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ECONOMIC CONSIDERATIONS IN CONVERTING FROM OIL/GAS FIRING TO COAL

John G. Rau

Ultrasystems, Inc.
Irvine, California

ABSTRACT

Economic considerations involved in fuel conversion such as from oil and/or gas firing to coal include investment costs for new facilities and equipment (including air pollution control equipment), operation and maintenance costs, and purchased fuel costs. This paper presents an analytical approach to assessing the cost effectiveness of fuel conversion in terms of the annual net cost of conversion, the equivalent annual number of barrels of oil saved, and the internal rate of return of the conversion investment. Illustrative numerical examples are presented for typical utility boilers and industrial boiler facilities. A further consideration addressed deals with the impacts of these costs on the overall financial structure of the firm and the ability of the firm to raise the necessary investment capital.

I. OVERVIEW OF COAL CONVERSION ACTIVITIES

By coal conversion in this paper we mean the switching from either oil and/or gas as the primary fuel(s) to coal as the primary fuel in a combustor (boiler, burner, furnace or kiln). Historically, fuel switching has generally tended to be in the other direction, namely, oil/gas conversion. For example, during the late 1960's and early 1970's, while coal-fired powerplants were being converted to oil, utilities were also building new plants to burn oil. Initially, utilities converted to oil for economic reasons; however, more recently, the principal reason for converting to oil has been the requirement to meet strict sulfur emission regulations which the utilities were unable to do using coal. Most of these conversions took place on the East Coast at plants with easy access to ocean and river barge transport.

In 1970, it is estimated (Ref. 1) that only 40% of new boiler orders provided for coal-firing capability. In 1974, however, in response to the natural gas shortages and increased price of oil, 97% of new boiler orders provided for coal-firing capability. Consequently, we see a trend occurring back to coal conversion. It is noteworthy that, according to Reference 2, about 80% of the boilers which were converted from coal to oil can, in time, be re-converted to coal.

The current impetus for coal conversion is caused by the legislative requirements of the Energy Supply and Environmental Coordination Act (ESECA) of 1974 (Public Law 93-319), as amended by the Energy Policy and Conservation Act (EPCA) of 1975 (Public Law 94-163). It is intended that ESECA, by providing the Department of Energy (DOE) with the authority to require the use of coal by existing and future electric utility powerplants and other major fuel burning installations (MFBI's), will result in a significant decrease in the use of petroleum and natural gas and an increase in the use of our most abundant domestic energy resource.

Collectively, ESECA and EPCA provide DOE with the statutory authority to issue a Prohibition Order to an existing facility for the purpose of prohibiting the further use of oil and/or gas as the primary fuel(s). Before such an order can be issued, DOE must determine that the powerplant or MFBI possessed the necessary equipment and capability to burn coal on June 22, 1974, or acquired it thereafter. DOE must assess the existence of certain necessary coal handling facilities and appurtenances such as adequate facilities for the storage of coal, and equipment such as a boiler, unloaders, conveyors, crushers, pulverizers, scales, burners, soot blowers, and special coal burning instrumentation and controls. In addition, DOE must also find that:

(1) the burning of coal at the facility is practicable and consistent with the purposes of ESECA;
(2) coal and coal transportation facilities will be available for the period the order is in effect; and
(3) in the case of a powerplant, the order will not impair the reliability of service in the area served by the converting powerplant.

Prohibition Orders were issued in 1975 affecting 74 powerplant units and were issued in 1977 affecting 18 powerplant units and 28 MFBI combustors.

DOE is also provided with the statutory authority to require powerplants or MFBI's in the early planning process to be designed and constructed so as to be capable of using coal as the primary energy source. This is accomplished through the issuance of a Construction Order. No such order may be issued if DOE finds that (a) in the case of a powerplant, such order is likely to impair the reliability or adequacy of service, or (b) an adequate and reliable supply of coal is not expected to be available. Furthermore, in considering the desirability of issuing such an order, DOE must consider the existence and effects of any contractual commitment for the construction of such facility, and the ability of the owner to recover any capital investment made as the result of a Construction Order. Orders of this type were issued in 1975 affecting 74 new powerplants and were issued in 1977 affecting 18 new powerplants and 27 new MFBI combustors.

II. CONSIDERATIONS AND FACTORS IN COAL CONVERSION INVESTMENT

Major considerations of significance in assessing the willingness and/or overall acceptance of coal conversion include the following:

(1) the difficulties industry will experience with environmental and facility siting regulatory problems
(2) the aversion industry has to using coal

due to the difficulties of handling coal at the plant, the extra personnel required, etc.

(3) the higher rate of return some firms require on a discretionary investment (assuming no DOE order is issued) – especially one which may neither enhance output nor protect production.

(4) the added risks associated with reliability of coal supply to the plant.

Of particular importance are those factors which have a direct effect on costs such as:

(1) combustor size affects costs since costs of coal equipment as well as pollution control equipment are characterized by economies of scale

(2) capacity utilization determines how quickly capital costs are recovered as the result of fuel price savings

(3) coal capability is a factor because, if the unit was designed originally to fire coal, the capital costs of conversion will, most likely, be less than the cost differential between a new gas/oil-firing and a new coal-firing unit

(4) remaining useful life of facility determines the period of time over which the conversion investment can be amortized and thus affects the rate of return on the investment

(5) regional location affects costs primarily through delivered fuel prices

(6) environmental controls imposed through state regulations and Federal New Source Performance Standards affect the costs of the pollution control equipment necessary, which in many cases is the most significant capital cost

(7) new versus existing units for conversion involves the tradeoff between new capital equipment and thus longer amortization period versus modification of used and existing units with perhaps a shorter amortization period

(8) fuel type as determined by sulfur content required, percent ash required, etc. and the means transportation affects the corresponding fuel price differential.

III. BREAKEVEN FORMULATIONS FOR COAL CONVERSION INVESTMENT

In terms of analyzing on an annual basis the investment by a company in coal conversion there are three basic quantities to be considered, namely:

(1) annualized investment cost, which is defined to be

$$\begin{pmatrix}\text{Total investment}\\ \text{cost}\end{pmatrix}\begin{pmatrix}\text{Capital recovery}\\ \text{factor or fixed}\\ \text{charge rate}\end{pmatrix};$$

(2) annual fuel cost differential, which is defined to be

$$\begin{pmatrix}\text{Fuel cost}\\ \text{differential}\\ \text{in } \$/10^6 \text{ BTU's}\end{pmatrix}\begin{pmatrix}\text{Heat rate}\\ \text{in BTU's/}\\ \text{kwhr}\end{pmatrix}\begin{pmatrix}\text{Size}\\ \text{in kw}\end{pmatrix}$$

$$\times\begin{pmatrix}\text{8760 hrs}\\ \text{per year}\end{pmatrix}\begin{pmatrix}\text{Average}\\ \text{capacity}\\ \text{factor}\end{pmatrix};$$

(3) annual operation and maintenance cost differential, which is defined to be

$$\begin{pmatrix}\text{O\&M cost}\\ \text{differential}\\ \text{in } \$/\text{kwhr}\end{pmatrix}\begin{pmatrix}\text{Size}\\ \text{in kw}\end{pmatrix}\begin{pmatrix}\text{8760 hrs}\\ \text{per year}\end{pmatrix}$$

$$\times\begin{pmatrix}\text{Average}\\ \text{capacity}\\ \text{factor}\end{pmatrix}.$$

In the formulation of the annualized investment cost, multiplying the total investment cost by either the capital recovery factor, defined to be

$$\frac{i(1+i)^N}{(1+i)^N-1}$$

where i is the annual discount rate which reflects the worth of capital and N is the number of years over which the investment is amortized, or by the annual fixed (or levelized charge) rate has the effect of amortizing the investment over a specified period of time (generally the remaining useful life of the facility). Typically, the choice of the discount rate is based on the weighted cost of capital as determined according to the sources of capital. For example, consider the following computation:

Capital Source	Percent of Total Capitalization	Capital Cost (%)	Weighted Cost (%)
Mortgage Bonds	50	8.1	4.05
Preferred Stock	15	8.3	1.25
Common Equity	35	15	5.25
			10.55

Therefore, the discount rate used would be 10.55% based on a weighted average cost of new capital.

Another approach would be to use a fixed (or levelized) charge rate as is done by utility companies to compute the annualized investment cost. This rate is chosen as a measure to describe the revenue which must be raised annually to earn a reasonable return on the capital used to purchase equipment, to amortize the equipment over its productive life and to pay requisite income taxes, property taxes and insurance. This rate depends upon the consideration of many factors including the following: the capital structure of the company; the required return on debt, common and preferred stock; the useful life of the equipment and its scrap age value, if any; the formulas used in computing actual and tax depreciation; whether tax savings from depreciation and the investment tax credit are normalized or flowed through; the effective tax rate (combined federal and state); the property taxes. Typically, fixed charge rates range from 20-40 , depending upon the relative importance of the above factors.

In order for the investment in coal conversion to breakeven the following must be true:

$$\begin{pmatrix}\text{Annualized}\\ \text{investment}\\ \text{cost}\end{pmatrix}=\begin{pmatrix}\text{Annual}\\ \text{fuel cost}\\ \text{differential}\end{pmatrix}-\begin{pmatrix}\text{Annual}\\ \text{O\&M cost}\\ \text{differential}\end{pmatrix}.$$

The righthand side of this equation represents the net gain due to fuel price savings.

As an illustration, consider the conversion of 2 800-megawatt boilers requiring flue gas desulfurization (FGD). This conversion is estimated to take place in 1980 at a cost of $804/kw. These boilers are assumed to be operated at 70% capacity over their remaining 20 years of useful life, and have a design heat rate when coal-fired of 9,700 BTU's/kwhr. Assuming a 11% discount rate, this implies a capital recovery factor equal to

$$\frac{(.11)(1.11)^{20}}{(1.11)^{20} - 1} = .12557 \ ,$$

or, equivalently, a fixed charge rate of approximately 12.6%. Therefore,

$$\begin{pmatrix}\text{Annualized}\\ \text{investment}\\ \text{cost}\end{pmatrix} = (1,600,000 \text{ kw}) \begin{pmatrix}\text{\$804 per}\\ \text{kw}\end{pmatrix}$$

$$\times\ (.12557) = \$12,557,564$$

$$\begin{pmatrix}\text{Annual}\\ \text{fuel cost}\\ \text{differential}\end{pmatrix} = \begin{pmatrix}\text{Fuel cost}\\ \text{differential}\\ \text{in \$/10}^6 \text{ BTU's}\end{pmatrix} \begin{pmatrix}\text{9,700}\\ \text{BTU's/kwhr}\end{pmatrix}$$

$$\times \begin{pmatrix}\text{1,600,000}\\ \text{kw}\end{pmatrix} \begin{pmatrix}\text{8,760 hrs}\\ \text{per yr}\end{pmatrix} (.70)$$

$$= (95,168,640) \begin{pmatrix}\text{Fuel cost}\\ \text{differential}\\ \text{in \$/10}^6 \text{ BTU's}\end{pmatrix}$$

$$\begin{pmatrix}\text{Annual}\\ \text{O\&M cost}\\ \text{differential}\end{pmatrix} = \begin{pmatrix}\text{O\&M cost}\\ \text{differential}\\ \text{in \$/kwhr}\end{pmatrix} \begin{pmatrix}\text{1,600,000}\\ \text{kw}\end{pmatrix}$$

$$\times \begin{pmatrix}\text{8,760 hrs}\\ \text{per hr}\end{pmatrix} (.7) = (9,811,200)$$

$$\times \begin{pmatrix}\text{O\&M cost}\\ \text{differential}\\ \text{in \$/kwhr}\end{pmatrix}$$

For breakeven we must then have

$$12,557,564 = (95,168,640) \begin{pmatrix}\text{Fuel cost}\\ \text{differential}\\ \text{in \$/10}^6 \text{ BTU's}\end{pmatrix}$$

$$+\ (9,811,200) \begin{pmatrix}\text{O\&M cost}\\ \text{differential}\\ \text{in \$/kwhr}\end{pmatrix} \ .$$

Figure 1 provides a plot of fuel cost differential versus O&M cost differential using this linear relationship for breakeven. Assuming a 1.4 mill/kwhr O&M cost differential, this implies a fuel cost differential of approximately $1.34 per 10^6 BTU's. An estimated 1980 coal price (Source: Pacific Gas & Electric Co.) is $1.49 per 10^6 BTU's. This implies that in 1980 for breakeven the price of oil must be at least $3.33 per 10^6 BTU's or, approximately $20.31 per barrel, which is comparable to DOE estimates of the 1980 range of oil prices.

IV. OVERALL METHODOLOGY FOR EVALUATION OF COAL CONVERSION ECONOMICS

In the evaluation of the overall reasonableness of coal conversion by utility companies, the Department of Energy (formerly the Federal Energy Administration) utilizes a methodology (see Refs. 7&8) which considers such factors as: boiler size, remaining useful life after conversion, operating capacity both before and after conversion, and derating (i.e., loss of power because of pollution control equipment), if any, estimated fuel prices both before and after conversion; investment costs for both air pollution control equipment and non-air pollution control equipment; O&M cost differential for both air pollution control equipment and non-air pollution control equipment; annual fixed charge rate, or cost of capital if the capital recovery factor is used to obtain the amortized investment cost; annual fuel cost differential; annual fuel consumption by type of fuel both before and after conversion; heat content in BTU's for each type of fuel consumed. These factors are used to compute overall evaluation measures such as:

(1) equivalent annual barrels of oil saved as a result of conversion
(2) annual cost per equivalent barrel of oil saved
(3) change (annual cost differential) in cost per kilowatt-hour of electricity generated
(4) rate of return both before and after taxes from the coal conversion investment.

Tables 1-3 provide an illustration of this methodology applied to the case of converting two boilers with a total 158 MW capacity currently using both natural gas and oil. Table 3 shows that for this example conversion will save approximately 1.355 million barrels of oil per year at a cost to the company of $1.95 per barrel saved (considerably less than the price of a barrel of oil) and at an increase of 3.472 mills per kilowatt-hour generated; however, the rate of return from this particular investment is far from attractive by today's standards as is seen by the 6% before taxes and 3.2% afterwards (using straight line depreciation).

V. FINANCING CONSIDERATIONS

In assessing the overall financial impact of conversion, consideration must be given to those initial investment and annual costs which are incurred as the result of establishing a coal-burning capability. The basic investment costs will consist of those associated with the retrofit of existing and/or acquisition of new air pollution control equipment, and those associated with the acquisition of coal handling equipment and facilities. The basic annual costs will consist of fuel costs, fixed charges for such items as interest, taxes, depreciation, etc., operation and maintenance costs associated with non-air pollution control equipment. Other factors of importance would include the time required to complete conversion, the remaining useful life of the boilers which are converted, and the cost of borrowed capital.

These investment and annual cost factors affect the overall financial structure of a firm in a number of ways. This is best illustrated by examining the potential impacts on the standard financial statements of a firm given by the Balance Sheet and Income Statement. For example, the basic investment costs would affect the investments, property, plant and equipment, and long-term debt (and maybe even the preferred stock and common stock) categories. The operation and maintenance cost items could potentially affect subsequent retained earnings. Fuel costs enable the acquisition of a coal supply and thus potentially will impact the current assets, current liabilities, and retained earnings categories. Fixed charges would potentially affect both current liabilities and retained earnings.

With regard to the Income Statement, investment costs would impact the income taxes paid based on the amount of investment tax credit claimed and, as a result, would affect the firm's net profit after taxes. Both the operation and maintenance costs and the fuel costs would impact the cost of goods sold category and, as a result, the firm's gross profit. Fixed charges would affect the operating expenses, other expenses and income taxes categories and, as a result, would also have a direct effect on the firm's net profit after taxes.

Other considerations which affect the capital aspect of a firm's financial structure are as follows:

(1) growth rate of future sales

The future growth rate of sales is a measure of the extent to which the earnings per share of a firm are likely to be magnified by leverage. In some cases, financing by debt with limited fixed charges should magnify the returns to owners of the stock. On the other hand, the common stock of a firm whose sales and earnings are growing at a favorable rate commands a high price in which case equity financing is desirable. A firm must weigh the benefits of using leverage against the opportunity of broadening its equity base when it chooses between future financing alternatives.

(2) stability of future sales

Sales stability and debt ratios are directly related. With greater stability in sales and earnings, a firm can incur the fixed charges of debt with less risk than it can when its sales and earnings are subject to periodic declines; in the latter instance it will have difficulty in meeting its obligations.

(3) competitive structure of the industry

Debt-servicing ability is dependent upon the profitability as well as the volume of sales; hence, the stability of profit margins is as important as the stability of sales. The ease with which new firms may enter the industry and the ability of competing firms to expand capacity will influence profit margins. A growth industry promises higher profit margins, but such margins are likely to narrow if the industry is one in which the number of firms can be easily increased through additional entry.

(4) asset structure of the industry

Asset structures influence the sources of financing in several ways. Firms with long-lived fixed assets use long-term mortgage debt extensively. Firms whose assets are mostly receivables and inventory whose value is dependent on the continued profitability of the individual firm (for example, those in wholesale and retail trade) rely less on long-term debt financing and more on short-term.

(5) control position and attitudes toward risk of owners and management

The management attitudes that most directly influence the choice of financing are those concerning (1) control of the enterprise and (2) risk. Large corporations whose stock is widely owned may choose additional sales of common stock because they will have little influence on the control of the company. In contrast, the owners of small firms may prefer to avoid issuing common stock in order to be assured of continued control. Because they generally have confidence in the prospects of their companies, and because they can see the large potential gains to themselves resulting from leverage, managers of such firms are often willing to incur high debt ratios.

(6) lender attitudes toward firm and industry

Regardless of management's analysis of the proper leverage factor for their firms, lenders' attitudes are frequently the most important determinant of financial structure. When management [illegible] to use leverage beyond norms for the industry, lenders may be unwilling to accept such debt increases. They will emphasize that excessive debt reduces the credit standing of the borrower and the credit rating of the securities previously issued.

Traditionally, corporations have had three sources of capital for investment in property, plant and equipment:

(1) Reserves for depreciation, depletion and amortization are essentially deductions from operating income which can be used for new investment.
(2) Long-term and short-term debt may be increased through the sale of debentures and other debt instruments.
(3) Equity capital may be raised through the issuance of preferred or common stock.

With regard to reserves, they are generally short-term and, in many cases, not sufficient in amount. Both long- and short-term debt are constrained by the lending institutions' desired capitalization profile for a firm. For example, long-term debt for utility companies is typically on the order of 45-55 and debt greater than 55 could lead to a lowering of bond ratings. In many cases there are mortgage indenture coverage requirements in times-interest-earned before new debentures can be issued. For equity capital, preferred stock typically represents 10-15 of total capitalization and common stock 30-40 for utility companies. There are in many cases coverage requirements on both interest and dividends before new equity capital can be raised.

This discussion points out that, even though it may be technically feasible for a company to convert from using oil and/or gas to the use of coal as its primary fuel, the financial impact of the firm must be considered as well as the sources of the needed capital. The ability to attract capital is promoted by a demonstrated ability to provide investors with a fair and reasonable return on their investment, to maintain a balanced capitalization structure, and to generate a reasonable amount of capital requirements internally.

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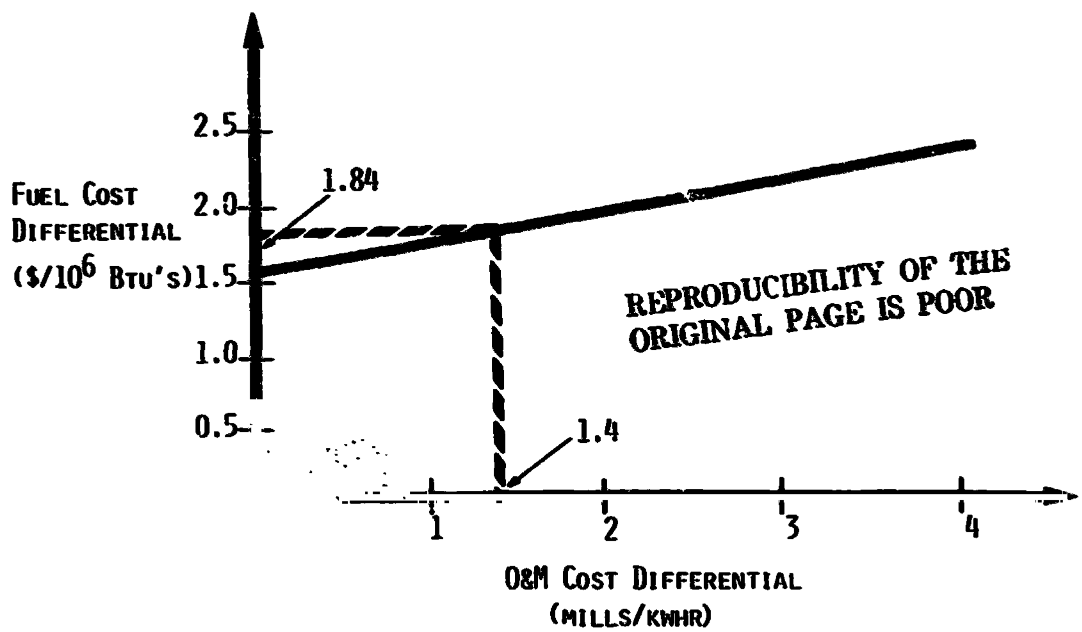

Fig. 1. Fuel Cost Differential Versus O&M Cost Differential for Breakeven

Table 1. Illustrative Site Characteristics and Fuel Prices

SITE CHARACTERISTICS

Boiler Unit	Megawatt Capacity	Remaining Life	Operating Capacity Before	Operating Capacity After	Derating Percent
Number 1	51.0	20	.550	.550	0.000
Number 2	107.0	20	.550	.550	0.000

FUEL PRICES (IN DOLLARS PER MILLION BTU'S)

	Before Conversion	After Conversion
Coal	0.0000	1.6000
Oil	1.9130	
Natural Gas	1.5500	

Table 2. Illustrative Cost Data

INVESTMENT COST DATA

NON AIR POLLUTION CONTROL EQUIPMENT INVESTMENT COST	6668000.
AIR POLLUTION CONTROL EQUIPMENT INVESTMENT COST	8852000.
TOTAL INVESTMENT COST	15520000.
TOTAL INVESTMENT COST PER KILOWATT	98.23

AMORTIZATION PERIOD DATA

TIME TO COMPLETE CONVERSION IN YEARS	5
AVERAGE REMAINING USEFUL LIFE IN YEARS	20
INVESTMENT AMORTIZATION PERIOD IN YEARS	15

ANNUAL COST DATA

NON AIR POLLUTION CONTROL EQUIPMENT ANNUAL OPERATION AND MAINTENANCE COST DIFFERENTIAL	256000.
AIR POLLUTION CONTROL EQUIPMENT ANNUAL OPERATION AND MAINTENANCE COST DIFFERENTIAL	576000.
AMORTIZED TOTAL INVESTMENT COST	0.
ANNUAL FIXED CHARGE COST	4247574.
ANNUAL FUEL COST DIFFERENTIAL	-2416297.
TOTAL ANNUAL COST DIFFERENTIAL	2643077.
TOTAL OPERATION AND MAINTENANCE COST DIFFERENTIAL PER KWHR	.0011

Table 3. Illustrative Fuel Consumption Data and Values of Coal Conversion Measures

FUEL CONSUMPTION DATA

AVERAGE ANNUAL OIL CONSUMPTION IN BARRELS BEFORE CONVERSION	1254065.
AVERAGE ANNUAL NATURAL GAS CONSUMPTION IN MCF BEFORE CONVERSION	629457.
AVERAGE ANNUAL COAL CONSUMPTION IN TONS BEFORE CONVERSION	0.
AVERAGE ANNUAL BTUS BEFORE CONVERSION (IN MILLION-MILLIONS)	8.4498
AVERAGE ANNUAL BTUS AFTER CONVERSION (IN MILLION-MILLIONS)	8.4498
AVERAGE ANNUAL COAL CONSUMPTION IN TONS AFTER CONVERSION	552075.
EQUIVALENT ANNUAL BARRELS OF OIL SAVED AS A RESULT OF CONVERSION	1355005.

COAL CONVERSION MEASURES

ANNUAL COST PER EQUIVALENT BARREL OF OIL SAVED	1.95
CHANGE IN COST PER KILOWATT-HOUR OF ELECTRICITY GENERATED	.003472
INTERNAL RATE OF RETURN ON COAL CONVERSION INVESTMENT(PERCENT)	6.061
AFTER TAXES RATE OF RETURN ON COAL CONVERSION INVESTMENT(PERCENT)	3.209