OVERVIEW

Since the 1990 Clean Air Act Amendments (CAAA) were implemented in 1995, a plethora of changes to the operating environment of every electric utility has occurred. Initial (Phase I) CAAA changes were primarily related to fuel switching to lower sulfur coals in order to comply with the SO₂ caps mandated by the regulations.

Phase II CAAA changes entailed a more complicated approach of fuel switching not only to lower sulfur coals, but also co-firing or seasonal firing of natural gas. Further complicating the picture was the regulatory implications of reducing NOₓ emissions. The reduction of NOₓ required the fuel switching, low NOₓ burners, overfire air, and more recently selective catalytic reduction (SCRs). As we approach Phase III of the 1990 CAAA, the electric utility industry is forced to move to flue gas desulfurization (FGD) coupled with SCRs and, in many cases now, fabric filters with spray dry adsorption (FF) in order to meet the new mercury and hazardous air pollutant (HAP) requirements as well as the Clean Air Interstate Rule (CAIR) enacted in 2005, which implements stricter requirements for particulate matter (PM) as well as ozone.

On the industrial side, the Industrial Boiler Maximum Available Control Technology (MACT) was recently implemented. These regulations significantly impact industrial coal users with respect to mercury and other HAPs as well as implementing limits on chlorine emissions. The new MACT rules coupled with the 1990 CAAA rules that are implemented in the form of State Implementation Plans (SIPs) that regulate sulfur emissions (SO₂) and particulates in the form of opacity as well as ozone if the industrial is located in a non-attainment area.

In addition to the changes in the regulatory climate, changes in the coal, natural gas and transportation markets have contributed to major impacts to energy users. The increases in the prices of these components have caused energy users to begin to look in earnest for ways to reduce their energy costs.

Outlined in this document are the steps required to achieve lower costs and a “real world” example of the results of a study performed by the authors.

COAL STRATEGY AND BOILER OPTIMIZATION — KEY STEPS

In order to assess and optimize coal requirements for a particular boiler, many factors must be taken into account:

- Boiler type and condition
- Boiler environmental controls
- Boiler auxiliary equipment
- Environmental permits and restrictions
- Coal handling equipment and type
- Delivering transportation method
- Boiler flexibility and retrofit potential

As you can see, it is best if the equipment engineer and the coal strategist work closely together to determine what coal types have potential in the boiler. The steps in this process:
1) Determine possible coal types based on boiler parameters (quality, delivering transportation, blending, stokering, plant environmental requirements as mandated by the permits and other conditions). This is accomplished by:
   - Using its knowledge of the coal producing regions and coal reserves, the consultants will identify coal that can meet the environmental requirements for utilities and industrials such as the Clean Air Act, CAIR, Title V, Industrial Boiler MACT, and individual SIPs.
   - Evaluate blending opportunities for economics as well as for meeting environmental limits.
   - Evaluate transportation routing, method, transloading, including rail, barge and truck, in order to compare the economics of each.

2) Use the Hill and Associates Inc. (H&A) Outlook for Coal regional forecasts and quality types to determine potential coal types and price forecasts for a particular boiler:
   - Each year H&A publishes a multiclient study entitled “Outlook for Coal.” This study examines more than 90 coal types from all producing regions in the United States. The coal types are based on quality including Btu, sulfur and ash.
   - The strength of the comparative analysis lies in the consultant’s knowledge of the coal types and markets.
   - Use H&A Transportation Database and estimated freight rates to determine delivery costs to the plant. This, along with the consultant’s knowledge of logistics, will determine any additional transloading, blending or other costs related to delivering coal to the plant.
   - The result of this analysis is a matrix of the possible delivered coal types versus delivered cost.

3) Using the H&A long-term price forecast for coal, develop the economics model to evaluate potential fuel savings for the plant using the optimal coal type.

4) Provide a detailed evaluation of the boiler(s) to determine the capital conversion costs of the boiler to burn the optimum coal type.

5) Using the findings of the boiler evaluation by Burns & McDonnell, evaluate the capital conversion costs of the boiler to burn the optimum coal type and prepare a net present value analysis, rate of return analysis and payback analysis.

6) Prepare a detailed economic evaluation including net present value analysis, rate of return analysis and payback analysis.

**EXAMPLE PROJECT**

Burns & McDonnell and Hill & Associates (consultants) were retained by a company to evaluate the possibility of using a lower cost fuel for process heat at a processing plant. The company is using natural gas to operate the process heaters at its plant. Because of the recent increase in natural gas prices and the long-term outlook, the company deemed it prudent to look at lower cost options for the developing the process heat.

The consultants evaluated equipment options for the company’s plant as well as the sources of potential fuel and the estimated costs of fuel. This initial evaluation was conducted at a fairly high level to determine if the economics of the project were sufficient to continue pursuit of the process heat conversion project. The evaluation can be summarized into the following sections:
1.0 Plant Equipment Options
2.0 Alternative Fuel Options
3.0 Economic Evaluation
4.0 Environmental Considerations

1.0 PLANT EQUIPMENT OPTIONS

1.1 Circulating Fluidized Bed (CFB) Combustor

The combustion process within a fluidized bed boiler occurs in a suspended bed of solid particles in the lower section of the boiler. Combustion within the bed occurs at a slower rate and lower temperature than a conventional pulverized coal boiler while deviations in fuel type, size or Btu content have minimal effect on the furnace performance characteristics. The bed also allows for reinjection of a sorbent, such as fly ash or limestone, to reduce SO2 emissions.

MACT requirements in many areas of the country are challenging the historical characterization of fluidized bed technology as a “Clean Coal Technology.” Achieving emission levels meeting MACT requirements now requires the addition of SNCR systems for NOx control and a fly ash and/or limestone reinjection system for SO2 control.

The CFB technology is well-suited to burn fuels with a large variability in constituents. Plant sites with access to an abundant source of fuel that presents combustion challenges in a pulverized coal boiler are typically good prospects for application of fluidized bed technology.

All CFB boilers built to date are of a subcritical design. Foster Wheeler and Alstom offer supercritical CFB boilers, however none are in operation at this time. Because of the lack of industry experience and increased risk associated with supercritical CFB units, this assessment considers only subcritical CFB units.

The consultants estimate that a the capital cost for a CFB boiler to meet the customer’s requirements would be in the $40 million to $50 million range. The annual fixed and variable operating expenses are estimated to be $6 million to $8 million per year. This did not take into account possible savings that could be achieved by coordinating the utilization of some of the site’s existing infrastructure and/or staff.

1.2 Coal Gasification Unit

The following is a brief analysis of current gasification technologies’ ability to operate on Powder River Basin (PRB) coal or pet coke fuels.

GE Energy — Slurry Fed Entrained Flow Gasifier — The GE entrained flow slagging gasifier is not the best choice for a high moisture, high ash feedstock such as PRB coal. The original design for the GE gasifier comes from Texaco and is based on gasifying petroleum residues. They are working on a design for this type of feedstock, and are planning to roll out their design by the end of this year. In addition, the GE gasifier is refractory lined, which will need replacement every one to two years, depending upon the properties of the feedstock and the amount of erosion.

ConocoPhillips — Slurry Fed Entrained Flow Gasifier — The ConocoPhillips E-Gas gasifier is also a slurry fed slagging gasifier. The E-Gas gasifier has operating experience with PRB coal. At the LGTI facility that was operated between 1987 and 1995, the E-gas gasifier processed more than 3.5 million tons of PRB coal. The E-Gas design is a two-stage gasification process, which should lend itself to higher efficiencies versus a single stage gasifier. Relative to experience, there is only one E-gas gasifier in operation. It is a 2,200 TPD gasifier at the Wabash River Integrated Gasification Combined Cycle (IGCC) facility. This gasifier is also refractory lined, which will need replacement every one to two years, depending upon the properties of the feedstock and the amount of erosion.
Shell — Dry Feed Entrained Flow Gasifier — The Shell SCGP gasifier is a steam tube membrane wall slagging type gasifier that will provide high carbon conversion and high cold gas efficiency with a dry coal feed. The SCGP was designed with the intent of maximizing heat recovery from the syngas. The membrane wall of the SCGP allows for a layer of slag to build up over the tube surface, protecting it from erosion/corrosion. This allows for a long life with low maintenance. The Shell gasifier can process a wide variety of feedstocks, including PRB.

Lurgi — Dry Feed Moving Bed Gasifier — The Lurgi Moving Bed gasifier is a single-stage moving bed dry ash gasifier. In this gasifier, the temperature at the bottom of the bed is kept below the ash fusion point so the coal ash is removed as a solid. Since the moving bed gasifier has very high cold gas efficiency compared with other gasifiers, a larger portion of the original heating value of the coal appears as chemical energy in the gas as opposed to thermal energy. This makes the moving bed gasifier better for chemical production processes versus other integrated gasification units. Moving bed gasifiers are also much more likely to generate higher levels of organic emissions, such as tars and oils, than entrained-flow and fluidized bed gasifiers, which consequently will impact environmental control requirements and possibly emissions. The Lurgi gasifier has the ability to operate on a wide variety of feedstocks, including PRB. The Lurgi gasifier has been utilized at Basin Electric’s Great Plains Synfuels Plant in North Dakota. The feedstock for this facility is a North Dakota lignite. The Lurgi and BGL gasifiers are refractory lined and will need refractory replacement every one to two years depending on the properties of the feedstock and the amount of erosion.

British Gas/Lurgi (BGL) — Dry Feed Moving Bed Gasifier — The BGL gasifier was developed by British Gas and Lurgi during the 1970s. It is similar to the Lurgi gasifier, but it has been designed for slagging operation. This gasifier has the ability to operate on a wide range of feedstocks, including PRB.

It is the consultants’ opinion that the Shell or Lurgi gasifiers would be most effective in meeting the customer’s needs. This is due to the current development status, size of typical unit, and experience level of these technologies. Capital cost estimates for gasification units in the size needed for this application ranged from $45 million to $55 million with annual operating costs in a range similar to that of the CFB combustor ($6 million to $8 million per year).

2.0 ALTERNATIVE FUEL OPTIONS

There were two primary fuel options to be considered, coal and fuel grade petcoke. The consultants evaluated the feasibility and economics of these two options to fuel the process heat requirements at the customer’s plant.

2.1 Fuel and Transportation

Coal is generally a significantly cheaper fuel than natural gas on a delivered basis. For most areas of the United States, coal can be delivered to a facility in the range of about $1.25 to $3.50 per million Btu depending on transportation and logistics. This is the major advantage of coal. Natural gas is in the range of $5.50 to more than $9 per mcf (an mcf of natural gas is roughly equivalent to 1 million Btu of coal).

The biggest disadvantage of coal is the cost of meeting environmental requirements in terms of capital plant equipment. The environmental regulations passed since the 1970s have added significant cost to the development of both utility and industrial coal-fired plant applications.

2.1.1 Transportation

Transportation is a large component of delivered coal cost, particularly for Western coal. The current delivered cost of coal in the eastern and western United States, including the coal price and transportation component is shown in Figure 1.
Transportation rates for coal are set by the railroads based on a number of parameters, including distance, volume delivered, train size (number of cars), loading and unloading times, and, to some extent, whether the customer is captive to one railroad. Large customers, such as electric utility plants that take large annual volumes of coal, often use their own rail cars and have state-of-the-art fast unloading facilities. These large electric plants typically have rates much lower than small customers who rely on a few rail cars at a time, use relatively small annual volumes of coal, and typically don’t have the ability to unload quickly or efficiently. However, there is a way for a small customer to take advantage to an extent of a larger customer’s economics. Many of the electric utilities that burn coal are willing to help industrial customers with coal needs, especially if that industrial is a customer for electric power. While this is not always the case, it is worth exploring.

In the current PRB transportation environment, utility customers in general are not receiving the quantities of coal purchased for delivery to their power plants. This situation is due to high demand for PRB coal, which has in turn stretched two railroads’ (Union Pacific and Burlington Northern Santa Fe) resources to the limit. In the spring of 2005, several events caused outages in transportation from the PRB resulting in a coal shortfall to the power plants of between 15 million and 20 million tons. Since capacity was stretched to the limit, the ability to recover from this shortfall was limited. Continued increasing demand for PRB coal and continued railroad capacity limitations have created an ongoing problem getting required shipments from the PRB. The consultants feel that it will take all of 2006 for the railroads to recover and make up the shortfalls, then be in a position to respond to increased demand. Because of these conditions, most utilities are not able to provide coal to industrials. When the railroads return to a more normal level of service, utilities will likely consider sales to industrial customers.

Figure 1: The transportation component and coal price for an Eastern compliance coal (12,500 Btu/pound, 1.2 pounds SO₂/mmBtu) and for a western sub-bituminous compliance coal (8,800 Btu/pound, 0.80 pounds SO₂/mmBtu).
The closest electric utility plant that burns coal to the customer’s plant is approximately 50 miles away. This plant burns sub-bituminous PRB coal shipped from Wyoming. This would be an ideal coal since PRB coal is the most economical coal type in the United States currently. Coal from the utility plant could be economically trucked to the customer’s plant since the distance is relatively short.

The other fuel option is petroleum coke. There are three petcoke producers within trucking distance of the plant. These are discussed below. However, the petcoke could possibly be transported by rail in small lots; the cost of doing this would be comparable to trucking at the distances that are involved.

2.1.2 Coal

Table 1 shows the current delivered coal costs to the nearby utility plant as well as an estimate for transportation and f.o.b. mine price.

<table>
<thead>
<tr>
<th>Supplier</th>
<th>Mine</th>
<th>Tons</th>
<th>Btu/lb</th>
<th>% Sulfur</th>
<th>% Ash</th>
<th>Delivered Cost ($/mmBtu)</th>
<th>Delivered Cost ($/Ton)</th>
<th>Estimated Rail Rate ($/Ton)</th>
<th>Estimated FOB Mine ($/Ton)</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>AA</td>
<td>1600</td>
<td>8,785</td>
<td>0.23</td>
<td>5.05</td>
<td>$0.96</td>
<td>$16.91</td>
<td>$10.24</td>
<td>$6.67</td>
</tr>
<tr>
<td>B</td>
<td>BB</td>
<td>400</td>
<td>8,578</td>
<td>0.26</td>
<td>4.45</td>
<td>$0.88</td>
<td>$15.15</td>
<td>$10.24</td>
<td>$4.91</td>
</tr>
<tr>
<td>C</td>
<td>CC</td>
<td>900</td>
<td>8,853</td>
<td>0.24</td>
<td>5.43</td>
<td>$0.93</td>
<td>$16.52</td>
<td>$10.24</td>
<td>$6.28</td>
</tr>
<tr>
<td>D</td>
<td>DD</td>
<td>400</td>
<td>8,762</td>
<td>0.20</td>
<td>4.58</td>
<td>$1.09</td>
<td>$19.08</td>
<td>$10.24</td>
<td>$8.84</td>
</tr>
<tr>
<td>Totals</td>
<td></td>
<td>3300</td>
<td>8,776</td>
<td>0.23</td>
<td>5.02</td>
<td>$0.96</td>
<td>$16.85</td>
<td>$10.24</td>
<td>$6.61</td>
</tr>
</tbody>
</table>

Table 1

Table 2 shows the market for PRB coal equivalent to the coal that the utility plant is receiving.

<table>
<thead>
<tr>
<th>Coal Type (mmBtu/lb)</th>
<th>Sulfur Content (Lbs SO2/mmBtu)</th>
<th>FOB Mine Price ($/Ton)</th>
</tr>
</thead>
<tbody>
<tr>
<td>8,800</td>
<td>0.8</td>
<td>$16.00</td>
</tr>
<tr>
<td>8,400</td>
<td>0.8</td>
<td>$14.00</td>
</tr>
</tbody>
</table>

Table 2: Current Wyoming PRB coal prices (as of 2/27/2006)

It is important to understand that market dynamics and price volatility is due to: (1) the run-up in oil and natural gas prices; and (2) the constraints on coal transport both in the western and eastern United States. It is likely that if coal is made available from the nearby utility plant, it will be near the current market price. Long term, most forecasts expect the prices for 8800 Btu PRB coals to be in the $10 to $12 range or less; 8400 Btu PRB coal likely will be in the $8 to $10 range or less. Table 3 shows an estimate of the costs of PRB delivered to the customer’s plant.

<table>
<thead>
<tr>
<th>Heat Content (Btu/lb)</th>
<th>Lbs SO2/ (mmBtu)</th>
<th>FOB Mine Rate ($/Ton)</th>
<th>Rail Rate ($/Ton)</th>
<th>Coal Handling/ Unloading ($/Ton)</th>
<th>Trucking to Site ($/Ton)</th>
<th>Delivered ($/Ton)</th>
<th>Delivered ($/mmBtu)</th>
</tr>
</thead>
<tbody>
<tr>
<td>8,800</td>
<td>0.8</td>
<td>$16.00</td>
<td>$10.24</td>
<td>$2.50</td>
<td>$7.00</td>
<td>$35.74</td>
<td>$2.03</td>
</tr>
<tr>
<td>8,400</td>
<td>0.8</td>
<td>$14.00</td>
<td>$10.24</td>
<td>$2.50</td>
<td>$7.00</td>
<td>$33.74</td>
<td>$2.01</td>
</tr>
</tbody>
</table>

Table 3
The trucking cost is based on a distance of 55 miles from the utility plant to the customer’s plant. These costs also assume that the utility’s unit train rail rate from the Wyoming PRB is used and that the utility would dump the coal using their unit train unloading facility and then allow loading of trucks on their plant site for shipment to the customer. The coal handling and unloading charge is an estimate for the utility dumping the coal and then allowing a contractor to load trucks at on the plant site.

In addition to the above costs, a fuel surcharge may be imposed by the railroad for coal transported from Wyoming. This fuel surcharge has been running between 10 percent and 20 percent of the per ton rail rate. This could add between $1 and $2 per ton to the cost of coal. Some old rail contracts do not have fuel surcharge clauses.

2.1.3 Petroleum Coke (Petcoke)

Another option for the customer’s plant is to utilize petcoke either directly or indirectly to fire the process heaters. There are four facilities relatively close by that produce fuel grade petcoke as shown in Table 4.

<table>
<thead>
<tr>
<th>Petcoke Price</th>
<th>Handling Cost</th>
<th>Trucking to Site</th>
<th>Delivered</th>
<th>Delivered</th>
</tr>
</thead>
<tbody>
<tr>
<td>FOB Plant ($/Ton)</td>
<td>($/Ton)</td>
<td>($/Ton)</td>
<td>($/Ton)</td>
<td>($/mmBtu)</td>
</tr>
<tr>
<td>XX</td>
<td>YY</td>
<td>ZZ</td>
<td>AA</td>
<td></td>
</tr>
<tr>
<td>$28.00</td>
<td>$28.00</td>
<td>$28.00</td>
<td>$28.00</td>
<td></td>
</tr>
<tr>
<td>$2.00</td>
<td>$2.00</td>
<td>$2.00</td>
<td>$2.00</td>
<td></td>
</tr>
<tr>
<td>$12.00</td>
<td>$14.50</td>
<td>$15.50</td>
<td>$18.20</td>
<td></td>
</tr>
<tr>
<td>$42.00</td>
<td>$44.50</td>
<td>$45.50</td>
<td>$48.20</td>
<td></td>
</tr>
<tr>
<td>$1.50</td>
<td>$1.59</td>
<td>$1.63</td>
<td>$1.72</td>
<td></td>
</tr>
</tbody>
</table>

Table 4

Depending upon the availability of petcoke and the type of process used, (e.g. a CFB, coal gasification unit, or other), petcoke could be burned as a stand alone fuel or in a blend with sub-bituminous coal.

3.0 ECONOMIC EVALUATION

3.1 Annual Fuel Cost Comparison

Using the respective costs of fuel estimated for the customer’s plant, a comparison of the annual fuel costs show that coal can have significant savings over natural gas (see Table 5).

<table>
<thead>
<tr>
<th>Fuel Type</th>
<th>Usage Rate</th>
<th>Heat Content</th>
<th>Natural Gas</th>
<th>Coal</th>
<th>Fuel Price</th>
<th>Equiv Price</th>
<th>Annual Use</th>
<th>Annual Fuel Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Natural Gas</td>
<td>500</td>
<td>1,025</td>
<td>11,707,317</td>
<td>-</td>
<td>$7.00</td>
<td>$7.35</td>
<td>4,380,000</td>
<td>$32,193,000</td>
</tr>
<tr>
<td>Coal</td>
<td>500</td>
<td>8,800</td>
<td>-</td>
<td>681</td>
<td>$36.00</td>
<td>$2.05</td>
<td>4,380,000</td>
<td>$8,979,000</td>
</tr>
</tbody>
</table>

Table 5

The fuel savings from burning coal versus natural gas can be substantial (more than $23 million per year). Table 5 uses an average natural gas price of $7 per mcf and an average coal price of $36 per ton delivered. Additional costs of burning coal, such as coal handling, ash disposal and environmental expenses, are not factored in.

Blending the coal with petcoke could provide some additional fuel cost savings as shown in Table 6.
3.2 Long-Term Economic Analysis

In order to provide an assessment of the long-term economic benefits of switching from natural gas to coal, a financial model was developed. The analysis utilized the H&A 20-year forecast for PRB coal and the Energy Information Administration (U.S. Department of Energy) price forecast for natural gas.

The financial analysis includes a net present value calculation based on an up front capital expenditure of $55 million (for boiler and coal handling modifications) and increased annual operation and maintenance expenses of $7 million, escalating at 3 percent per year. Using these assumptions, the payback period is 30 months and the internal rate of return is calculated to be 33.9 percent. The IRR and net present value clearly demonstrate a significant benefit to pursuing this project in more detail. Table 7 shows the results of this comparison.
<table>
<thead>
<tr>
<th>Description</th>
<th>2019</th>
<th>2020</th>
<th>2021</th>
<th>2022</th>
<th>2023</th>
<th>2024</th>
<th>2025</th>
</tr>
</thead>
<tbody>
<tr>
<td>MMBTUS REQUIRED</td>
<td>4,380,000</td>
<td>4,380,000</td>
<td>4,380,000</td>
<td>4,380,000</td>
<td>4,380,000</td>
<td>4,380,000</td>
<td>4,380,000</td>
</tr>
<tr>
<td>PRB COAL FORECAST (1)</td>
<td>$3.34</td>
<td>$3.43</td>
<td>$3.53</td>
<td>$3.63</td>
<td>$3.74</td>
<td>$3.84</td>
<td>$3.96</td>
</tr>
<tr>
<td>NATURAL GAS FORECAST (2)</td>
<td>$5.49</td>
<td>$5.49</td>
<td>$5.62</td>
<td>$5.69</td>
<td>$5.76</td>
<td>$5.87</td>
<td>$5.99</td>
</tr>
<tr>
<td>ANNUAL COST, PRB COAL</td>
<td>$14,613,950</td>
<td>$15,029,183</td>
<td>$15,458,492</td>
<td>$15,902,354</td>
<td>$16,361,264</td>
<td>$16,835,730</td>
<td>$17,326,281</td>
</tr>
<tr>
<td>ANNUAL COST, NATURAL GAS</td>
<td>$24,046,200</td>
<td>$24,046,200</td>
<td>$24,615,600</td>
<td>$24,922,200</td>
<td>$25,228,800</td>
<td>$25,710,600</td>
<td>$26,236,200</td>
</tr>
<tr>
<td>INVESTMENT REQUIRED (3)</td>
<td>$9,432,250</td>
<td>$9,017,017</td>
<td>$9,157,108</td>
<td>$9,019,846</td>
<td>$8,867,536</td>
<td>$8,874,870</td>
<td>$8,909,919</td>
</tr>
<tr>
<td>SAVINGS, REL TO NAT GAS</td>
<td>$9,432,250</td>
<td>$9,017,017</td>
<td>$9,157,108</td>
<td>$9,019,846</td>
<td>$8,867,536</td>
<td>$8,874,870</td>
<td>$8,909,919</td>
</tr>
</tbody>
</table>

### RESULTS SUMMARY

<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>NPV (20 Yr, DiscRate = 10%)</td>
<td>$49,344,773</td>
</tr>
<tr>
<td>PAYBACK (MONTHS)</td>
<td>32</td>
</tr>
<tr>
<td>IRR</td>
<td>28.0%</td>
</tr>
</tbody>
</table>

Table 7: Using these assumptions, the net present value is almost $50 million, the payback period is 32 months, and the internal rate of return is 28%. These financial results clearly demonstrate that there are significant benefits to pursuing this project in more detail, and the client is doing so.

### 4.0 ENVIRONMENTAL REVIEW

This section provides a review of the potential Industrial Boiler MACT Rule requirements that would be imposed should Oneok switch from natural gas-fired heaters to coal or petcoke fueled units.

#### 4.1 Applicability

Boilers (or process heaters) are only subject to the Boiler MACT if they are located at, or are part of, a major source of hazardous air pollutants (HAPs). A major source is defined as any stationary source or group of stationary sources located within a contiguous area and under common control that has the potential to emit 10 tons per year (TPY) of a single HAP or 25 TPY or any combination of HAPs. Therefore, it is possible that the existing natural gas-fired boilers may already be subject to the Boiler MACT Rule.

However, if the boilers are not subject to the Boiler MACT, they would be if converted to burn coal. For example, Unit 1 has a boiler heat input of 112 MMBtu/hr. Assuming this boiler burns a low chlorine western coal (e.g. 200 ppm chlorine, 8,500 Btu/pound HHV) the potential HCl emissions would be approximately 10 TPY for Unit 1 alone. All boilers combined would easily exceed the 10 TPY limit for HCl. In our experience, any facility with multiple coal-fired boilers easily trips on HCl and is subject to the Industrial Boiler MACT. That would be the case for Oneok.
4.2 Emission Limits

Since the converted boilers would be subject to the Boiler MACT, they would be imposed with emission limits for particulate matter (PM), mercury (Hg), hydrogen chloride (HCl), and possibly carbon monoxide (CO). The magnitude of these limits is determined by subcategory the boilers fall into. The boilers would fall into the large (any boiler with a heat input greater than 10 MMBtu/hour), solid fuel (any unit that burns coal, TDF, wood, etc.) subcategory. The only unknown is whether or not the boilers would be classified as “existing” or “new or reconstructed.” This is important because, as shown in Table 8, the emission limits are more severe for “new or reconstructed” boilers versus “existing boilers.”

<table>
<thead>
<tr>
<th>Source</th>
<th>Subcategory</th>
<th>Particulate Matter 1 (lb/MMBtu)</th>
<th>Total Selected Metals (lb/MMBtu)</th>
<th>Mercury (lb/TBtu)</th>
<th>HCl (lb/MMBtu)</th>
<th>CO (ppm @ 3% O2)</th>
</tr>
</thead>
<tbody>
<tr>
<td>New or Reconstructed</td>
<td>Solid Fuel, Large Unit</td>
<td>0.025</td>
<td>or 0.0003</td>
<td>3</td>
<td>0.02</td>
<td>400</td>
</tr>
<tr>
<td>Existing</td>
<td>Solid Fuel, Large Unit</td>
<td>0.07</td>
<td>or 0.001</td>
<td>9</td>
<td>0.09</td>
<td>---</td>
</tr>
</tbody>
</table>

1Particulate matter standards are surrogates for the total selected metals emission limits set by the MACT. Subject sources have the option of complying with the particulate matter standard in lieu of the total selected metals standard.

Table 8

A boiler or process heater is considered reconstructed when it meets the criteria defined in 40 CFR 63.2:

Reconstruction, unless otherwise defined in a relevant standard, means the replacement of components of an affected or a previously nonaffected source to such an extent that:

1. The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable new source; and
2. It is technologically and economically feasible for the reconstructed source to meet the relevant standard(s) established by the administrator (or a state) pursuant to section 112 of the act. Upon reconstruction, an affected source, or a stationary source that becomes an affected source, is subject to relevant standards for new sources, including compliance dates, irrespective of any change in emissions of hazardous air pollutants from that source.

Obviously, this is not a straightforward determination and eventual classification would severely affect the applicable emission limits and the required air pollution control equipment.

In addition, an analysis was done to determine the Prevention of Significant Deterioration (PSD) thresholds for the criteria pollutants and the expected potential to emit (PTE) from both processes.

The timeline to apply for, receive and resolve any disputes for a PSD permit needs to be recognized. Typically it takes three to six months prepare the PSD application, which includes dispersion and visibility modeling. The state agency will take nine to 12 months to review the application, draft the permit, hold public hearings and address
comments. After permit issuance, this is an excellent likelihood that an intervener group, such as the Sierra Club, would appeal the permit. Resolving all appeals can take one to three years. The nature of the appeal determines whether or not construction can proceed while the legal issues are resolved.

4.3 Air Pollution Control Equipment

Regardless of whether the boilers are classified as “reconstructed” or “existing” and regardless of the type of coal to be burned, the boilers will be required to have air pollution control equipment to meet emission limits. Preliminary evaluations of the air pollution control equipment that might be needed:

SO\(_2\) and NO\(_x\)
Some of the controls that will likely need to be installed to achieve the desired BACT levels for coal include selective catalytic reduction (SCR) and dry flue gas desulfurization (FGD). SCR is used to lower NO\(_x\) emissions and FGD to lower SO\(_2\) emissions. Additionally, operating costs will include additional staff to operate the controls and costs for catalyst replacement every few years.

Particulate Matter
Pollution control equipment will absolutely be required to control PM emissions. A fabric filter is the likely choice for PM control equipment due to the potential need for sorbent injection and/or dry scrubbing ahead of the fabric filter. An Electrostatic Precipitator (ESP) is not a likely choice because it can limit the performance of sorbent injection and does not provide the fuel flexibility of a fabric filter. A fabric filter could be provided for each boiler or common fabric filter(s) could be provided to treat multiple boilers.

Mercury
The control equipment necessary for Hg control is dependent on whether the boiler is classified as “reconstructed” or “existing,” the type of coal burned, and the temperature of the flue gas at the pollution control device(s).

If the boilers are classified as “reconstructed,” the Hg emission limit is relatively strict at 3.0 pounds/TBtu. At a minimum, a sorbent (e.g. activated carbon) injection system, coupled with the fabric filter installed for PM control, would be required, especially if the boilers burn a western coal (which typically have a lower mercury content than bituminous coals). If the boilers are classified as “reconstructed” and burn eastern bituminous coal, a wet or dry scrubber may be required. If the boilers are classified as “existing,” the Hg emission limit is relatively lax at 9.0 pounds/TBtu. Many western coals have mercury concentrations less than this limit and, therefore, may not require any Hg control equipment. For other coals, sorbent injection may be necessary.

Flue gas temperature at the air pollution control equipment influences the ability to control Hg emissions. As the temperature increases above 300 degrees, the ability to control mercury is lessened and in turn the probability of adding pollution control equipment is increased. Therefore, the boiler conversion to coal-firing should consider including economizer and/or air heater retrofits to ensure optimum flue gas temperature for Hg control.

Hydrogen Chloride
As with Hg, the control equipment necessary for HCl control is heavily dependent on whether the boiler is classified as “reconstructed” or “existing” and is dependent on the type of coal burned. Possible control technologies include sorbent (e.g. hydrated lime) injection or a dry or wet scrubber.

An option to installing control equipment for HCl, is to try and demonstrate compliance via the health-based risk alternative of the Boiler MACT Rule. This alternative allows a facility to emit HCl emissions above the stack emission limit as long as a facility can demonstrate that the ambient concentration of HCl at the property fence line is less than a certain value. Most clients for whom we have conducted studies have been able to meet the HCl health-based alternative emission limit.