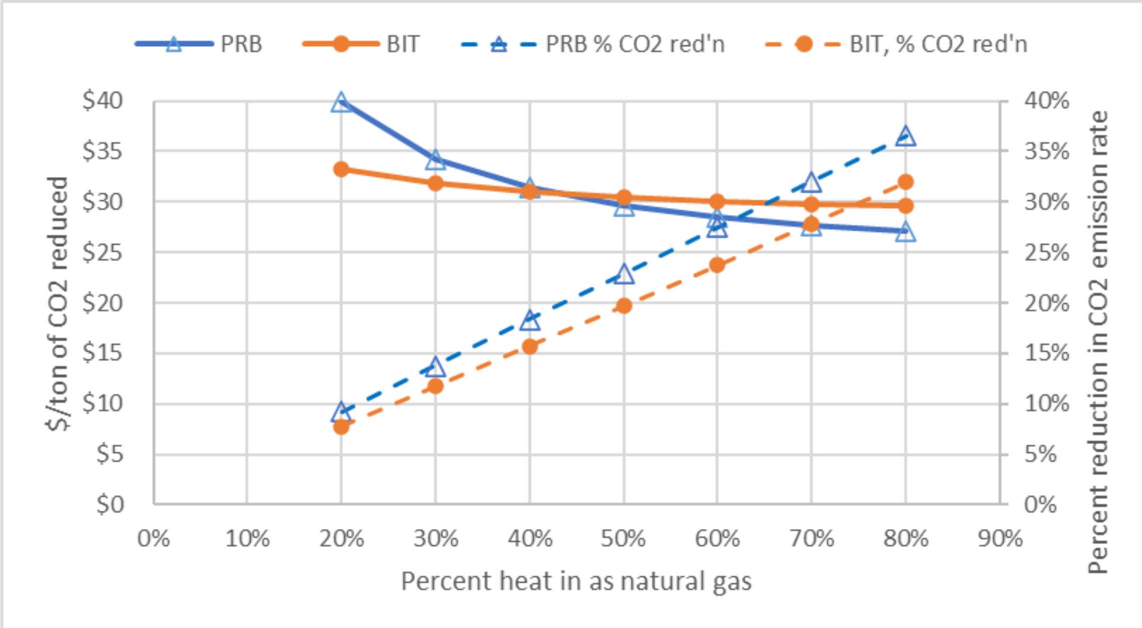


Figure ES-2. Estimated cost of reducing CO2 emissions with natural gas cofiring for PRB and bituminous coals and percent CO2 reduction - \$/ton of CO2 reduced versus percent natural gas heat input. Cost of natural gas is assumed to be \$5.00/MMBtu versus \$2.00/MMBtu for coal.

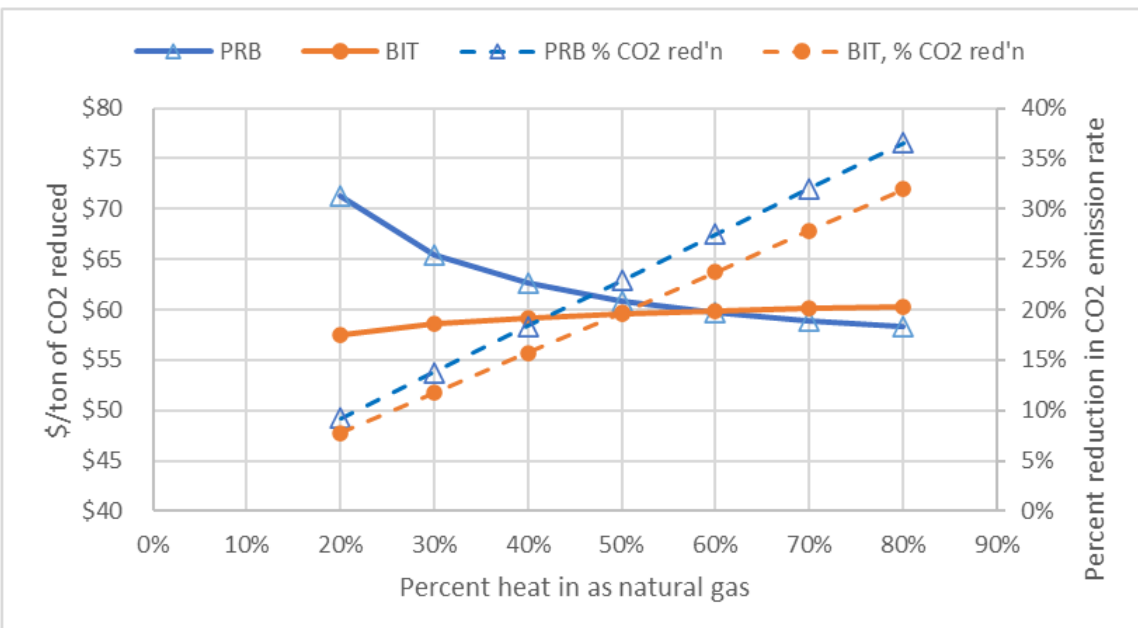
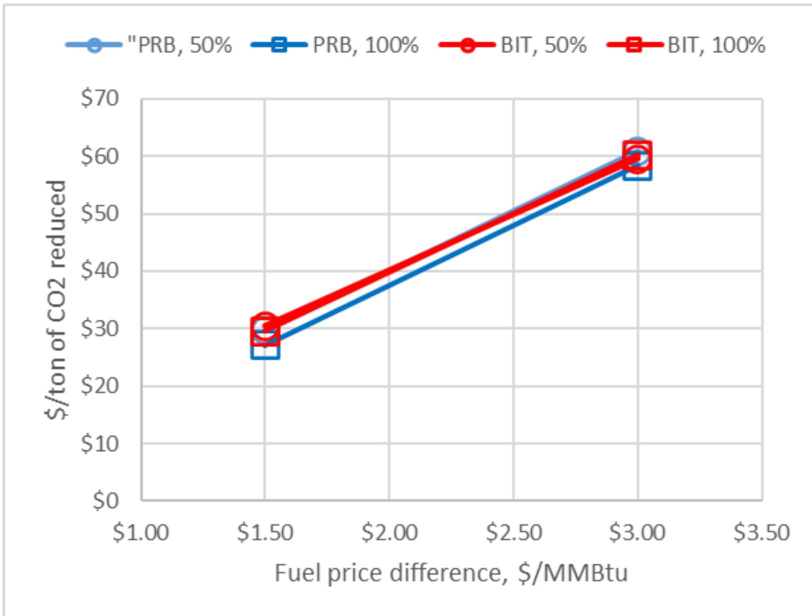


Figure ES-3 shows that the cost per ton of CO_2 reduced is most impacted by the cost difference between natural gas and coal, rather than factors like coal type or level of cofiring But, reductions in parasitic loads and reductions in O&M reduce the impact of fuel cost from what it would otherwise be.

Figure ES-3. Effect of fuel price differential on CO_2 abatement cost for 50% gas cofiring and 100% gas firing



SO_2, mercury, PM and NOx emissions will also be reduced with increased natural gas cofiring. SO_2, mercury and PM emissions will be reduced approximately at the same rate as the level of cofiring (i.e., 50% cofiring will reduce SO_2 emissions by roughly 50%) and NOx emissions will generally drop, but by a level that will be determined by the specifics of the situation.

Study Results

I. Introduction

Natural gas combustion is primarily used in gas turbine applications for power generation, with coal being the dominant fuel for fueling utility boilers. Recently, in response to increased availability of natural gas, somewhat more stable natural gas pricing, increased use of coal units in a load-following mode, and environmental requirements for coal plants, some power plant owners have started cofiring with natural gas or fully converting to natural gas. Andover Technology Partners previously addressed natural gas conversions in a 2014 report.[4] This new report addresses natural gas cofiring in coal-fired utility boilers. Natural gas has the following advantages over coal when cofired with coal in a boiler:

- Wider and faster boiler turndown (faster ramping up and down), which is advantageous for load following.
- In some cases, higher maximum capacity. Some boilers that originally were designed for bituminous coal and then started using PRB coal lost capacity due to limitations in the fuel processing equipment, or other limitations, and the lower heating value of the PRB coal. Natural gas cofiring can restore lost capacity in those cases.
- Generally, somewhat lower NOx emissions will result and a reduction in SO_2, PM, and mercury emissions that is in direct proportion to the amount of natural gas fired in lieu of coal.
- Lower maintenance costs – Due to reduced slagging or boiler fouling in the furnace, reduced fly ash build up in the ductwork and PM capture devices, reduced need to pulverize and transport solid fuel, and reduced use of air pollution control reagents, operation and maintenance costs are reduced when cofiring gas rather than 100% coal. For full gas conversions, operating and maintenance costs could be reduced by as much as 50%,[5] with cofiring somewhat less than this. For the purpose of this study, it is conservatively assumed that fixed O&M drops by up to 10% when cofiring up to 100% and this is proportional to the degree of cofiring.
- Improved fuel flexibility – As a result of lower coal use, it will be possible to purchase coals

[4] Andover Technology Partners, *Natural Gas Conversion and Cofiring for Coal-Fired Utility Boilers*, for Environmental Defense Fund, November 30, 2014

[5] UBS Investment Research Coal to Gas Plant Conversion Conference Call Transcript, Interview with Angelos Kokkinos of Babcock Power, May 29, 2013

that might otherwise be more problematic from a furnace cleanliness or emissions perspective. The resulting coals may be less costly on a dollar per Btu basis.

- Lower parasitic loads – Reduced electricity demand for fuel preparation (coal transport, crushing, pulverizers, etc.) and reduced electrical demand from air pollution control equipment will reduce parasitic loads. This will result in an increase in net output.
- Lower CO_2 emissions per unit of heat input and per unit of electricity produced – Natural gas combustion results in roughly 55-60% of the CO_2 emitted per unit of heat input as compared to coal. Natural gas may reduce boiler efficiency which increases heat rate somewhat, but this is more than offset by the much lower CO_2 emissions of natural gas.

The principal disadvantages of natural gas as a fuel are:

- Generally higher cost than coal per Btu of heat input, depending upon the specifics of the location.
- Depending upon coal characteristics, lower boiler efficiency may result due to the increased moisture level in the exhaust gas. This will vary based upon the fuel being used and the particulars of the unit. For example, the impact is greater for bituminous fuel because bituminous fuel has lower moisture content than subbituminous or lignite. One study indicated boiler efficiencies as shown in Table 1 for firing different fuels in the same unit. It is important to note that a unit designed for a specific fuel will generally achieve better boiler efficiencies than a boiler where the fuel has changed from the design fuel. Nevertheless, this table shows that the impact is greater for bituminous coals than for PRB coals.
  Other effects will impact this, such as the nature of the boiler slagging, discussed further below.

Table 1. Impact of different fuels on boiler efficiency for a specific unit.[6]

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

- The heat release in the furnace is impacted. On the one hand, lower emissivity of a natural gas flame will reduce heat transfer in the furnace. On the other hand, less slagging in the furnace will improve heat transfer in the furnace and improve boiler efficiency. These can impact

[6] 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

furnace exit gas temperature.

- Unlike coal, natural gas is not stockpiled at the plant and is also used for residential and other services – increasing the risk of supply disruption. The risk of having service interrupted during periods where residential demand is high may be addressed with firm, uninterruptible service. However, this may entail purchasing the natural gas at a higher cost.

The following sections of this report will discuss:

- The background on use of natural gas and cofiring in power generation boilers
- Description of the modifications necessary to co-fire natural gas or to convert to 100% natural gas firing and boiler impacts
- Examples of cofiring natural gas
- Costs and impact on emissions

II. Background on Use of Natural Gas and Cofiring in Power Generation Boilers

Coal fired boilers will typically start up on either natural gas or oil. Boilers start with gas igniters that heat up the furnace and allow ignition of the coal. Use of natural gas in this manner is therefore generally limited to low loads. Many igniters are also not designed for the temperature conditions at high loads, so at high loads igniters must be retracted and cannot be used for cofiring. Therefore, many boilers already cofire gas, but only for start up.

Interest in cofiring of natural gas at higher loads increased in the 1980s and 1990s with emphasis on reducing NOx or SO_2 emissions from coal-fired boilers. When cofiring, gas may be admitted into the coal burner region (typically in a "cane" or fuel gun in the secondary air annulus of the burner), or it may be admitted downstream of the coal burners. One approach to reduce NOx emissions by co-firing is through a process known as natural gas fuel reburn, where natural gas is fired downstream of the primary combustion zone – typically at a point downstream of the coal burners.

A 2014 study by Andover Technology Partners found nearly 40 coal to gas conversions had been performed and examined 17 case studies to show that these conversions occurred on a wide range of boilers, fuel types, and boiler sizes.[7] EIA determined in 2020 that over 100 coal power plants had been replaced or converted to natural gas.[8] In addition to these sites, natural gas reburning was deployed commercially for NOx control at the CP Crane station near Baltimore, and the TVA Allen unit 1 in 1998. These reburning systems were later taken out of service as NOx emission regulations became more stringent and other, more effective, NOx reduction technologies were deployed at these plants. Gas cofiring has also been deployed at dozens of sites, some of which will be examined in more detail later in this report. As experience demonstrates, the technology to convert a coal unit to natural gas or co-fire natural gas in a coal unit is well established. The technology will be discussed in more detail later in this report.

A. Natural Gas Co-firing Experience

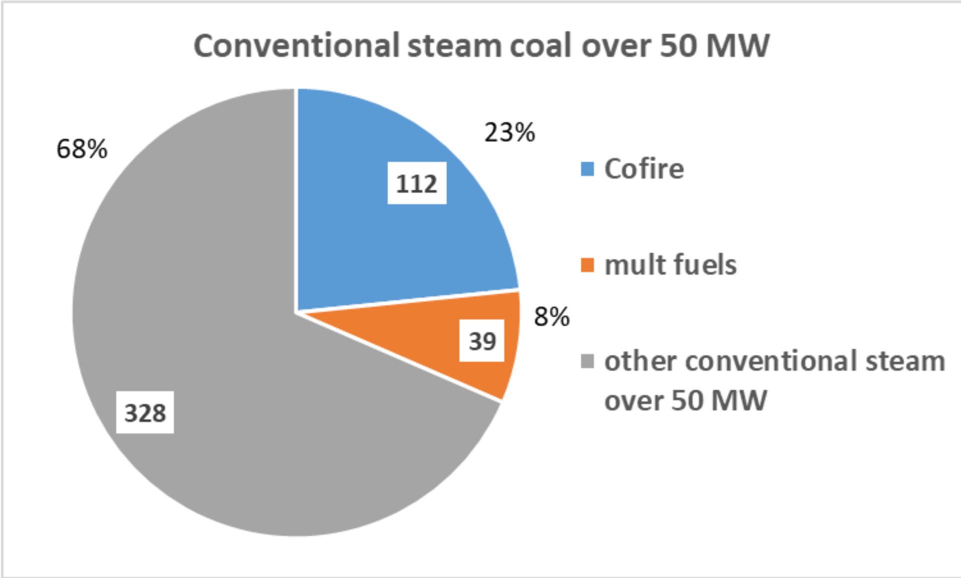
Because gas cofiring and conversion have been carried out for many years, the technical issues regarding modifications to the boiler are fairly well understood. With regard to deployment at a specific site, the boiler and combustion system modifications for cofiring can be completed in no more than 18 months, and generally much less for less complex retrofits. The schedule may be more limited by the changes needed to supply additional natural gas to the facility, which may require getting rights of way for the connections to natural gas pipelines. The issue of natural gas supply will not be examined in this report.

Cofiring natural gas and other fuels with coal is used in a significant number of facilities, although to varying degrees. According to the U.S. Energy Information Administration's Form EIA-860, of the 479 conventional steam coal units over 50 MW operating in 2020, 112 were reported to be cofiring fuels (Figure 1). Multi-fuels, as shown in Figure 1, could include other fuels, such as biomass, landfill gas or petroleum coke, that are fired with coal, gas, or oil. This data shows how the facilities are equipped, but does not address to what degree they utilize different fuels.

[7] Andover Technology Partners, *Natural Gas Conversion and Cofiring for Coal-Fired Utility Boilers*, for Environmental Defense Fund, November 30, 2014

[8] https://www.eia.gov/todayinenergy/detail.php?id=44636, by the end of 2019 14.3 GW of capacity had the boiler converted to burn natural gas and 15.3 GW of coal capacity was retired and replaced with natural gas combined cycle.

Figure 1. Conventional steam coal units over 50 MW, by fuel use (Form EIA-860 with 2020 data))



Looking at Form EIA-923 (which includes fuel use data), over 218 units used some natural gas as well as coal in 2020.[9] Most of these units used gas primarily as a start-up fuel, or for other limited use. Eliminating industrial or commercial facilities that reported to EIA Form 923, and then sorting for natural gas use, 40 electric utility[10] units had 5% or more of their total heat input for the year 2020 from natural gas. This is shown in Figure 2. This figure demonstrates that nearly 15 utility units cofired with both natural gas and coal with over 30% of the heat input from natural gas, nearly 20 utility units cofired natural gas and coal with over 20% of the heat input from natural gas, and about 30 utility units cofired natural gas and coal with 10% or more of their heat input from natural gas.

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[9] This number does not include conventional steam units that burned 100% natural gas in 2020, regardless of whether or not they continued to have the equipment to burn coal.

[10] Utility units includes those indicated as Electric Utility or NAICS-22 in EIA Form 923

Figure 2. Number of units with 5% or more natural gas heat input on an annual basis (developed from Form EIA-923 with 2020 data)

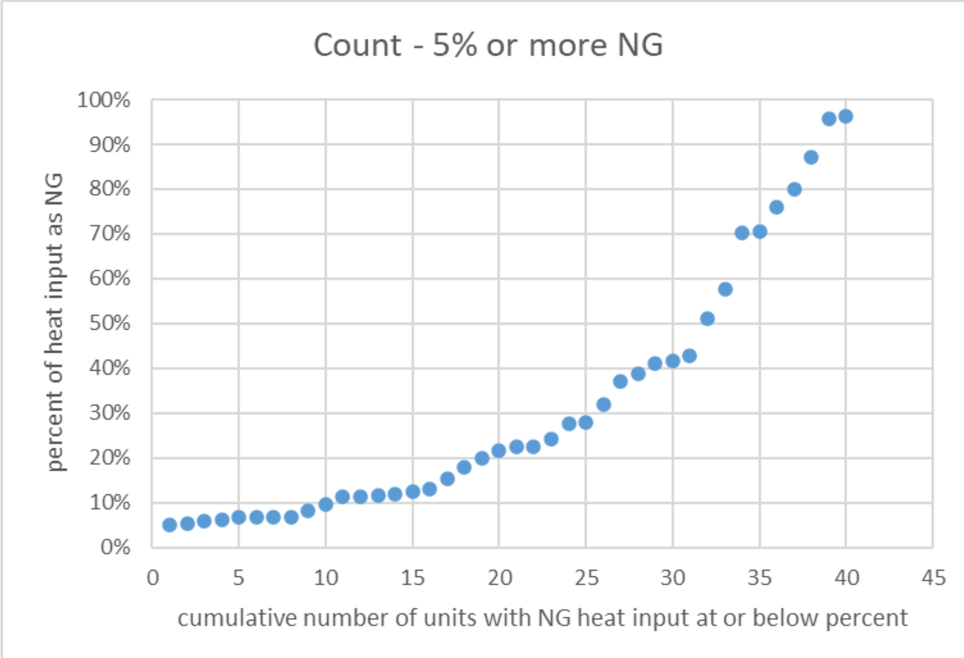
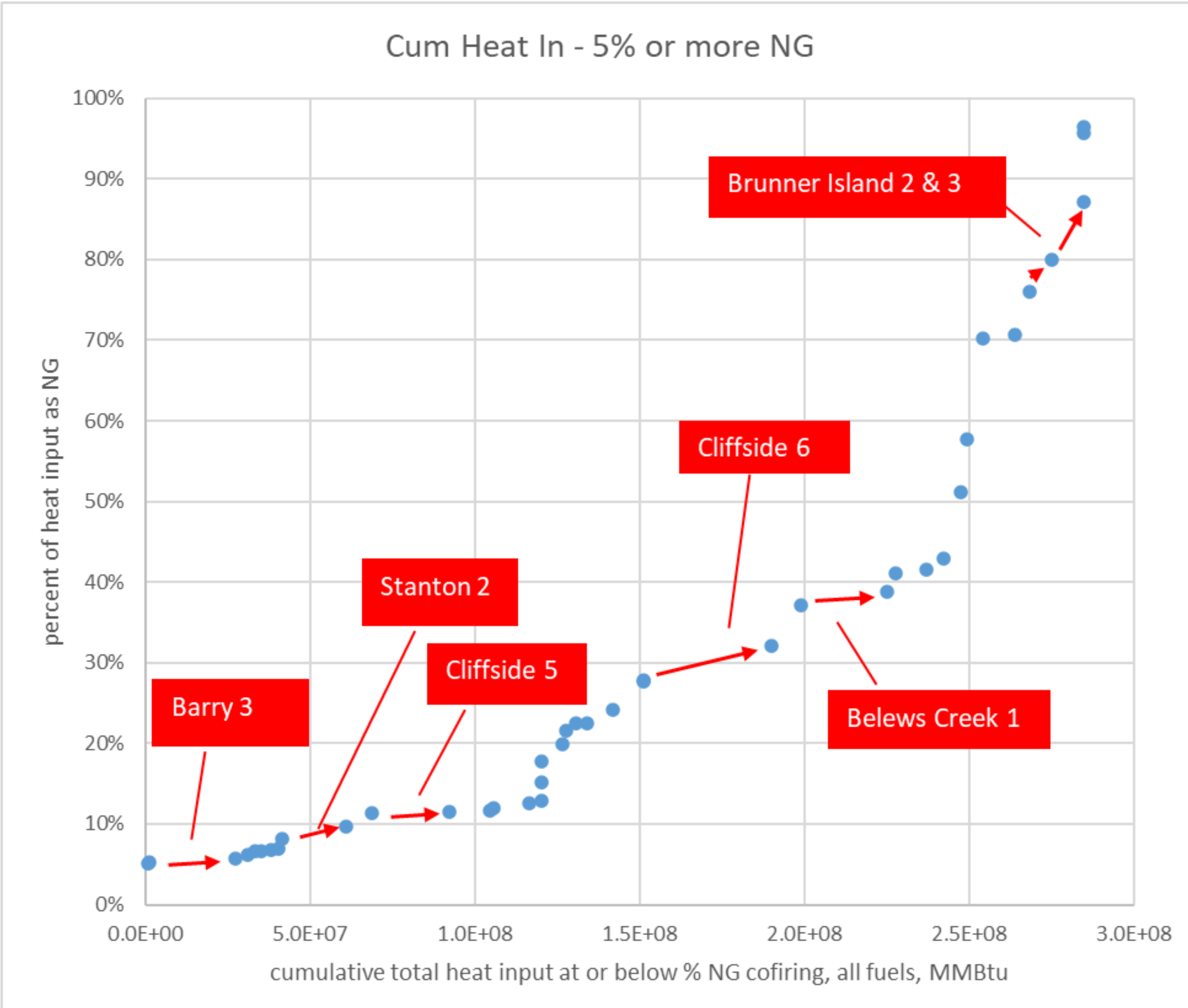


Figure 3 looks at the units that utilized natural gas for over 5% of their fuel in 2020 another way. Plotted on the horizontal axis is total, cumulative heat input from all fuels for units with percent heat input of natural gas at or below the plotted value (only including those units with 5% or more natural gas use). The amount that the data point moves to the right is indicative of the total fuel burned at the particular unit for that year. This helps to identify large units that use a great deal of fuel and may also cofire. For example, indicated on this figure are two large units that cofired a substantial amount of natural gas over the year – Cliffside 6 (aka, James Rogers Energy Center unit 6, 32.03% cofiring) and Belews Creek unit 1 (38.8% cofiring). The fact that two, very large and highly efficient coal units[11] cofire significant amounts of natural gas is indication of the advantages of cofiring in today's electric power market, even for very efficient coal units. In fact, Cliffside 6 is less than ten years old. It was built to be a flagship, efficient, modern coal unit. Belews Creek has also been a flagship plant since its construction in the 1980s.

[11] Both of these facilities were featured as examples of facilities with low CO_2 emissions in, Andover Technology Partners, *Uncontrolled CO2 Emission Rates From Selected Electric Generating Units*, for Environmental Defense Fund, August 26, 2016. CO_2 emission rates (lb/MWh) are proportional to heat rate, which is an indicator of (inverse of) efficiency.

Figure 3. Cumulative total heat input (all fuels) for units with 5% or more natural gas heat input on an annual basis (developed from 2020 EIA form 923)



III. Gas Cofiring – Modifications and Impacts

Many boilers start on natural gas and have the ability to burn up to about 10% of maximum heat input from natural gas simply for the purpose of igniting the coal. These boilers have igniters designed for low loads and low natural gas injection. To cofire natural gas with coal beyond what is possible with startup igniters entails burner modifications that are generally modest and will often involve addition of gas canes or guns to existing coal burners. These gas canes/guns are similar to igniters, but are designed for higher flows (similar to Class 1 igniters). They are typically installed in the secondary air annulus of the existing coal burner (for wall-fired boilers) or in corners for tangential units. In this respect, the cost of these modifications with respect to equipment are roughly in proportion to the amount of gas to be cofired, as more or larger gas guns are installed to increase the amount of gas that is cofired. Some changes to controls and flame safety systems may be necessary as well. Pressure part modifications to the boiler should not be necessary for gas cofiring.

Other modifications may be needed to address some of the impacts of cofiring on boiler operation, but in general, incorporation of cofiring is less complex than a full natural gas conversion, as will be discussed further.

A. Cofiring impacts on boiler operation

In designing for cofiring, boiler engineers strive to meet three key objectives

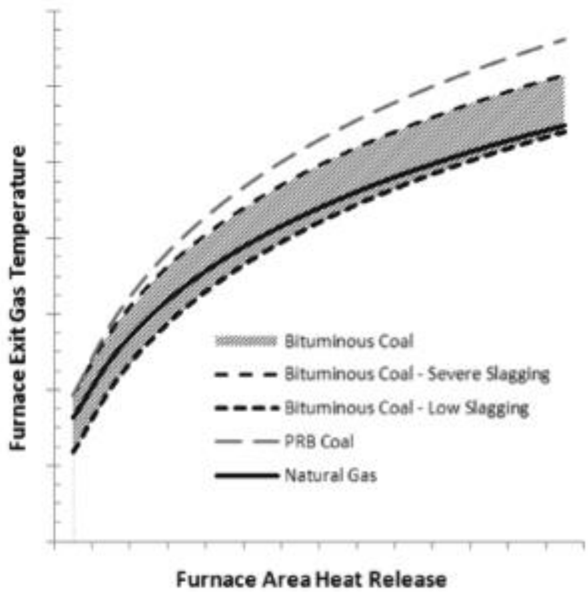
- Meet boiler efficiency goals
- Meet steam temperature requirements
- Meet emissions requirements

These are important objectives that the major boiler companies understand how to meet. Some situations may require different approaches than others, and the right approach is determined by the specific impacts of gas cofiring on boiler operation. Some of these impacts on boiler operation are beneficial, and some are not, as discussed below:

- First, cofiring increases the moisture in the exhaust versus bituminous coal flames, which impacts boiler efficiency. For high moisture coals (PRB or lignite), the impact of gas in this respect is small.
- Flame stability is improved when cofiring and therefore turndown is greater and faster. This has become an advantage as coal units have shifted to be more load following or cycling, rather than base load resources.

- Cofiring changes the heat transfer characteristics of the furnace because the gas flame is less luminous and shorter in length, which might result in higher furnace exit gas temperatures, will impact steam temperatures and may adversely impact steam generation. This is a bigger issue for furnaces firing coals that foul more or have reflective ash, such as PRB coal. This can be managed to a degree with furnace cleaning. In tangentially fired furnaces, this can also be addressed to a large degree by tilting the burners. In some cases, there may be a need to adjust attemperation spray flows. Another technique that can be used to manage exit temperature is flue gas recirculation (FGR). Some coal facilities were originally built to utilize FGR and have the ductwork in place to do it with minor modifications.
- Although the gas flame is less luminous, the higher moisture content of a natural gas flame makes the flue gas more emissive. This can have a net positive impact on heat transfer, especially in convective sections where the impact of flame luminosity is less important and gas emissivity is more significant.
- The impact of a full gas conversion on furnace exit gas temperature (FEGT) is shown in Figure 4 as a function of furnace heat release (heat input per square foot of furnace area) and fuel. As shown, depending upon the slagging characteristics of the bituminous coal, gas may result in a higher or lower FEGT for a given coal. In the case of a full gas conversion, FEGT will drop for a PRB coal fired unit (a unit originally designed for PRB, meaning it is a larger furnace). Furnaces with higher heat release per unit of area will, as expected, have a higher FEGT. This figure shows the significance of these factors for different fuels. However, in a cofiring mode some of the trends shown here will differ because there is still some furnace slagging when cofiring and the coal flame will retain a significant amount of emissivity. Further, for bituminous units with more friable boiler deposits, the impact of natural gas on reducing deposits will improve furnace heat transfer and offset to some degree the impact of the reduction in flame luminosity.

Figure 4. Impact of fuels on furnace exit gas temperature as a function of heat input per furnace area[12]



- Supercritical boilers in fact are easier with regard to gas cofiring as compared to subcritical boilers. EIA Form 860 shows that in 2020 there were 107 supercritical conventional steam coal units over 50 MW. These are large units, with average nameplate capacity of 758 MW and total capacity of over 81,000 MW. Subcritical boilers rely upon natural circulation to generate steam. EIA Form 860 shows that in 2020 there were 484 subcritical conventional steam coal units over 50 MW.[13] On average, these are not as large as supercritical units, with average nameplate capacity of 478 MW and total capacity of over 231,000 MW. For subcritical units, steam generation and furnace firing are closely related and impact steam temperature. For supercritical boilers, firing and steam generation can be independently controlled to a greater degree, which permits better control of steam temperature. Therefore, as cofiring will change somewhat the balance of heat transfer between the furnace and convective section, all other things being equal, this can be addressed more easily in a supercritical "once through" boiler.

[12] 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

[13] This includes a small number of coal fired boilers at industrial sites that supply the electric grid.

- Cofiring reduces the amount of excess air necessary for the fuel by a significant amount. Excess air in a natural gas flame is about 8%-10% compared to 15%-20% for a coal flame. Cofiring at a level of 50% will reduce excess air levels by close to 30% which can have some beneficial impacts on forced and induced draft power demands – about a 3%-4% reduction in fan demand.
- Cofiring versus a full conversion allows the advantage of continued use of primary air. Roughly 20-30% of the combustion air comes in with the coal in the form of primary air. Were the primary air fan to be lost in a full natural gas conversion, it might be necessary to increase the capacity of the forced air fan. This is an advantage of cofiring versus a full gas conversion. This is also a factor to consider in a gas conversion when a tri-sector air preheater exists. It may impact operation of the air preheater if primary air is lost and all combustion air must be delivered by the forced draft fan – increasing pressure drop across the air preheater.

Finally, boiler manufacturers and suppliers of combustion systems are well-versed in the issues regarding natural gas cofiring. They understand how to design gas cofiring systems that address the many unique situations that exist in the coal fleet. As noted by Andover Technology Partners, [14] the time frame for the boiler modifications for a full gas conversion is 18 months or so, including engineering, procurement, installation and commissioning. A gas cofiring project would be significantly less because it is less complex. So, in most cases a year or less is necessary for engineering, procurement, installation and commissioning. This does not factor in any time associated with increasing natural gas fuel supply.

If installations were more widespread, that might increase the time frame somewhat for these projects, primarily due to scheduling of labor and other resources. Experience has shown that industry has consistently responded to these requirements, and cofiring is a much less resource and labor intensive activity than past retrofit efforts.[15] So, more widespread retrofit to cofiring could be performed within a few (perhaps three) years.

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[14] As noted in Andover Technology Partners, *Natural Gas Conversion and Cofiring for Coal-Fired Utility Boilers*, for Environmental Defense Fund, November 30, 2014, the boiler modifications for a full gas conversion is 18 months or so. A gas cofiring project would be significantly less.
Also, see: UBS Investment Research Coal to Gas Plant Conversion Conference Call Transcript, Interview with Angelos Kokkinos of Babcock Power, May 29, 2013
[15] https://www.andovertechnology.com/wp-content/uploads/2020/07/9_2002_Update_12152011.pdf

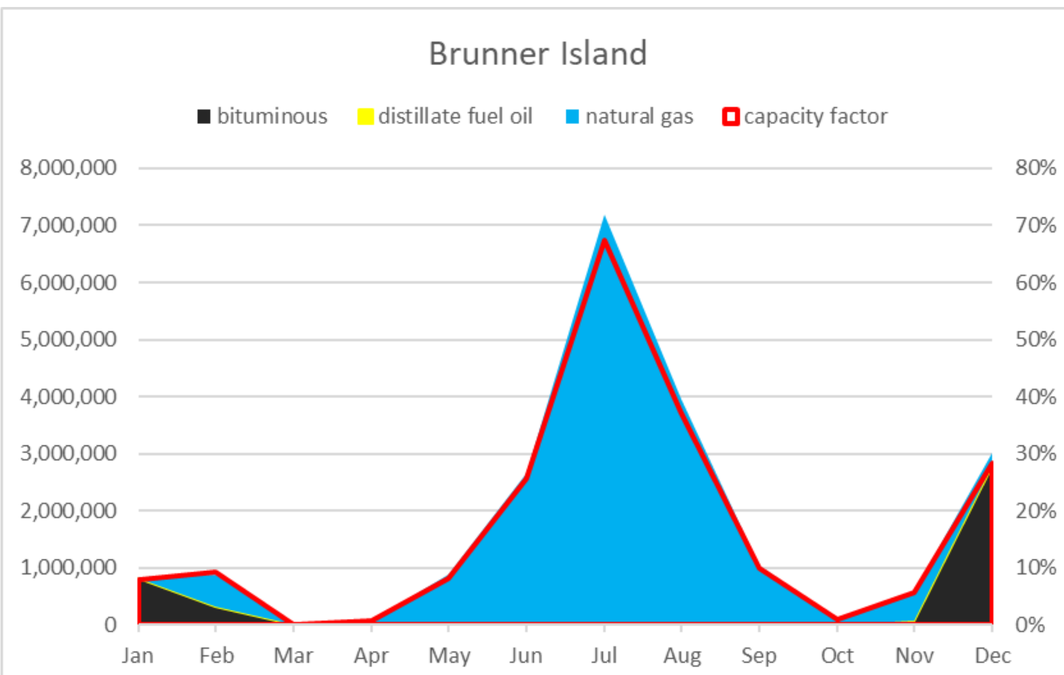
IV. Examples of cofiring natural gas

The following section provides some examples of coal-fired power plants cofiring with natural gas and the associated costs, when available. These plants were selected because their rate of cofiring was fairly significant – in most cases over 20% - and, while they are all large utility units, they cover a range of boiler sizes. Most of these facilities show a wide range of operation, indicating that they are not base-loaded, but rather follow the load. In principle, these units could be base loaded, if the load was there for them. There is no technical reason preventing a cofired unit from operating as base loaded. However, natural gas cofiring is advantageous for load following. In addition to showing monthly fuel usage over the year, estimated capacity factor is shown based upon reported maximum heat input for the furnace from the facility characteristics and air markets program data. Capacity factors, for the most part, demonstrate that the units are not base loaded, but are responding to changes in load.

Brunner Island

The Brunner Island power plant in Pennsylvania has three units with a total nameplate capacity of 1615 MW (363 MW, 405 MW, and 847 MW). It originally used oil as a startup fuel. Between 2016 to 2017 the three units at Brunner Island were modified to burn up to 100% natural gas or coal to take advantage of lower natural gas prices, as the plant is located close to the Marcellus shale region. The total cost of the project was estimated to be about $110 million (roughly $68/kW) including construction of a 3-mile-long pipeline to connect to the Texas Eastern pipeline and retrofitting of existing oil igniters in the coal-fired boilers to natural gas to cofire gas.[16] The cost of the pipeline versus boiler retooling was unavailable. Figure 5 shows fuel use over each month of 2020. As shown, over the summer months Brunner Island burned exclusively natural gas and only burned coal in the winter months, with natural gas providing roughly 87% of total heat input over the year. Its owner, Talen Energy, recently committed to phase out coal by 2028 even though Brunner Island.[17]

Figure 5. Fuel usage per month (MMBtu) by fuel in 2020 for Brunner Island



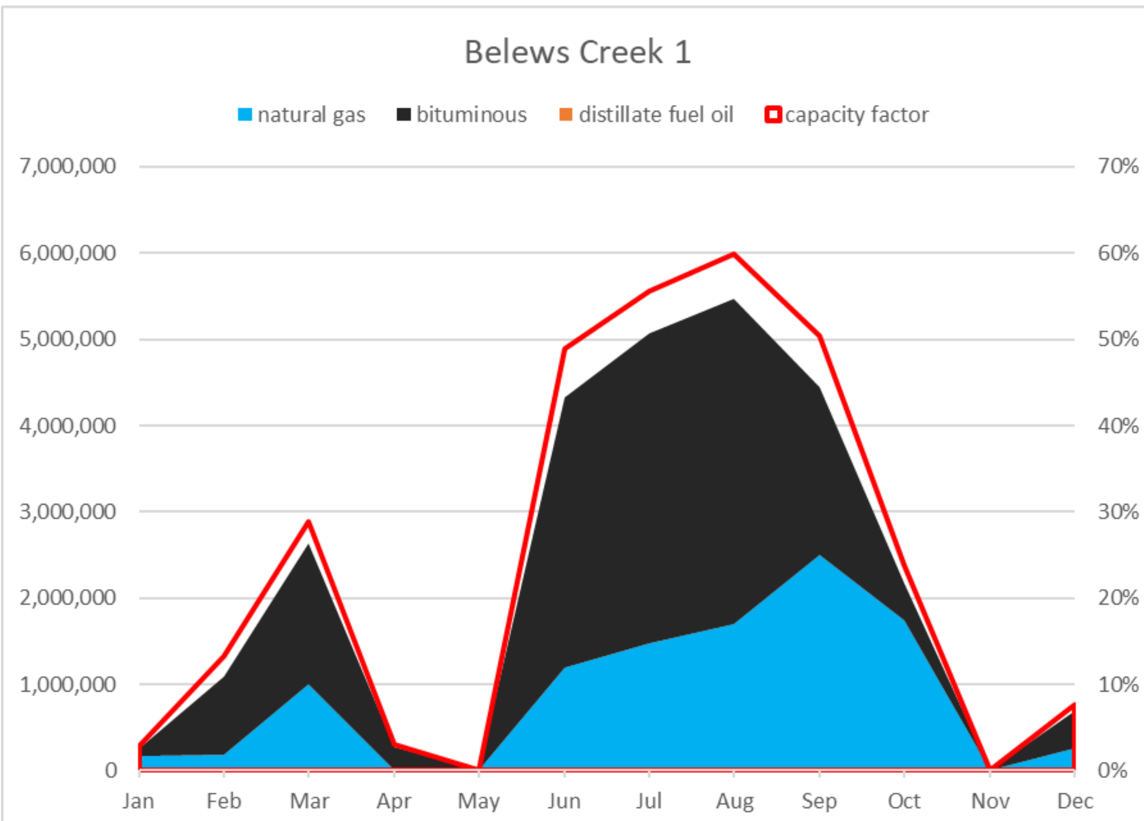
[16] Talen Energy, Barclays CEO Energy-Power Conference, September 8, 2015 and Talen Energy 10K for year 2015: https://www.sec.gov/Archives/edgar/data/1622536/000162253616000111/tln-20151231x10k.htm

[17] https://lancasteronline.com/news/local/much-criticized-brunner-island-power-plant-to-phase-out-coal-in-settlement-with-environmental-group/article_e342b75e-119b-11e8-816d-0bf8a35f5572.html

Belews Creek

Duke Energy's 2,240 MW Belews Creek 1 & 2 were retooled to cofire natural gas, with unit 1 completed in January 2020 and Unit 2 in early 2021. Both units are able to cofire up to 50% natural gas. The project cost a total of $117 million for the two units,[18] or about $52/kW, for the boiler on site work (pipeline cost was separate). Figure 6 shows fuel usage in 2020 at Belews Creek unit 1. A total of roughly 39% of the fuel input over the year was from natural gas. According to EIA's energy infrastructure map, the nearest interstate pipeline is roughly 10 miles away.

Figure 6. Fuel usage per month (MMBtu) by fuel in 2020 for Belews Creek unit 1

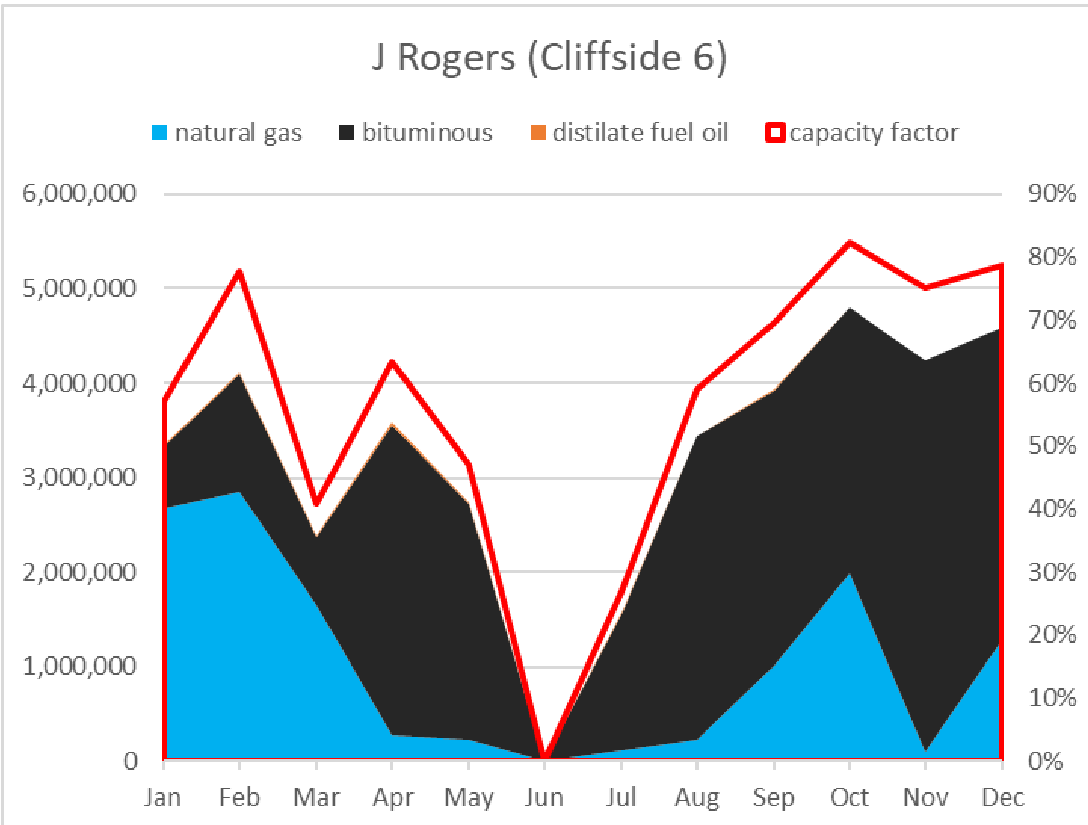


[18] https://www.bizjournals.com/charlotte/news/2018/11/19/duke-energy-wrapping-up-65m-gas-co-firing-project.html
https://www.ncwarn.org/2021/04/duke-spending-283m-on-retrofitting-coal-plants/

Cliffside

Duke Energy's 825 MW Cliffside 6 and 570 MW Cliffside 5 were modified to cofire natural gas in 2018. Unit 6 is able to burn up to 100% natural gas, and Cliffside 5 is able to burn up to 40% natural gas. The project cost a total of about $65 million,[19] or about $48/kW for the boiler modifications (excluding the pipeline cost) at a capacity-weighted average cofiring rate of up to 75% of capacity.[20] Figure 7 shows fuel usage in 2020 at Cliffside 6, a modern coal unit that was placed in service in 2013. A total of roughly 32% of the fuel input over the year was from natural gas. Using EIA's energy infrastructure map, the nearest interstate pipeline is 15-20 miles away.

Figure 7. Fuel usage per month (MMBtu) by fuel in 2020 for Cliffside 6



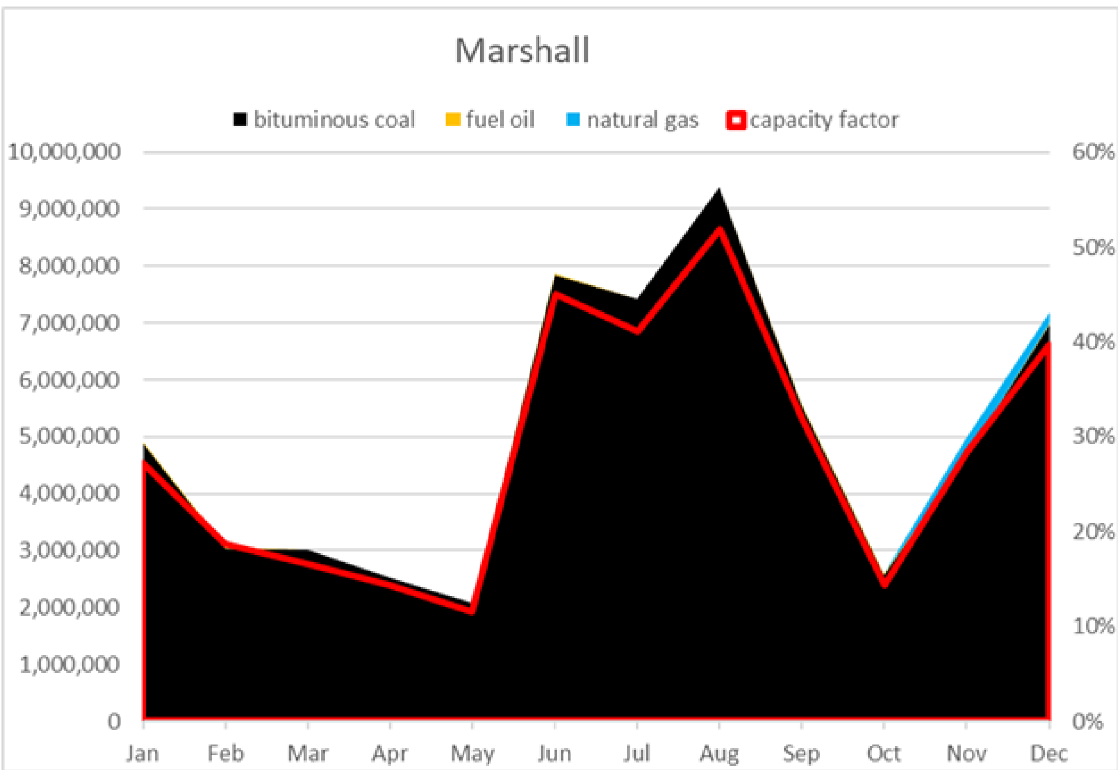
[19] Downey, J., "Duke Energy wrapping up $65 million gas cofiring project for its Cliffside coal units", *Charlotte Business Journal*, November 19, 2018
https://www.bizjournals.com/charlotte/news/2018/11/19/duke-energy-wrapping-up-65m-gas-co-firing-project.html
[20] Because the cost was reported for both units rather than per unit, a capacity-weighted average was made to estimate the impact of NG firing rate on cost.

Marshall

Marshall is a 2,000 MW plant operated by Duke Energy Carolinas. Marshall units 1-4 were recently retrofitted to cofire natural gas, with the project completed in 2021. Therefore, there was very little natural gas actually burned at the facility in 2020. Units 1 and 2 (350 MW each) were equipped to burn up to 40% natural gas, while units 3 and 4 (650 MW each) were equipped to burn up to 50% of their capacity as natural gas.[21] The total cost of the retrofit for all four units was $104 million at the plant, with another $119 million spent by Piedmont natural gas on the pipeline.[22]

Fuel usage per month (MMBtu) by fuel at Marshall in 2020 is shown in Figure 8. As shown, natural gas only started being fired late in 2020 and was less than 1% of fuel usage in 2020, but is expected to increase going forward.

Figure 8. Fuel usage per month (MMBtu) by fuel in 2020 for Marshall



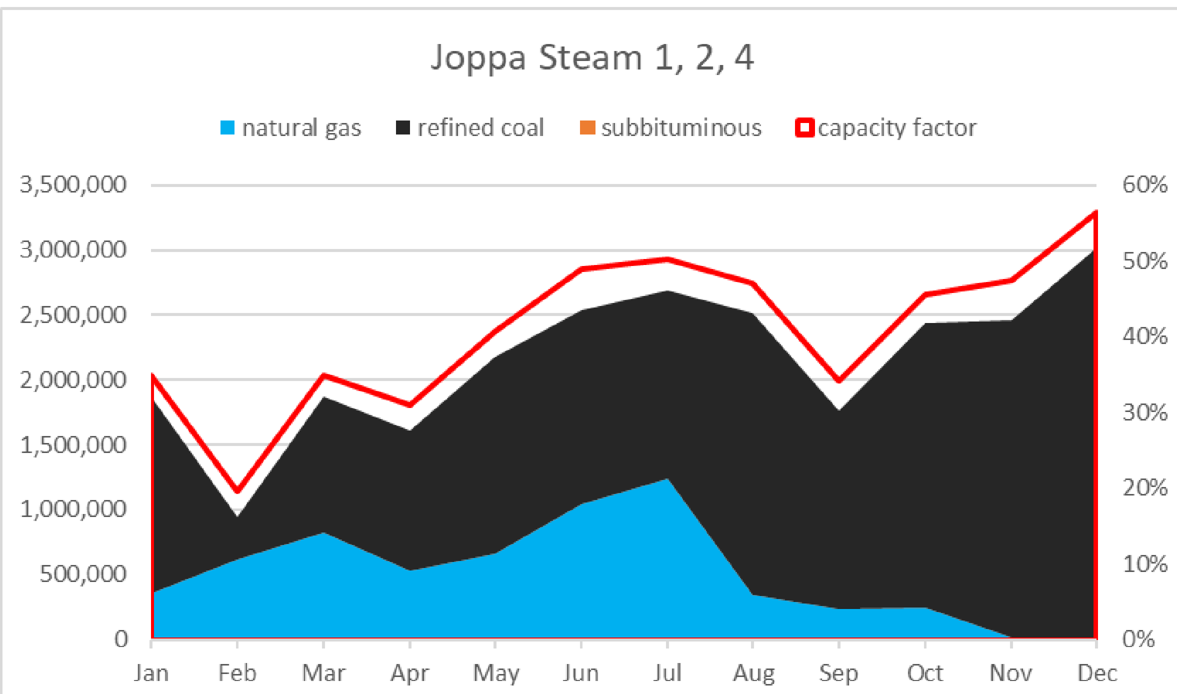
[21] https://www.ncwarn.org/2021/04/duke-spending-283m-on-retrofitting-coal-plants/

[22] Duke Energy retrofits Marshall plant to use natural gas with coal - Charlotte Business Journal (bizjournals.com) https://www.bizjournals.com/charlotte/news/2021/12/14/duke-energy-marshall-steam-station-retrofit-gas.html

Joppa Steam

Joppa Steam is an 1,100 MW, six-unit coal facility in Illinois. Each of the six units are roughly the same size. Also, unlike Cliffside and Belews Creek, which have wet FGD and SCR pollution control systems as well as PM control devices, Joppa is only equipped with ESPs for PM control. As such, Joppa Steam is a very different plant than either Cliffside or Belews Creek because it is six, small, unscrubbed units – not typical of what many regard as flagship units. It is also located in the Midwest. This doesn't impact the technical feasibility or the expected cost, however, just the nature of the units and how they fit into the overall coal fleet. Joppa Steam has been cofiring with natural gas in recent years. Its owner, Vistra, has announced its intention to retire the plant as a coal plant prior to 2025. Joppa Steam cofired 14% of its total heat input as natural gas in 2020 and 24% of total heat input as natural gas for just units 1, 2, and 4. Figure 9 shows the 2020 heat input by month for Joppa Steam. Cost information for any modifications to cofire natural gas was not found.

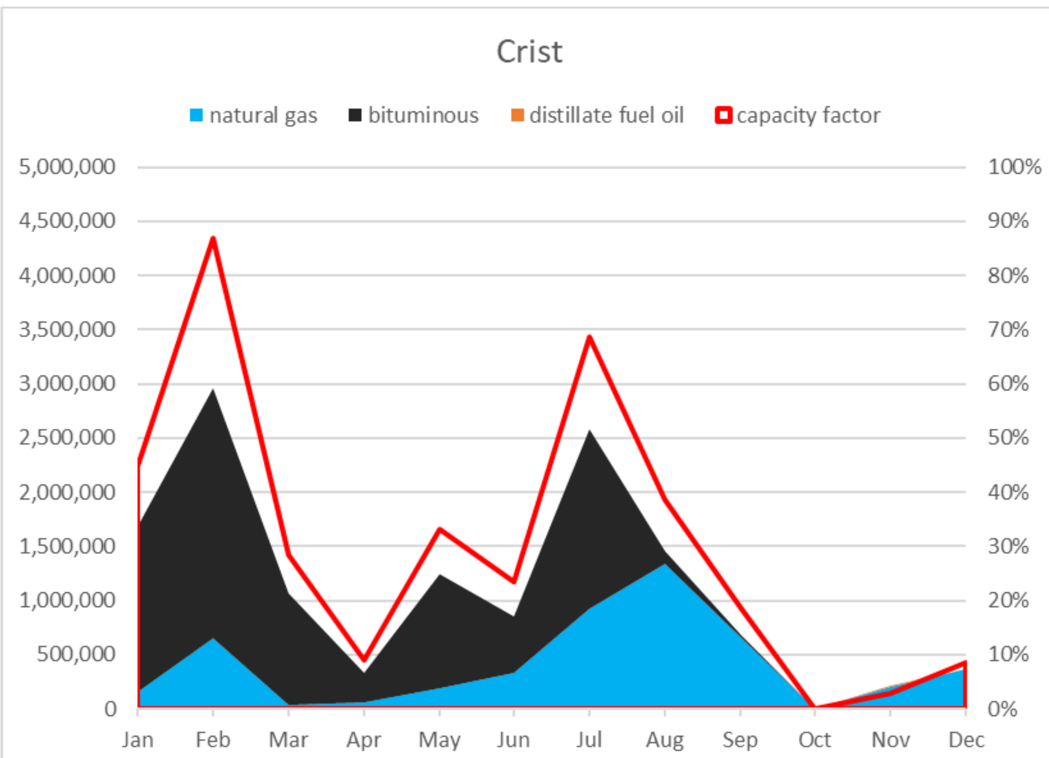
Figure 9. Fuel usage per month (MMBtu) by fuel in 2020 for Joppa 1, 2, and 4



Plant Crist/ Gulf Clean Energy Center

Plant Crist, now called the Gulf Clean Energy Center, was fully converted to a natural gas facility during 2020 but previously cofired. Over the course of 2020, units 6 & 7 (the remaining active units, at 370 MW and 578 MW, respectively) were converted from cofiring units to full gas conversions (see Figure 10). The decision to do a full conversion to natural gas was spurred by the fact that some of the coal equipment was damaged by Hurricane Sally and it made more sense to retire the coal operations completely.[23] A 39 mile pipeline was built to supply the natural gas. The early retirement of coal operations at Plant Crist enabled Gulf Power to reduce its environmental recovery costs and therefore reduce residential customer bills, estimated at a net bill reduction of $0.73.[24]

Figure 10. Fuel usage per month (MMBtu) by fuel in 2020 for Crist 6 & 7



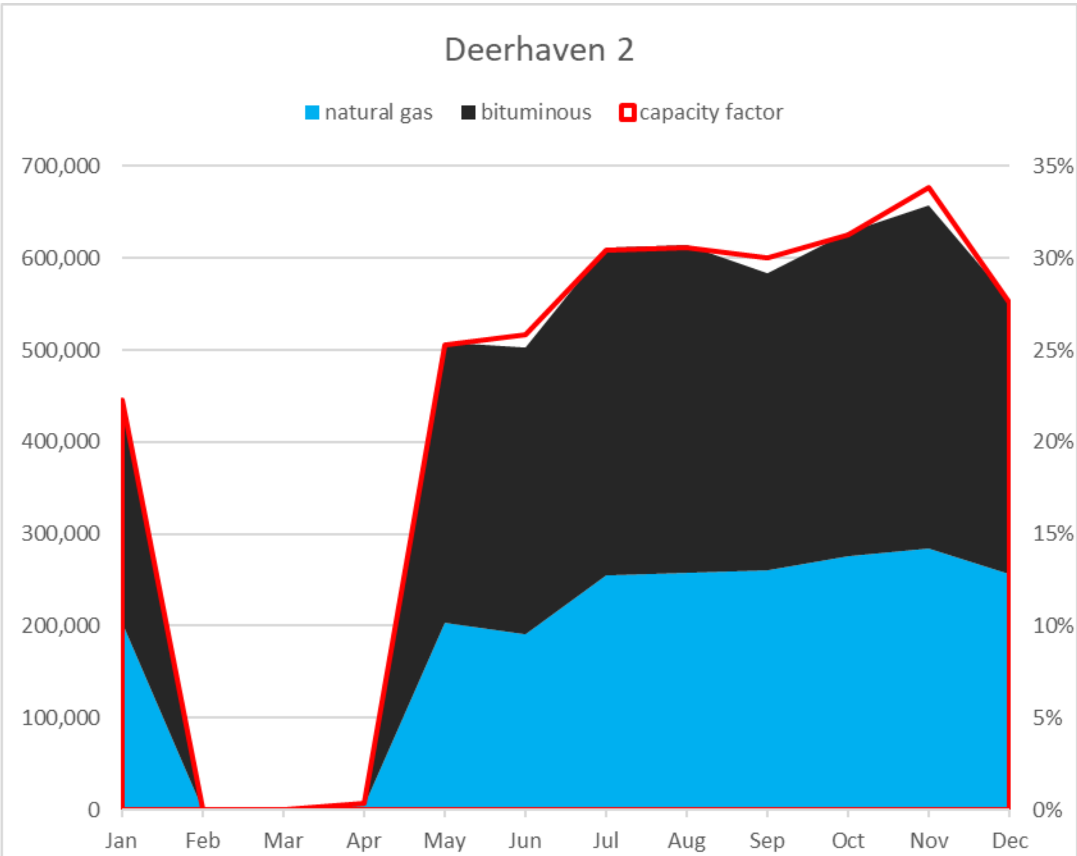
[23] Little, J., Gulf Power's Plant Crist converts to natural gas, renamed Gulf Clean Energy Center, *Pensacola News Journal*, January 22, 2021, also: https://www.gulfpowernews.com/plant-crist-modernization/

[24] It is assumed that this is the impact on a residential monthly bill, although the citation did not indicate if it was monthly or not.

Deerhaven

Gainesville Municipal Utilities' Deerhaven power plant is located in Gainesville, FL. Its cofiring retrofit was forecast to cost $12.5 million for the 228 MW facility, or about $55/kW, allowing it to operate up to 100% gas.[25] Although the facility was designed to burn up to 100% natural gas, in 2020, 43% of its fuel input was from natural gas. The configuration will enable it to utilize fuel opportunistically, using the least expensive fuel at the time. Monthly fuel use for 2020 is shown in Figure 11.

Figure 11. Fuel usage per month (MMBtu) by fuel in 2020 for Deerhaven 2

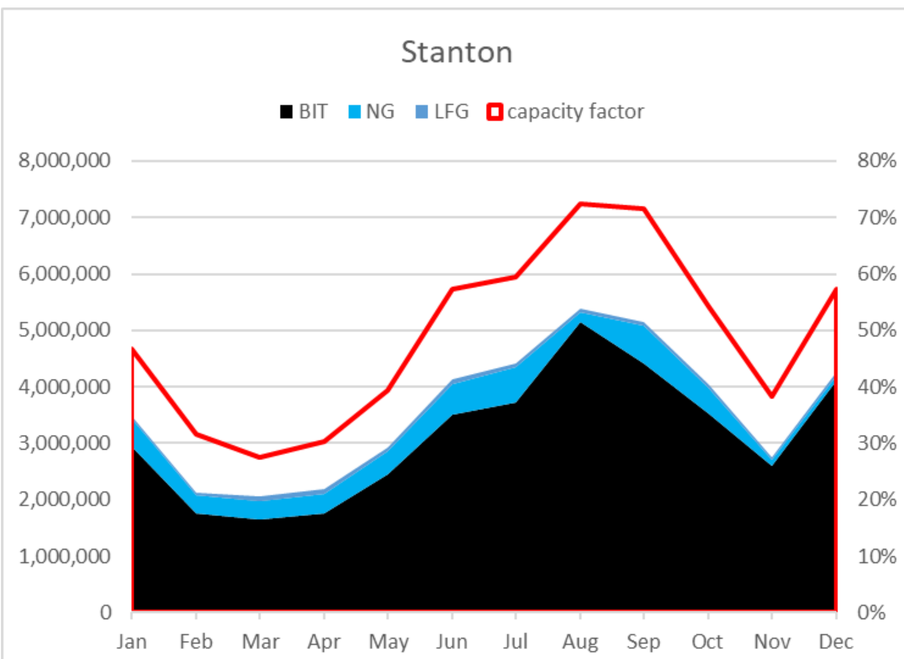


[25] https://www.wuft.org/news/2020/06/15/grus-switch-from-coal-to-cleaner-natural-gas-at-deerhaven-unit-2-would-cost-upwards-of-12m/ - It is unclear if the reported cost includes pipeline modifications. To be conservative, it will be assumed for the moment that it does not.

Stanton

Orlando Utility Commission's (OUC) Stanton Energy Center is planning to fully replace coal at units 1 & 2 (464 MW each) to natural gas by 2027.[26] However, since the mid-2010s it has been cofiring landfill gas and natural gas with coal. In 2020, 11% of the total thermal input was from natural gas. At this level of cofiring, OUC could use igniters to achieve adequate natural gas input; however, OUC found it was necessary to use igniters designed for cofiring operation at full load.[27] Igniters designed solely for startup (such as class 2 or 3 igniters) were not adequate, not being robust enough for the higher furnace temperatures at full load and not having sufficient fuel input capacity. Class 1 igniters were installed, which can operate up to full load temperature conditions and can provide over 10% of furnace heat input. Although cost information for this boiler modification was not available, based upon the scope the cost of this retrofit was likely well below the cost of the retrofits for higher levels of cofiring because it was limited to replacement of gas igniters. Higher levels of cofiring would typically entail additional gas fuel guns or larger guns. Monthly fuel use data for Stanton in 2020 and estimated capacity factor is shown in Figure 12.

Figure 12. Fuel usage per month (MMBtu) by fuel in 2020 for Stanton units 1 & 2.



[26] https://www.clickorlando.com/news/local/2021/01/14/heres-why-residents-welcome-changes-at-orlandos-stanton-energy-plant/

[27] https://www.power-eng.com/renewables/ouc-ignites-shift-to-fuel-diversity-at-stanton-energy-center/#gref

Big Bend

Big Bend is a 1,700 MW four-unit coal plant in Florida. In 2014, Tampa Electric initiated a project to replace the oil igniters at all four Big Bend units with high heat input natural gas igniters. This allowed firing igniter gas to achieve full load when one coal mill is out of service and allowed each of the units to potentially operate at 33% of full load with all of the coal mills out of service.

Tampa Electric Company described the project in a Power Engineering article:

> *"Units 1, 2, and 3 originally paired twenty-four 15-MMBtu/h oil igniters with twenty-four coal burners. These boilers are Wet Bottom Riley Stoker TURBO Furnaces characterized by upper and lower furnace zones separated by a venture-shaped construction. Burners are mounted in the lower furnace on opposite downward facing arches. The igniters provided 360 MMBtu/h of heat input per unit. In converting to natural gas, Tampa Electric specified a total boiler heat input of 1680 MMBtu/h for the new igniters, nearly five times greater than the heat input with the oil igniters."* [28]

> *"For Units 1-3, the gas igniters were provided with a total guaranteed heat input of 1680 MMBtu/h (70 MMBtu/h x 24 igniters),and for Unit 4 the guaranteed heat input is 1920 MMBtu/h (70 MMBtu/h x 16 igniters + 200 MMBtu/h x 4 warm-up guns). The total combined capacity for the system with all four units firing is 6960 MMBtu/hr. This allows the operators for each Unit to potentially achieve 33% of full load when firing igniter gas only. This provided added fuel flexibility and allowed running at full load when one pulverized coal mill on any Unit is out-of-service."*

These gas igniters and guns provided roughly three times the heat input of the previously installed oil igniters. This system was projected to save $76 million in fuel costs (substituting natural gas for distillate fuel oil).

According to Tampa Electric's 10K for the year 2015, this project cost $10 million to retrofit the plant's boiler ignition systems.[29]

Figures 13 and 14 show the annual fuel usage and estimated capacity factor for the entire plant and for units 1 & 2, respectively. Units 1 & 2 burned 100% natural gas in 2020.

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[28] https://www.power-eng.com/coal/conversion-to-natural-gas-igniters-reduces-fuel-cost/

[29] Tampa Electric 2015 10K, page 51

Figure 13. Fuel usage per month (MMBtu) by fuel in 2020 for Big Bend.

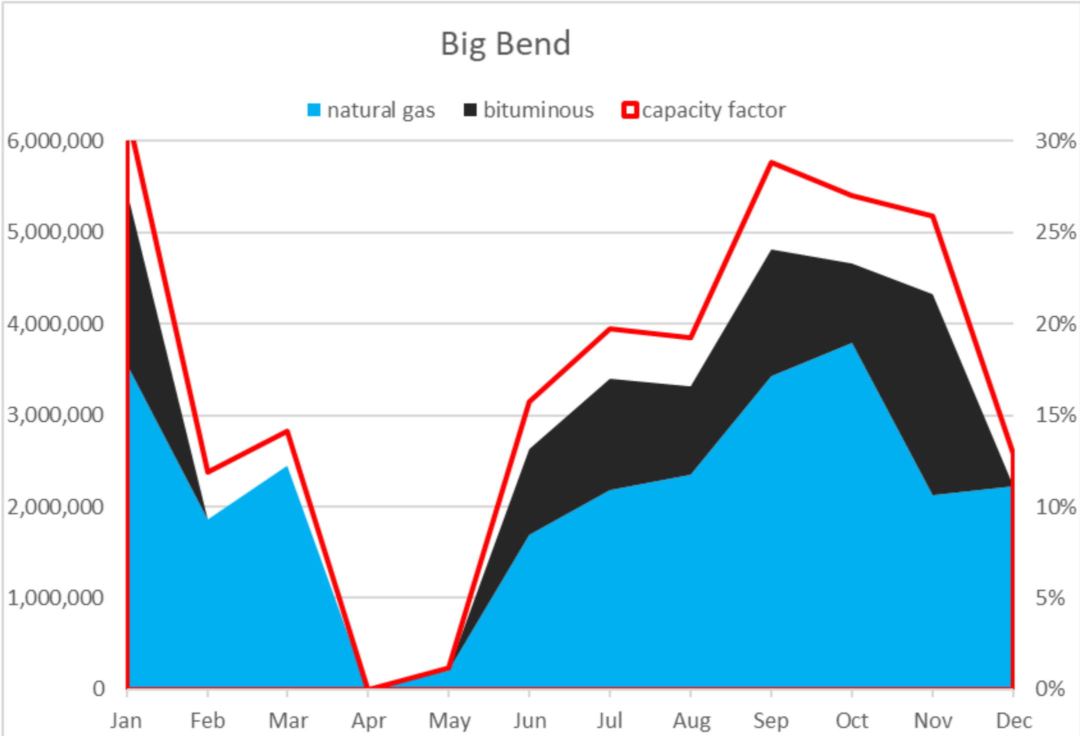
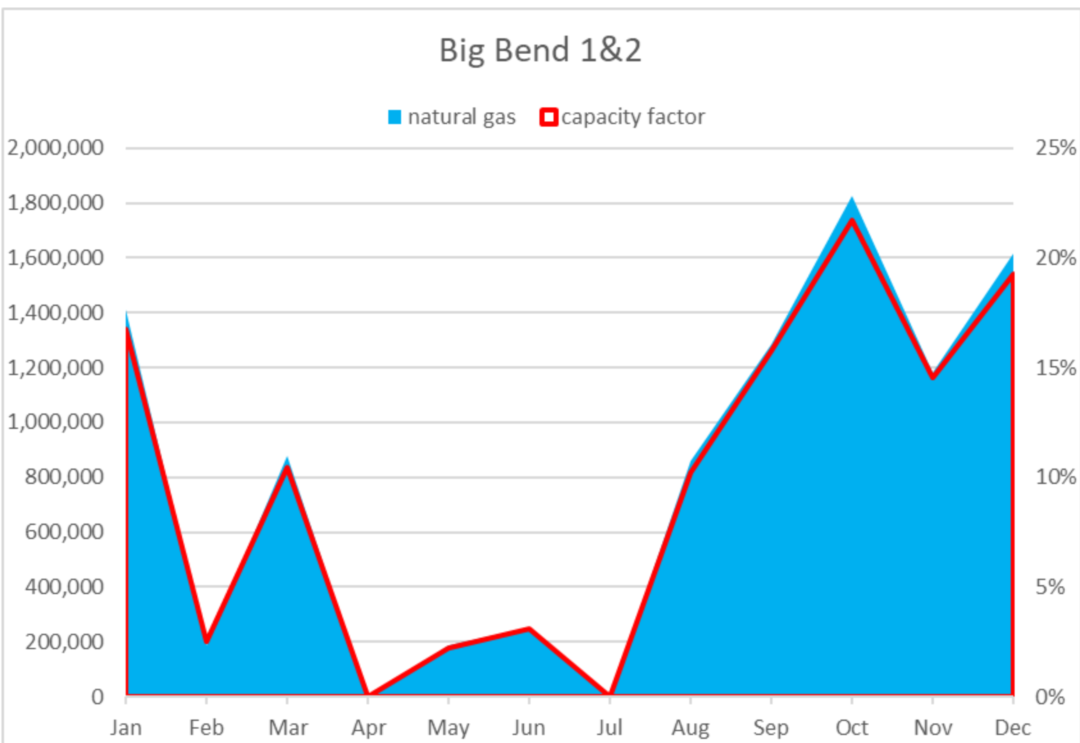


Figure 14. Fuel usage per month (MMBtu) by fuel in 2020 for Big Bend units 1 & 2



V. Costs associated with natural gas cofiring

Costs associated with natural gas cofiring include capital costs, operation and maintenance costs, and fuel costs.

Capital costs

EPA has developed an algorithm to estimate the costs of converting coal plants to natural gas plants for use in IPM modeling. To date, EPA has not developed retrofit costs for cofiring. The conversion cost assumptions for IPM v5 are shown in Table 2. For a 500 MW unit, this would translate to $148/kW and $193/kW (2016$) for PC and cyclone units, respectively.

Table 2. Incremental Capital Cost $/kW for Coal to Gas conversion used in EPA IPM Modeling.[30]

Factor	Cost (2016$/kW)
Incremental Capital Cost	PC Units: 288*(75/MW)^0.35 Cyclone: 374*(75/MW)^0.35

This algorithm was developed from engineering estimates and assumed the following scope:

- New gas burners
- Modifications to ducting, windbox and heating surfaces
- Possible modification of environmental equipment
- Engineering studies performed to assess operating characteristics like furnace heat absorption and exit gas temperature; material changes affecting piping and components like superheaters, reheaters, economizers, and recirculating fans; and operational changes to sootblowers, spray flows, air heaters, and emission controls.

As discussed in the previous section, the boiler modifications for natural gas cofiring are substantially less involved because burners are not replaced (rather, gas guns are added to existing burners and/or igniters are changed), ductwork modifications will generally be less involved, at least in part because the primary air is still available. Heat transfer is not as impacted with gas cofiring because there is still a coal flame that adds luminosity to the flame versus a purely natural gas flame. Therefore, the costs for a cofiring project would be expected to be far less than a full gas conversion, and the algorithms used by EPA for a gas conversion likely overestimate the costs of a gas cofiring project. Furthermore, previous analysis suggest that actual coal to natural gas

[30] US EPA, IPM v5 Documentation, Chapter 5, Section 5.7

conversion costs could be significantly lower than EPA estimates.[31] There are publicly reported costs for full natural gas conversion for Joliet and for Clinch River, and these were lower in cost than predicted with EPA's algorithm.[32] A report by Kokkinos estimated cost for full natural gas conversion between ~$60-$100/KW with costs escalated to 2020 dollars using the Chemical Engineering Plant Cost Index[33], significantly lower than the coal to gas conversion cost estimates EPA has used to date.

Fortunately, there is publicly available data on cofiring projects. This study estimates capital costs associated with boiler modifications using data from actual cofiring facilities for which data was available, shown in Table 3. Costs were found for six plants with a total of 14 units that are capable of cofiring at least 40% of full load natural gas (an additional plant with four units, Big Bend, can fire up to 33% load on natural gas). Because costs associated with the gas pipeline were included in one of the reported cofiring capital costs, pipeline costs are estimated and deducted from the total cost using an assumption of $1 million per mile, with mileage based upon reported mileage or from estimates made from EIA's Energy Infrastructure Map.

The reported capital costs for cofiring retrofits range from $47-$67/kW for cofiring between 40%-100% heat input as natural gas with most projects around $50/kW. These costs are only approximate, and cofiring modification costs will vary to some degree on a site-specific basis. The resulting costs as a function of different gas firing levels are shown in Figure 15. As a comparison, a 2013 analysis by Black and Veatch estimated a range of cofiring capital costs of between $10-$100/kW and reported costs for the Joliet and Clinch River coal to gas conversions are shown.[34] Also shown for comparison are upper and lower bound costs reported by Kokkinos (UBS) for

[31] Andover Technology Partners, *Natural Gas Conversion and Cofiring for Coal-Fired Utility Boilers*, for Environmental Defense Fund, November 30, 2014

[32] Cichanowicz, J.E., Overview of Issues Presented By Natural Gas Co-firing and Fuel Switching at Coal-Fired Electric Generating Units", for the Utility Air Regulatory Group, October 2018, pg. 15. p

[33] UBS Investment Research Coal to Gas Plant Conversion Conference Call Transcript, Interview with Angelos Kokkinos of Babcock Power, May 29, 2013, Kokkinos reported roughly $50-$80/kW. An additional 20% is provided for owner's costs, and an additional 5% for escalation from 2013 to 2020. Owner's costs are project management and other overhead costs associated with contracting.

[34] Nowling, U., Utility Options for Leveraging Natural Gas, Power Magazine, October 1, 2013. https://www.powermag.com/utility-options-for-leveraging-natural-gas/

Cichanowicz, J.E., Overview of Issues Presented By Natural Gas Co-firing and Fuel Switching at Coal-Fired Electric Generating Units", for the Utility Air Regulatory Group, October 2018, pg. 15

natural gas conversion, with costs escalated to 2020 dollars using the Chemical Engineering Plant Cost Index and reported costs for full natural gas conversion for Joliet and for Clinch River.[35]

Table 3. Reported capital costs for natural gas cofiring projects, excluding gas pipeline.[36]

	Big Bend[1]	Marshall	Belews Creek 1 & 2	Cliffside 5 & 6	Brunner Island	Deerhaven	Montour[4]
Total equipment (Million $)	10	104	117	65	110	12.5	70
Capacity (MW)	1700	2119	2240	1395	1600	228	1504
No. of units	4	4	2	2	3	1	2
Pipeline distance (mi) if included in total equipment					3		
Est pipeline cost (Million $)					3[2]		
Est boiler modification cost (Million $)	10	104	117	65	107	12.5	70
Boiler mod cost ($/kW)	6[1]	49	52	47	67	55	47
Max percent cofiring possible	33%	47%[3]	50%	75%[3]	100%[5]	100%[5]	100%[5]

[1] Modifications at Big Bend were limited to replacement and upgrade of ignition systems, while the other plants in this table involved further modifications. For these reasons, Big Bend is excluded from cost estimates but shown here for reference.
[2] Assumes a pipeline cost of $1 million per mile.
[3] These are capacity weighted percentages based upon 40% for Cliffside 5 and 100% for Cliffside 6, 40% for Marshall 1 & 2 and 50% for Marshall 3 & 4.
[4] Talen Energy announced plans in 2016 to install boiler modifications at Montour to enable cofiring capability, and estimated the plant modifications would cost approximately $70 million. Talen Energy did not ultimately go through with the modifications and Montour does not currently cofire, however the estimated costs are included because they are in the same range as the other data.
[5] Cofiring up to 100% of heat input is different than a full conversion to natural gas. Full conversion is more costly and would require more equipment modifications.

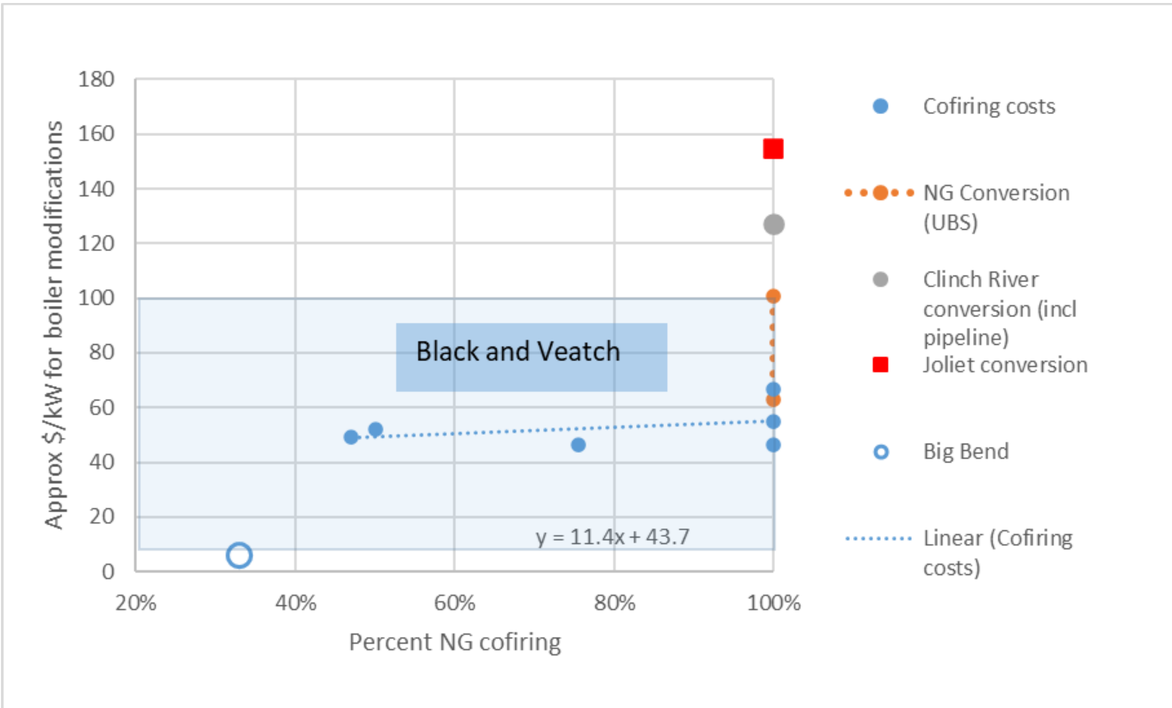
As shown in Table 3, the Big Bend costs are much lower than other units that have higher levels of gas cofiring. This is likely because this retrofit was limited to changing existing oil igniters to more capable gas igniters versus addition of gas capability to coal fired burners, which is somewhat more involved.

35 For Joliet and Clinch River, pipeline costs were estimated at $1 million per mile estimated from EIA's Energy Infrastructure map

36 Cost data sources:
Big Bend: https://www.sec.gov/Archives/edgar/data/96271/000156459016013516/te-10k_20151231.htm
Marshall: https://www.bizjournals.com/charlotte/news/2021/12/14/duke-energy-marshall-steam-station-retrofit-gas.html
Belew's Creek: https://www.ncwarn.org/2021/04/duke-spending-283m-on-retrofitting-coal-plants/
Cliffside: https://www.bizjournals.com/charlotte/news/2018/11/19/duke-energy-wrapping-up-65m-gas-co-firing-project.html
Brunner Island: https://www.sec.gov/Archives/edgar/data/1622536/000162253616000111/tln-20151231x10k.htm
Deerhaven: https://www.wuft.org/news/2020/06/15/grus-switch-from-coal-to-cleaner-natural-gas-at-deerhaven-unit-2-would-cost-upwards-of-12m/
Montour: https://talenenergy.investorroom.com/2016-06-07-Talen-Energy-to-Co-fire-Montour-Plant
https://www.dailyitem.com/news/local_news/talen-delays-montour-plant-gas-conversion/article_3153990b-e573-5238-b176-32b95c6a94f6.html

An attempt was made to see if the capacity scaling factors in the EPA algorithm could be applied to this data, and it was found that the capital cost did not scale with capacity in this manner. A more thorough examination with more data might uncover some capacity scaling effects, if any.

Figure 15. Estimated capital costs of boiler modifications for different cofiring levels and natural gas conversion.[37]



Fuel costs

As will be shown, fuel costs have the most significant impact. Assuming no difference in efficiency or other costs and typical 213 lb/MMBtu CO_2 emission rate for coal and 117 lb/MMBtu CO_2 emission rate for natural gas, for every $1.00/MMBtu in difference in fuel cost between coal and natural gas, the cost is $20.83 per ton of CO_2 reduced. However, to arrive at better estimates, it is necessary to examine the impact of other costs associated with operation of the power plant.

CO_2 abatement costs

The CO_2 abatement costs associated with cofiring natural gas were also estimated. Figure 16 shows estimated cost per ton of CO_2 reduced for natural gas cofiring at different levels of cofiring

[37] Costs for Clinch River did not distinguish gas pipeline costs versus boiler costs. However, EIA Energy Maps show that the interstate pipeline is only a few miles from the power plant. So, any interconnect costs would be commensurate.

for a 550 MWg[38] coal unit operating at a capacity factor of 35%, with natural gas cost at \$3.50/MMBtu and coal cost at \$2.00/MMBtu. Figure 17 shows the CO_2 abatement cost at a natural gas cost of \$5.00/MMBtu.[39] Calculations were performed for both PRB and bituminous coal. Assumptions were made for impacts on parasitic loads and on boiler efficiency.

Figure 16. Estimated cost of reducing CO2 emissions with natural gas cofiring for PRB and bituminous coals and percent CO2 reduction - \$/ton of CO2 reduced versus percent natural gas heat input. Cost of natural gas is assumed to be \$3.50/MMBtu versus \$2.00/MMBtu for coal.

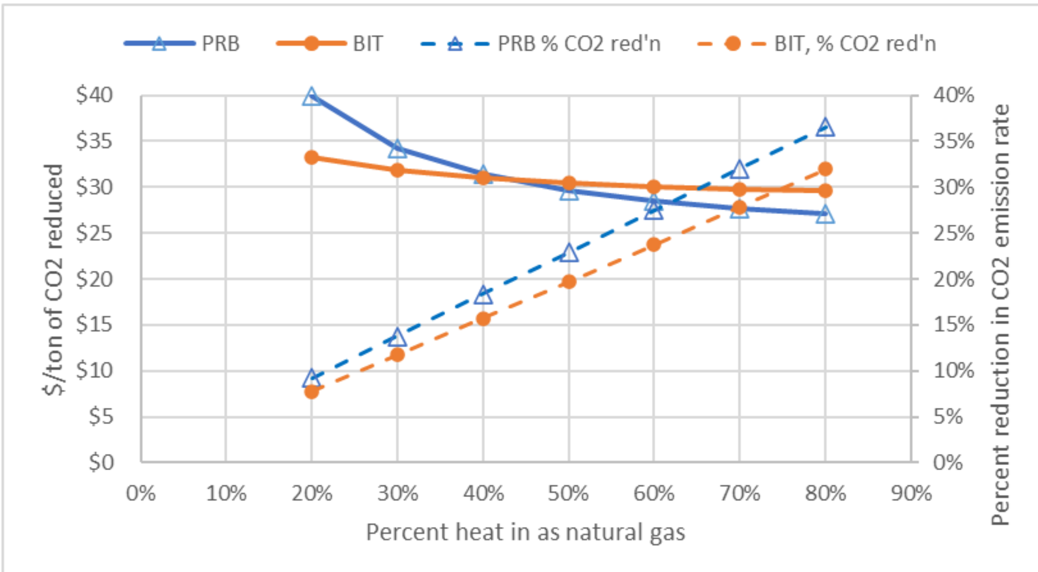
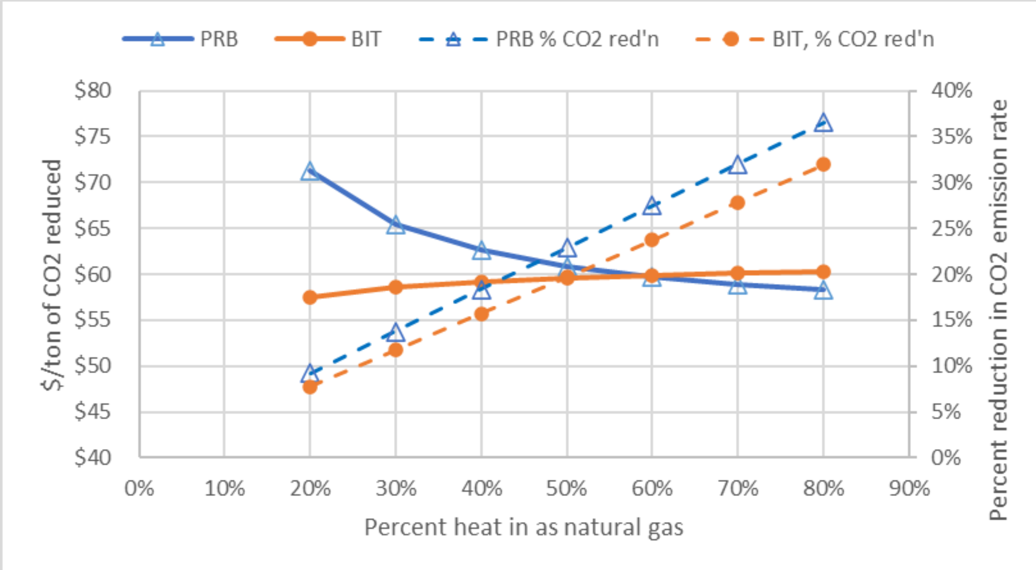


Figure 17. Estimated cost of reducing CO2 emissions with natural gas cofiring for PRB and bituminous coals and percent CO2 reduction - \$/ton of CO2 reduced versus percent natural gas heat input. Cost of natural gas is assumed to be \$5.00/MMBtu versus \$2.00/MMBtu for coal.

[38] MWg means MW gross, which is before parasitic loads are deducted. Net capacity to the grid will be somewhat less.

[39] Examination of current EIA data shows that these fuel costs are in the range for many electric utility applications. Specific applications may have different fuel costs.



Parasitic load, estimated from DOE baseline studies[40] in proportion to capacity, were individually scaled relative to impact from reduction in coal usage. For example, fuel preparation costs were reduced in proportion to the reduction in coal use. Primary air plus forced draft load are reduced in proportion to the reduction in excess air. Parasitic loads for items that are not impacted by fuel choice, such as circulating water pumps, remained the same. Similarly, costs for chemical use (ie, scrubber chemicals) associated with coal use were also reduced in proportion to coal reduction. Fixed O&M was reduced by up to 10% in a linear fashion,[41] because some reduction is expected, although some costs will remain because coal equipment remains in service but is used to a lesser degree. This is considered a conservative estimate. Impact on boiler efficiency was assumed to behave in a linear fashion between 100% coal use and 100% gas use while using the data in Table 1 for both PRB coal, bituminous fuel and natural gas. As shown in Table 1, the impact is greater for bituminous fuel than for PRB.

Capital costs are assumed to be recovered over 15 years at an interest rate of 7%, with a capital recovery factor of 11% resulting. Although the percent natural gas cofiring impacts the capital cost used in these calculations, the impact is relatively low in light of the relatively shallow slope of the line in Figure 15.

[40] National Energy Technology Laboratory, Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity, September 24, 2019, Exhibits 4-19 and 4-20

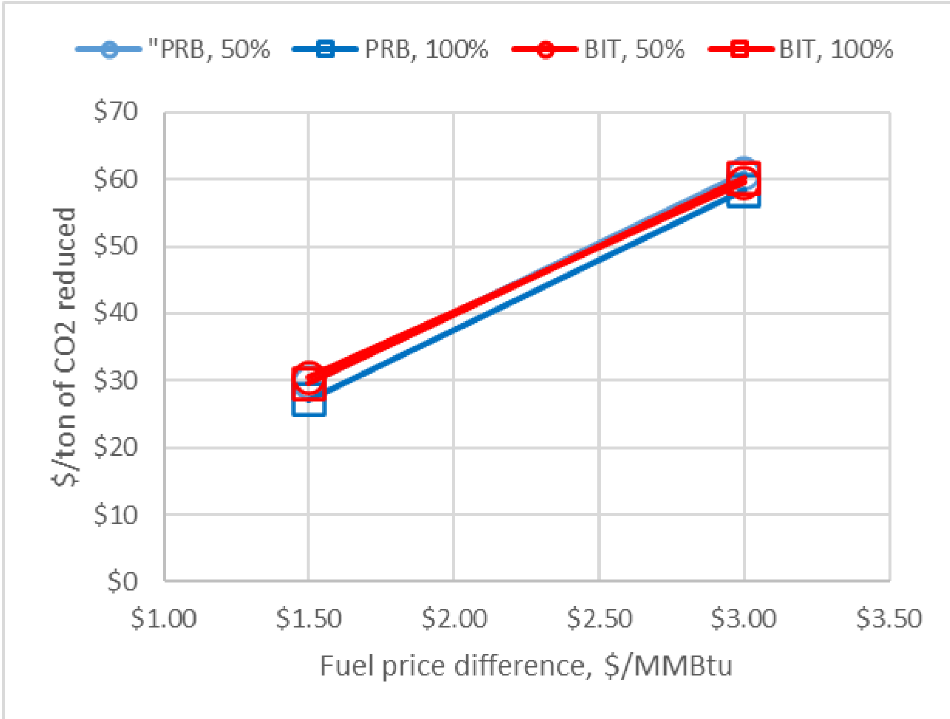
[41] This compares to 33% assumed by EPA for a full gas conversion and 50% estimated by Kokkinos for a full gas conversion. A lower percent reduction in fixed O&M is used in this analysis because coal equipment remains in place when cofiring, even though it is used to a much lower degree.

Cost estimates would differ for unscrubbed units to the extent that cofiring at scrubbed units has an impact on chemicals and some of the scrubber loads. However, the large majority of coal capacity is equipped with scrubbers.

Figures 16 and 17 show that, in these specific cases, the cost per ton of CO_2 reduced decreases for PRB fuel as the share of natural gas increases, and increases for bituminous fuel. Cofiring has competing effects that impact cost: impact on boiler efficiency, increased capital costs and increased fuel costs as natural gas cofiring is increased on the one hand, and on the other hand, reduced reagent costs, lower operating and maintenance costs, and reduced parasitic loads as natural gas cofiring is increased. The adverse impact of natural gas on boiler efficiency is generally greater for bituminous than for PRB units, and that will also differ based upon the ash characteristics for bituminous units. For bituminous units with furnace slag that cleans more easily, the adverse impact of natural gas on boiler efficiency due to moisture in the flue gas will be offset by improved heat transfer. These estimates assume that the adverse impact of increased cofiring on boiler efficiency on a bituminous coal unit is greater than that for a PRB unit and the impact on boiler efficiency behaves linearly between 0% and 100% between the levels shown in Table 1. As shown, costs are in the range of \$25/ton of CO_2 to \$30/ton of CO_2 for fuel costs of \$2.00/MMBtu for coal and \$3.50/MMBtu for natural gas. Abatement costs are around \$60/ton of CO_2 for fuel costs of \$2.00/MMBtu for coal and \$5.00/MMBtu for natural gas. Tables in the appendices show some of the information from the calculations. Notably, the cost calculations in these figures do not include the effects of natural gas supply costs, which will increase the cost somewhat.

The data of Figures 16 and 17 are shown in a different way in Figure 18, which plots cost of CO_2 reduced versus the difference in cost for natural gas and coal for 50% or 100% natural gas cofiring situations. As shown, the cost is really driven more by the difference in the cost of fuel than coal type or cofiring level. However, the effect of fuel cost is not as great as it would be if other effects, such as reduction in parasitic loads or reduction in O&M were not considered. These can offset the effect of fuel cost to a significant degree.

Figure 18. Effect of fuel price differential on cost per ton of CO2 reduced



SO_2, PM, Hg, and NOx emissions will also be reduced with increased natural gas cofiring. SO_2, PM and Hg will be reduced approximately at the same rate as the level of cofiring (ie, 50% cofiring will reduce SO_2 emissions by roughly 50%) and NOx emissions will generally drop, but by a level that will be determined by the specifics of the situation.

Conclusions

This report demonstrates that natural gas cofiring projects are technically feasible and are, in fact, underway. There are dozens of facilities that currently cofire that cover a wide range of boiler types, capacities, configurations, and locations. A few of them have been highlighted in this report.

The requirements for cofiring, from the perspective of the boiler, are easily manageable, and are significantly less than for a full gas conversion. Technical aspects of these modifications are well understood because cofiring natural gas has been performed at different facilities and has been examined for several decades. Moreover, the capital costs of a cofiring retrofit are significantly less than those of a full natural gas conversion.

Depending upon the circumstances, the capital cost of a cofiring retrofit to fire between 40% and 100% heat input as gas is in the range of about $50/kW, with some variability above and below this range. For high levels of cofiring (e.g. 100% of heat input) – the capital cost of a cofiring retrofit will be higher than lower co-firing levels but still less than costs of full conversion. These capital cost estimates are based on data from 14 units at six plants that are capable of cofiring at least 40% of their fuel input as natural gas. This represents a significant portion (35%) of the roughly 40 units that cofired at rates of 5% or more in 2020. Therefore, while the precise cost of any project will depend upon the project specifics, the capital cost estimates developed here are expected to be representative.

Estimates of the cost of CO_2 reduction, as expected, show it to be highly dependent upon the cost differential between natural gas and coal. A cost differential of $1.50/MMBtu results in cost of CO2 reduced in the range of $20/ton to $30/ton of CO2 reduced. A cost differential of $3.00/MMBtu results in cost of CO_2 reduced in the range of $50/ton to $60/ton of CO2 reduced. The type of coal and specifics of the unit will also impact the cost somewhat because this will impact the boiler efficiency and have other effects. However, the cost differential between the fuels is, unsurprisingly, the most significant factor.

Appendices

Table 1: Cost Estimates for PRB Units – Annual Costs									
Percent natural gas cofiring	**0%**	**10%**	**20%**	**30%**	**40%**	**50%**	**60%**	**70%**	**80%**
Capital cost, $/kW	0	45	46	47	48	49	51	52	53
Base case gross output, MW	550	550	550	550	550	550	550	550	550
Base Heat Rate, net	10000	10000	10000	10000	10000	10000	10000	10000	10000
Boiler Efficiency Impact	0.00%	0.06%	0.11%	0.17%	0.23%	0.28%	0.34%	0.40%	0.45%
Red'n in parasitic Loads, % of gross output	0.00%	0.15%	0.30%	0.45%	0.60%	0.75%	0.90%	1.05%	1.19%
Parasitic Load, % of gross output	5.39%	5.24%	5.09%	4.94%	4.79%	4.64%	4.49%	4.34%	4.19%
Base Net Output, MW	520	520	520	520	520	520	520	520	520
Base Heat Input, MMBtu/hr	5,204	5,204	5,204	5,204	5,204	5,204	5,204	5,204	5,204
Output after adj for parasitic load and boiler efficiency	520	521	521	522	522	523	524	524	525
CO2 rate of coal, lb/MMBtu	213	213	213	213	213	213	213	213	213
CO2 rate of natural gas, lb/MMBtu	117	117	117	117	117	117	117	117	117
Operation and Maint Cost, $/kWhnet									
Chemicals	0.00108	0.000972	0.000864	0.000756	0.000648	0.00054	0.000432	0.000324	0.000216
Waste disp	0.00091	0.000819	0.000728	0.000637	0.000546	0.000455	0.000364	0.000273	0.000182
Operation and Maint Cost, $/MMBtu									
Chemicals	0.108	0.0972	0.0864	0.0756	0.0648	0.054	0.0432	0.0324	0.0216
Waste disp	0.091	0.0819	0.0728	0.0637	0.0546	0.0455	0.0364	0.0273	0.0182
O&M Labor, $/kWnet	69.47	68.7753	68.0806	67.3859	66.6912	65.9965	65.3018	64.6071	63.9124
Fuel Cost, Coal, $/MMBtu	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00
Fuel Cost, natural gas, $/MMBtu	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00

Table 1: Cost Estimates for PRB Units – Annual Costs									
Percent natural gas cofiring	**0%**	**10%**	**20%**	**30%**	**40%**	**50%**	**60%**	**70%**	**80%**
Capital cost ($ millions)	0	24.662	25.289	25.916	26.543	27.17	27.797	28.424	29.051
Capital payment (millions)	$0.00	$2.71	$2.78	$2.85	$2.91	$2.98	$3.05	$3.12	$3.19
		40%	25%	19%	15%	13%	11%	10%	9%
Fixed O&M, millions	$36	$36	$35	$35	$35	$34	$34	$34	$33
Capacity Factor	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35
Annual net generation, MWh	1,595,480	1,597,089	1,598,695	1,600,298	1,601,898	1,603,495	1,605,089	1,606,680	1,608,269
Annual Heat Input, MMBTU	15,954,803	15,954,803	15,954,803	15,954,803	15,954,803	15,954,803	15,954,803	15,954,803	15,954,803
Coal Cost, millions	32	29	26	22	19	16	13	10	6
natural gas Cost, millions	0	8	16	24	32	40	48	56	64
Power value, $/MW	25	25	25	25	25	25	25	25	25
Change in net gen from base, (MWh)	0	1,609	3,214	4,817	6,417	8,014	9,609	11,200	12,789
Chemicals/waste	$3	$3	$3	$2	$2	$2	$1	$1	$1
Cost, millions	$71.24	$78.01	$82.15	$86.28	$90.42	$94.56	$98.69	$102.83	$106.96
CO2 Emissions, tons	1,699,187	1,622,604	1,546,020	1,469,437	1,392,854	1,316,271	1,239,688	1,163,105	1,086,522
CO2 Rate, lb/Mwnet	2,130	2,032	1,934	1,836	1,739	1,642	1,545	1,448	1,351
PRB % CO2 red'n (lb/MWn basis)		4.6%	9.2%	13.8%	18.4%	22.9%	27.5%	32.0%	36.6%
Cost of CO2 reduction ($/ton)		**$88.47**	**$71.24**	**$65.49**	**$62.62**	**$60.90**	**$59.75**	**$58.93**	**$58.32**

Table 2: Cost Estimates for Bituminous Units– Annual Costs									
Percent natural gas cofiring	**0%**	**10%**	**20%**	**30%**	**40%**	**50%**	**60%**	**70%**	**80%**
Capital cost, $/kW	0	45	46	47	48	49	51	52	53
Base case gross output, MW	550	550	550	550	550	550	550	550	550
Base Heat Rate, net	10000	10000	10000	10000	10000	10000	10000	10000	10000
Boiler Efficiency Impact	0.00%	0.63%	1.26%	1.89%	2.52%	3.15%	3.78%	4.41%	5.04%
Red'n in parasitic Loads, % of gross output	0.00%	0.15%	0.30%	0.45%	0.60%	0.75%	0.90%	1.05%	1.19%
Parasitic Load, % of gross output	5.39%	5.24%	5.09%	4.94%	4.79%	4.64%	4.49%	4.34%	4.19%
Base Net Output, MW	520	520	520	520	520	520	520	520	520
Base Heat Input, MMBtu/hr	5,204	5,204	5,204	5,204	5,204	5,204	5,204	5,204	5,204
Output after adj for parasitic load and boiler efficiency	520	518	515	513	510	508	505	503	500
CO2 rate of coal, lb/MMBtu	206	206	206	206	206	206	206	206	206
CO2 rate of natural gas, lb/MMBtu	117	117	117	117	117	117	117	117	117
Operation and Maint Cost, $/kWhnet									
Chemicals	0.00108	0.000972	0.000864	0.000756	0.000648	0.00054	0.000432	0.000324	0.000216
Waste disp	0.00091	0.000819	0.000728	0.000637	0.000546	0.000455	0.000364	0.000273	0.000182
Operation and Maint Cost, $/MMBtu									
Chemicals	0.108	0.0972	0.0864	0.0756	0.0648	0.054	0.0432	0.0324	0.0216
Waste disp	0.091	0.0819	0.0728	0.0637	0.0546	0.0455	0.0364	0.0273	0.0182
O&M Labor, $/kWnet	69.47	68.7753	68.0806	67.3859	66.6912	65.9965	65.3018	64.6071	63.9124
Fuel Cost, Coal, $/MMBtu	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00
Fuel Cost, natural gas, $/MMBtu	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00

Table 2: Cost Estimates for Bituminous Units– Annual Costs									
Percent natural gas cofiring	**0%**	**10%**	**20%**	**30%**	**40%**	**50%**	**60%**	**70%**	**80%**
Capital cost ($ millions)	0	24.662	25.289	25.916	26.543	27.17	27.797	28.424	29.051
Capital payment (millions)	$0.00	$2.71	$2.78	$2.85	$2.91	$2.98	$3.05	$3.12	$3.19
Fixed O&M, millions	$36	$36	$35	$35	$35	$34	$34	$34	$33
Capacity Factor	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35
Annual net generation, MWh	1,595,480	1,587,934	1,580,357	1,572,748	1,565,107	1,557,434	1,549,729	1,541,993	1,534,225
Annual Heat Input, MMBTU	15,954,803	15,954,803	15,954,803	15,954,803	15,954,803	15,954,803	15,954,803	15,954,803	15,954,803
Coal Cost, millions	32	29	26	22	19	16	13	10	6
natural gas Cost, millions	0	8	16	24	32	40	48	56	64
Power value, $/MW	25	25	25	25	25	25	25	25	25
Change in net gen from base, (MWh)	0	-7,546	-15,123	-22,733	-30,374	-38,047	-45,751	-53,487	-61,255
Chemicals/waste	$3	$3	$3	$2	$2	$2	$1	$1	$1
Cost, millions	$0.00	$78.24	$82.60	$86.97	$91.34	$95.71	$100.08	$104.45	$108.82
CO2 Emissions, tons	1,643,345	1,572,346	1,501,347	1,430,348	1,359,349	1,288,350	1,217,352	1,146,353	1,075,354
CO2 Rate, lb/Mwnet	2,060	1,980	1,900	1,819	1,737	1,654	1,571	1,487	1,402
BIT, % CO2 red'n (lb/MWn basis)		3.9%	7.8%	11.7%	15.7%	19.7%	23.7%	27.8%	32.0%
Cost of CO2 reduction ($/ton)		**$55.22**	**$57.47**	**$58.53**	**$59.16**	**$59.56**	**$59.86**	**$60.07**	**$60.24**