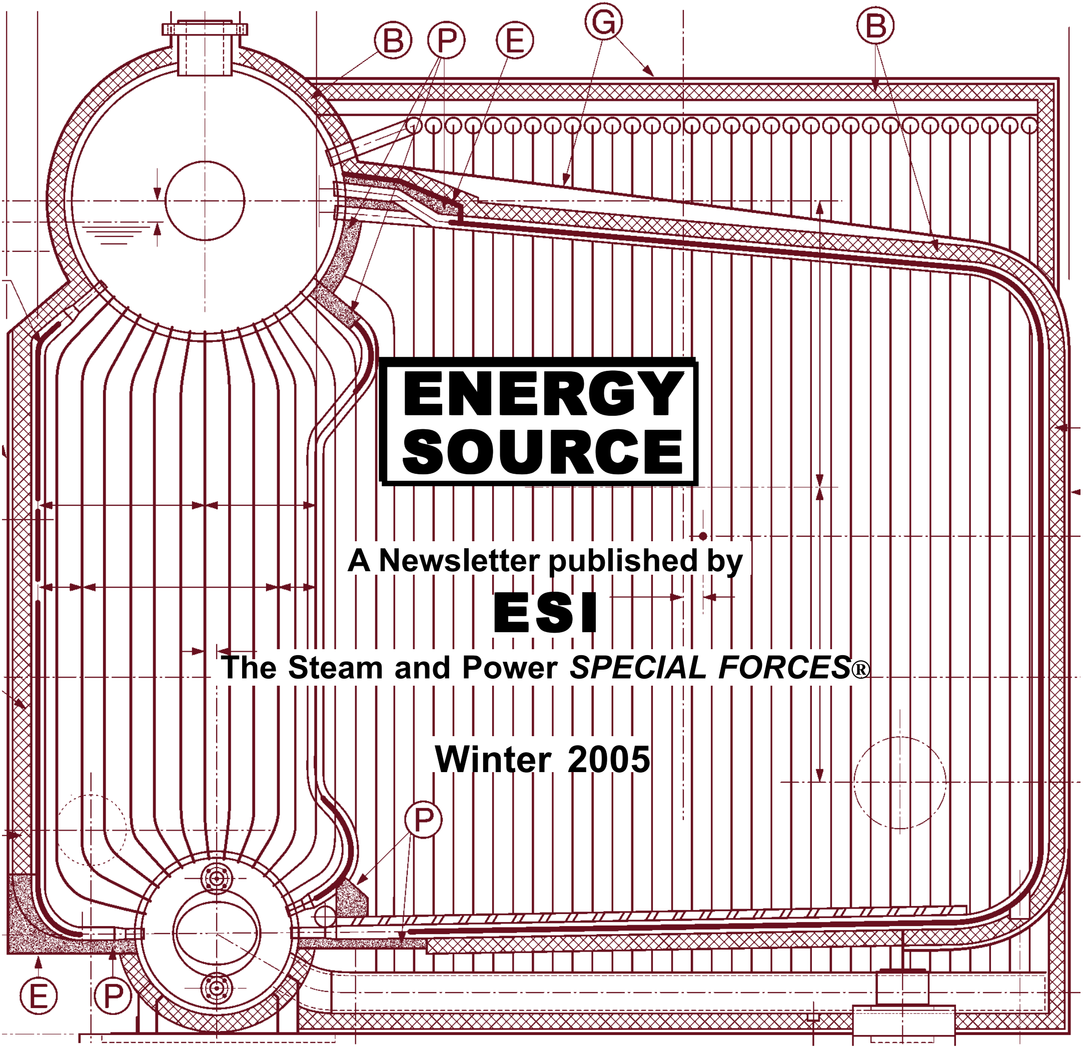
ENERGY SOURCE

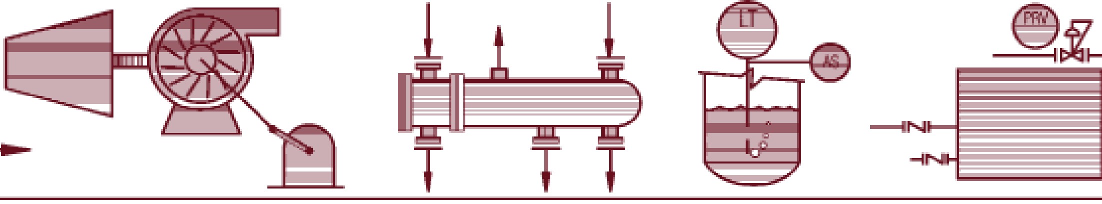
A Newsletter published by

ESI

The Steam and Power *SPECIAL FORCES*®

Winter 2005





CAN YOU AFFORD NOT TO SWITCH TO COAL?

By: William L. Reeves, P.E., ESI

In the last issue of *ENERGY SOURCE*, ESI discussed the current and projected future cost differential between natural gas and coal, and its recent effect on the direction of the utility industry. This significant cost difference is the economic driving force for recent renewed interest in designing and building new coal-fired steam and power plants, the magnitude of which has not been experienced for over 20 years in the industrial and non-regulated utility markets.

In recent discussions with many of our large industrial clients, it has become clear that in general, industry has become somewhat immune to the potential favorable economics of burning coal to provide their steam and power needs. The consistent and systematic promulgation of new environmental regulations over the past 25 years has negatively affected industry's perception of the feasibility of coal firing. Industrial clients today simply don't believe that a new coal-fired process steam and power plant can be permitted and built to replace gas-fired assets and yield a favorable rate of return. There is no doubt that the coal-fired power plant of today has a lot more emission control technology; however, the life cycle fuel cost differential is still significant enough to overcome the capital and operating costs of these required emission control technologies. Obviously, the cost of emission control equipment, coupled with inflation, makes coal-fired steam plants much more expensive today, and the return on investment is not as good as it was in the early 80's, but it is still significant. If one is willing to seek an environmental permit with the appropriate emission control technologies, environmental permitting is not difficult.

This article will outline some of the major decisions required in the consideration of a new coal-fired power plant and provide some insight into the realistic coal-firing technologies available, emissions control technology requirements, and representative capital cost and economics. Our goal in this article is to provide end users some basic facts that will help reduce the negative stigma associated with the coal-fired alternative to high natural gas and oil prices.

BUDGETARY CONCEPTUAL ANALYSIS

The design of any power plant begins with the selection of the specific fuel(s) to be utilized and the technology that is to be employed. Ultimately, one is seeking the lowest life cycle cost; therefore, a detailed analysis must be done regarding the potential combinations of fuel, capital, and operating costs to make this determination. This can be a somewhat complex analysis, but in simple terms, the following factors are considered:

- Current and future projected facility utility requirements
- Current and projected cost of utilities
- Delivered fuel cost, ultimate analysis, and physical properties
- Environmental permit emissions and control equipment requirements
- Budgetary capital cost and economic analysis

Continued on Page 2

ENERGY SOURCE

The *ENERGY SOURCE* is published quarterly for customers, employees, and friends of ESI Inc. of Tennessee.

ESI is the Steam and Power *SPECIAL FORCES®* providing clients with innovative, cost-effective, and environmentally-friendly solutions.

If you have any suggestions or comments about the newsletter feel free to call us at 770-427-6200 or e-mail us at energysource@esitenn.com.

Deanna White
Managing Editor

CAN YOU AFFORD NOT TO SWITCH TO COAL?... *Continued from Page 1*

If this budgetary analysis is done for the potential combinations of fuels and technologies, a clear winner generally emerges which sets the direction for a more detailed technical and economic analysis of the specific fuel and technology to be considered. In many cases coal comes out as the winner.

Facility Utility Requirements

This initial step is simply a determination of the facility requirements for steam and power including any operational and redundancy requirements. What is the annual average hourly steam production, and winter and summer peak loads? What is the annual average hourly power purchase and how does it vary by time of day, month, or season? How critical is redundancy in certain systems? What is the most inexpensive way to solve the back-up and redundancy dilemma? With whom and how am I going to staff this potential new power plant facility? These are the types of questions that must be answered in this phase of the analysis so that the new steam plant size, type, and operating parameters can be bracketed for analysis.

Current and Projected Cost of Utilities

After the facility utility requirements are understood, the next step in the analysis is to determine the historical, current, and projected future operating and maintenance costs of the facility. This includes the unit cost and calculated total annual cost of fuel, power, chemicals, water, waste treatment, maintenance, operating personnel, etc. The combination of these unit costs and the facility requirements provide the data to calculate all the current O&M costs and assist in projecting future costs which define the potential opportunity for savings by switching to coal for process steam, and possibly cogenerating power.

Delivered Fuel Cost, Ultimate Analysis, and Physical Properties

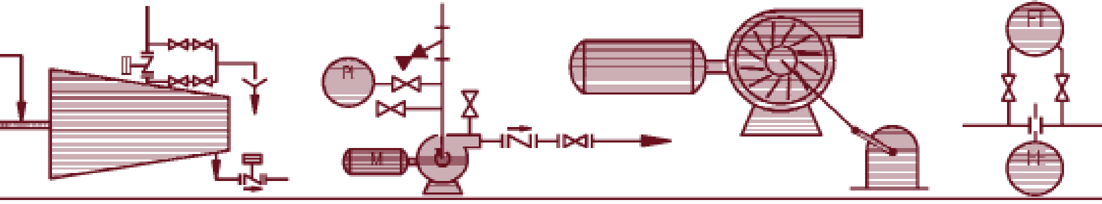
One has many choices regarding the specific coal to burn; however, generally, the decision is driven by the delivered fuel costs and the associated plant capital O&M cost. The sulfur and nitrogen contents are critical because these will determine the specific emissions clean-up technology required, and the operating and maintenance costs. Physical properties such as sizing and ash fusion temperatures will affect such items as coal preparation, firing equipment used, and furnace/boiler design.

Powder River Basin (PRB) coal is much less expensive than Eastern and Midwestern bituminous coals, and is very low in sulfur. This coal would appear to be a natural choice for companies switching to coal; however, PRB offers some challenges that restrict its viability for installations with a heat input less than 100-150 mmbtu per hour. The handling and storage of PRB generates excessive fines that make stoker firing a challenge; consequently, PRB is predominantly fired in a Pulverized Coal (PC) or Circulating Fluid Bed (CFB) boiler.

Currently, depending on your location, modified stoker coal and occasionally, even mine run coal can be very expensive due to rail transportation issues resulting from the recent high demand for coal. It is expected that as the rail transportation issues get resolved, coal pricing should retreat somewhat as market forces restore the supply and demand balance. Also, mines that were closed down due to low demand and cheap coal prices can now consider reopening.

Now that New Source Performance Standards (NSPS) mandate a minimum 90% sulfur removal, burning low-sulfur coal is not as big an opportunity as it used to be. The decision to burn low-sulfur versus high-sulfur coal is now an economic decision, considering the fuel cost differential compared to the sulfur capture equipment, and reagent capital and O&M costs.

Continued on Page 3



Environmental Permit Emissions and Control Equipment Requirements
Federal environmental regulations are now well-defined for all sizes and types of coal-fired boiler installations; however, state and local regulations can often mandate even more stringent emission requirements. Applicable Federal regulations include New Source Performance Standards (NSPS) and Maximum Allowable Control Technology (MACT) standards. The potential emission control technologies evaluated and selected ultimately come down to consideration of the boiler heat input, emissions removal efficiency requirements, and capital and O&M costs. Potential credit for emissions emitted by existing equipment that can be shut down can also dramatically affect this decision.

Sulfur dioxide (SO2) can be controlled with several technologies; however, two of the primary technologies used today are a Circulating Fluidized Bed (CFB) boiler with limestone added to the bed for in-bed SO2 capture, or the use of a combination SO2 spray dryer and baghouse when pulverized coal or coal stokers are used. SO2 reduction is mandated at a minimum of 90% with a maximum emission level of 1.2 lbs of SO2 per mmbtu boiler heat input.

CFB boilers have lower nitrogen oxide (NOx) emissions than other firing technologies, and can often be permitted using Selective Non-Catalytic Reduction (SNCR) technology in conjunction with the CFB boiler. Stoker-fired boilers and PC boilers with low NOx burners can use either SNCR or SCR technology for final NOx control, depending upon the final permit requirements.

An electrostatic precipitator (ESP) or a baghouse is normally used for particulate control; however, baghouses tend to be used more frequently because of better SO2 removal reagent utilization due to SO2 capture in the bag filter cake.

Budgetary Capital Cost and Economic Analysis
Many of the above issues are interrelated; therefore; the only viable method to simultaneously evaluate the differential project economics associated with different fuel, capital, and O&M costs is to develop an economic model that allows one to change variables where the corresponding change to the economic proforma is automatically calculated. The development of this model, combined with budgetary capital cost estimates for the different equipment options, allows one to consider the O&M cost differences, as well as to determine which combination of coal, firing technology, and environmental equipment yields the best rate of return. Once this decision is made, one can focus on developing a tighter capital cost estimate for the selected option and then fine tune the economic proforma.

The ultimate goal for the budgetary conceptual analysis is to validate the selected option capital cost and economic proforma, which will lead to a final decision regarding the project funding.

COAL CONVERSION PROJECT EXAMPLE
The following analysis will provide some insight into the decision process outlined above. This example represents a typical coal conversion project analysis recently conducted by ESI.

XYZ is a Midwestern process industry that has an annual average hourly steam flow requirement of 150,000 pph at 150 psig saturated. The winter peak load is 160,000 pph, and the minimum summer load is generally over 100,000 pph. The plant average hourly power use is about 8 megawatts, which currently costs about $45.00 per MW including both demand and energy charges. XYZ currently fires natural gas at an average cost of $6.00 per mmbtu and uses #2 fuel oil for back-up.

Continued on Page 4

CAN YOU AFFORD NOT TO SWITCH TO COAL?... *Continued from Page 3*

The new coal-fired boiler system is designed for 160,000 pph steam capacity. In our analysis, both a 150 psig saturated and 650 psig/750ºF superheated steam system are evaluated. The high pressure and temperature option provides for the net production of 4,950 kwh of power through the use of a backpressure steam-turbine generator (STG) exhausting at 150 psig saturated to the process steam header.

PRB coal is chosen as the fuel because low-sulfur PRB coal can currently be delivered to the site for about $2.84 per mmbtu, whereas a medium-sulfur modified stoker bituminous costs over $3.00 per mmbtu. This particular facility would receive the coal by truck, and a truck unloading system is less expensive than rail. However, the decision to provide for rail or truck deliveries is mainly a transportation cost issue. A coal storage silo with 7 days storage is used to provide for site cleanliness and first-in/first-out coal usage. A complete pneumatic ash handling system is provided which includes a load-out silo with 3 days capacity.

Because of the relatively small size of this new coal-fired boiler, a CFB boiler installation will be much more expensive than a PC- or stoker-fired system, even though the PC or stoker will require more emission control equipment. Consequently, a pulverized coal-fired boiler and low NOx burner technology is chosen, which requires a dry scrubber and baghouse for SO2 and particulate emissions control. Because the existing boilers fire natural gas and have low NOx burners, the increase in potential NOx emissions will exceed the maximum annual emissions level of 40 tons per year, thus requiring a Prevention of Significant Deterioration (PSD) permit and the application of Best Available Control Technology (BACT). This BACT analysis will determine whether Selective Catalytic Reduction (SCR) or Selective Non-Catalytic Reduction (SNCR) technology will be required for NOx. For this size boiler, the SCR requirement will add about $1.5 million in capital cost. The environmental permit application can include an allowance for the existing boilers to remain fully capable for back-up in case of an unforced outage of the coal-fired boiler system.

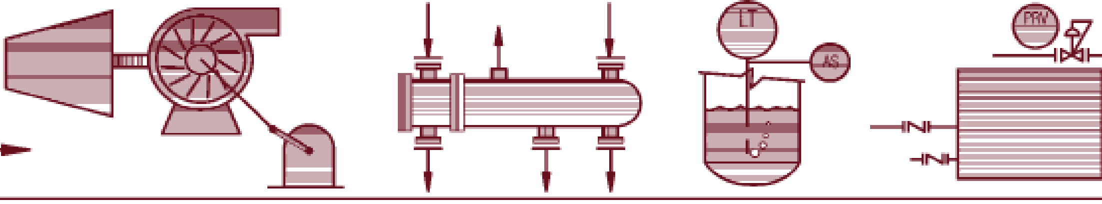
The new facility includes all new waterside auxiliaries including deaerator, boiler feedwater pumps, water treatment, and chemical feed systems. A new Distributed Control System (DCS) is also included. Table I provides a summary of the economic analysis for the following three options:

- Option #1 – 150 psig saturated boiler with dry scrubber, baghouse, and SNCR system
- Option #2 – Same as Option #1 with STG operating at 650 psig/750ºF and producing about 4,950 kwh net of additional parasitic power requirements
- Option #3 – Same as Option #2 with SCR instead of SNCR for final NOx control

Table I. Economic Analysis Summary

Parameter	Option #1	Option #2	Option #3
Hourly Net Power Generated (kwh)	0	4,950	0
Budgetary Capital Cost ($000)	20,000	24,000	21,500
Annual Operating Savings ($000)	4,230	5,380	4,230
IRR on 100% Equity (%)	16.5	17.5	15.2
NPV of 100% Equity (%)	9,720	13,280	8,740
IRR on 20% Equity (%)	63.5	67.6	58.5

Continued on Page 5



CAN YOU AFFORD NOT TO SWITCH TO COAL?... *Continued from Page 4*

All economic proformas consider an average hourly steam flow of 150,000 pph, include all operating and maintenance costs, taxes and depreciation, and use a discount rate of 8% for the net present value (NPV) calculation.

Although the analysis in Table I provides for a modest internal rate of return (IRR) on a 100% equity investment, the annual operating cost savings and the NPV are substantial. This operating cost reduction makes XYZ's products more competitive, as well as providing for long-term stability and predictability in their future energy costs. In the cogeneration case, XYZ gains even further independence in its energy policy by purchasing less power from the local utility. The other important factor about this type of project is that the risk of not making the predicted ROI is much lower than a core business-related project for XYZ where market assumptions have to be realized. The manufacturing facilities that switched to coal in the 70's and early 80's, and have continued to satisfy their steam and power requirements by burning coal, are now enjoying a huge operating cost advantage over their direct competitors.

This typical coal conversion project analysis should shed some light and eliminate concern regarding the economic viability of firing coal, even when one considers all of the state-of-the-art emission clean-up technology necessary to make environmental permitting a virtual certainty. If you would like for ESI to perform an evaluation of the technical and economic viability of switching your facility to coal, please contact Bill Reeves or Jay Garrett at 770-427-6200.