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PRESENT AND FUTURE COMBUSTION SYSTEMS

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by

F. D. Friedrich*

ABSTRACT

It is pointed out that, in the future, industry will have to strive for high efficiency in energy utilization and will have to reduce its dependence on natural gas and petroleum in favour of coal. Some gains in fuel conservation can be achieved by utilizing combustion aerodynamics to match flame characteristics with process requirements. Other significant gains can be made through combined processes, such as topping process-steam production with electricity generation.

Fluidized-bed combustion is believed likely to emerge soon as a major new technological development because of its ability to burn low-grade fuels with minimum pollutant emissions. Its advantages and state of development are briefly described. Combustion of coal-in-oil slurry is described as a means for reducing oil consumption in existing oil-fired equipment.

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1. INTRODUCTION

Historically, fossil fuels have been the diet on which industry has been nourished. It was no accident that the first nations to achieve industrialization were those which recognized their indigenous fuel resources and developed the technology to utilize them. As more efficient means of bulk transport were developed, it became possible for nations without indigenous fuel resources to industrialize, provided they enjoyed other advantages such as raw materials or cheap labour. Now, however, as the finite limits of the world's fossil fuel resources become increasingly apparent, the vulnerability of industry to disruption in fuel supply has become a matter of considerable concern.

Canada is fortunate to have substantial fuel resources; enough to maintain industrial health for many decades to come. At present Canadian industry is heavily dependent on petroleum and natural gas, whereas our most abundant fossil fuel is coal. With the present state of the art as a background, this paper explores both the probable changes in combustion technology by which gas and petroleum resources can be conserved and the increased utilization of coal with a minimum of disruption.

2. RELATIVE USE OF FOSSIL FUELS IN MARKET SECTORS

As a preliminary to outlining present practice and probable trends in industrial combustion systems, it is helpful to review briefly the relative usage of the major fossil fuels in each of the market sectors. A generalized comparison appears in Table 1. Light oil is considered to be diesel oil, No. 1 fuel oil, and No. 2 fuel oil. Heavy oil is defined as fuel oil grade No. 3 through 6, but the overwhelming bulk of heavy oil in use consists of No. 6, which is also known as Bunker C or residual fuel oil. The term coal is meant to include the full range of solid fossil fuels; lignite, sub-bituminous, bituminous, and anthracite.

The domestic market is considered to include space heating and water heating for single family dwellings having individual furnaces. The commercial market includes apartment buildings, business blocks and commercial buildings where fuel is used primarily for space heating purposes. The industrial market, on the other hand, comprises that sector which uses fuel primarily for purposes other than space heating. It accordingly covers a very wide spectrum of applications, such as laundries, food processing, paper-making, cement manufacturing, and metal refining. Finally, the electric utility market uses fuel for large-scale generation of electricity.

The foregoing definitions of market sectors are somewhat arbitrary and there are, admittedly, areas of overlap, but they serve to delineate typical system capacity ranges and fuel applications. The transportation sector is considered to be outside the scope of this discussion because it appears that it will be totally dependent on refined oil for some time to come.

TABLE 1

Relative Use of Fossil Fuels in Market Sectors

Market Sector	Domestic	Commercial	Industrial	Electric Utility
System Capacity, Millions of Btu/hr	0-0.2	0.2-20	20-500	500-5000
Fuels				
Natural Gas	extensive	extensive	extensive	limited
Light Oil	extensive	extensive	limited	limited
Heavy Oil	none	limited	extensive	extensive
Coal	very limited	very limited	extensive	extensive

3. DEFINITIONS OF EFFICIENCY

It is inevitable in any discussion of combustion systems that reference be made to efficiency, doubtless the most misused term in the engineering vocabulary. In this paper, the following definitions will apply.

3.1 Combustion Efficiency

This is simply the percentage of input fuel energy which is converted to heat, i.e., burned, in a combustion system. To put it another way, combustion efficiency equals 100% minus the percentage of input energy in the unburned fuel leaving the system. Figure 1 illustrates this concept by means of a simple Sankey diagram. Any unburned fuel in the flue gas is likely to consist of gaseous or vapourized hydrocarbons, carbon monoxide and elemental carbon. The combustion efficiency of modern systems is generally very high. Typically, the unburned fuel loss is negligible when burning natural gas, about 0.10% and seldom more than 0.25% when burning oil. With coal-fired systems, the presence of ash tends to inhibit combustion of fixed carbon, giving rise to a larger loss of 5% or less which is typical for a medium-ash coal.

3.2 Combustion System Efficiency

Combustion system efficiency is defined as the percentage of input fuel energy which is converted to useful heat. In order to define the fraction of useful heat, it is first necessary to define the system. Figure 2 gives two examples, the first being a conventional boiler, the second being a combustion system whose function is to produce a mixture of hot air and flue gas for a drying application.

In computing combustion system efficiency, some unavoidable losses become apparent, such as those due to moisture and hydrogen in the fuel.

3.3 Process Efficiency

The thermal efficiency of a process is the percentage of input fuel energy which appears in the final product. Again, this requires definition of the process envelope. Figure 3 gives two examples, the first being the common case of thermal electricity generation, the second being the chemical process of cement manufacture.

3.4 Burner Mixing Efficiency

For a discussion of burner performance, it is useful to define yet another efficiency term, burner mixing efficiency. Depending upon the application, a burner may have to fulfil several functions. Basically, it must mix the fuel and air, provide for stable ignition of the mixture and ensure acceptably complete combustion of the fuel. The burner may also be required to shape the flame to suit the combustion chamber or process and provide combustion conditions which minimize the formation of certain pollutants. Finally, the burner is usually expected to contribute substantially to optimizing the combustion system efficiency.

The means which a burner has to fulfil its functions are control of fuel-air mixing and, to a limited extent, the application of refractory to control heat input to the fuel-air mixture. However, the use of these is constrained by the conflicting nature of the burner's functions. For example, acceptably complete combustion of the fuel can generally be achieved by providing an excess of combustion air but this increases the dry flue gas loss, thus impairing system efficiency. Stable ignition and good burn-out can also be achieved by using refractory combustion chambers, but this raises flame temperature and is likely to increase the formation of nitrogen oxides. In general, a burner can best fulfil its functions if its mixing capabilities are such that it can operate with as little combustion air as possible.

In this context, burner mixing efficiency can be defined as the ratio of the air theoretically required for complete combustion to the air actually required for reasonably complete combustion, expressed as a percentage. In more conventional terminology;

$$\text{Burner mixing efficiency} = \frac{\text{stoichiometric air}}{\text{stoichiometric air + excess air}} \times 100$$

The functions of a burner and the definition of burner mixing efficiency are summarized in Table 2.

TABLE 2

Burner Functions and Parameters

Burner Functions:

1. Mix fuel and air.
2. Provide stable ignition.
3. Provide acceptably complete combustion of the fuel.
4. Shape the flame to suit the combustion chamber or process.
5. Minimize pollutant formation.
6. Maximize or optimize combustion system efficiency.

Means for accomplishing the foregoing:

1. Control of fuel-air mixing.
2. Control of heat input to mixture via refractory.

Definition:

$$\text{Burner mixing efficiency} = \frac{\text{theoretical air requirement}}{\text{air required for reasonably complete combustion}} \times 100$$

$$= \frac{\text{stoichiometric air}}{\text{stoichiometric air + excess air}} \times 100$$

4. PRESENT INDUSTRIAL COMBUSTION EQUIPMENT

4.1 Natural Gas Burners

Typically, industrial natural-gas-fired equipment employs turbulent-flame power burners. That is to say, a forced-draft fan supplies combustion air at a pressure of a few inches water column and the pressure drop across the burner register creates turbulence to mix the fuel and air. The register, besides controlling the flow of combustion air, may also impart a swirling motion to increase turbulence, thereby improving mixing. Air and fuel are usually introduced coaxially with the gas being fed through multiple ports arranged either in the centre of, or around, the air stream. Figure 4 shows a conventional gas burner with the former arrangement. Ignition is stabilized 1) by a diffuser near the gas ports which creates a localized area of low velocity and 2) by a refractory throat which reaches incandescent temperatures during operation.

Industrial burners of this nature have been developed to a high degree of sophistication in terms of automatic operation, modulating control and safety features. Since mixing in the gas phase is relatively easy to accomplish, these burners readily achieve mixing efficiencies of 90% to 95%.

4.2 Oil Burners

Modern oil burners, like those for natural gas, generally use a forced-draft fan to produce turbulent mixing. Indeed, the hardware may be interchangeable. Provided the pumpset, heaters, piping and control train are at hand, converting from natural gas to oil firing may be simply a matter of inserting an oil gun down the centre of the gas pipe, as shown in Figure 4. To permit intimate fuel-air mixing, the oil is ejected as a spray of tiny droplets. This may be accomplished by using high pressure to force the oil through an atomizing nozzle, or the expansive force of steam or compressed air may be used. Steam atomizing is widely used because it provides good control of droplet size and, therefore, high mixing efficiency over a wide range of firing rates for any given nozzle size. The same burners may be used for any grade of fuel oil, the main differences being that light oils require closer pump tolerances whereas heavy oils require preheating.

Residual oils contain ash which may cause corrosion or slagging of heat transfer surfaces. Therefore, it is particularly important that flames do not impinge on any water-cooled surfaces and that tube-metal temperatures be kept below the ash-melting temperature of approximately 650°C. While this can be accomplished through appropriate combustion chamber geometry, substantial economies can be achieved if the burner has some ability to shape the flame. To do this, many burners employ fairly sophisticated aerodynamics; for example, combustion air may be supplied in two coaxial streams with separate swirl control on each, as shown in Figure 5. The burner shown is also capable of burning natural gas; in this case the gas nozzles are located around the combustion air stream. Some recent burner designs utilize partial precombustion chambers to improve mixing and flame stability.

In general, oil burners have achieved the same level of automation and safety as gas burners. In medium to large industrial applications, mixing efficiency may be 90% to 95% at full-firing rate, but is likely to be about 70% at one third of full-firing rate.

4.3 Coal-Fired Equipment

4.3.1 General

Most industrial systems presently burning coal employ pulverized firing or some variation of it. The coal stoker-grate systems which enjoyed a substantial share of the market twenty years ago have, for the most part, been replaced by oil- and gas-fired equipment. Because of 1) high capital, labour and maintenance costs, 2) sensitivity to coal properties, 3) somewhat inferior efficiency and 4) pollution problems, a significant trend back to stoker technology is not expected by this writer.

Pulverized firing, on the other hand, has proven itself to be efficient and reliable. Burner mixing efficiencies are typically 85% or higher. Because the capital and operating costs are high, pulverized firing is only economic at this time for large systems, e.g. boilers producing 250,000 lb of steam/hr or more. In addition, it is sensitive to a variety of coal properties. Generally plants are designed for a particular type of coal and the scope for substitution is limited.

Three main types of pulverized-fired combustion systems for coal are dry-bottom firing, slag-tap firing and cyclone firing. These are described briefly in the following sections.

4.3.2 Dry-Bottom Furnaces

In dry-bottom systems, the coal is pulverized to about 80% through a 200-mesh screen (80% of particles are less than 74 μ diam) and then pneumatically injected into a large water-cooled furnace such as is shown in Figure 6. The spray of coal particles burns much like a spray of oil droplets and high flame temperatures are achieved. Most of the ash particles melt and must be cooled back down to the solid state before they impinge on any heating surfaces; otherwise slag deposits build up, reducing heat transfer and blocking gas passages. It follows that the lower the ash-softening temperature, the larger the radiant section of the furnace must be to provide the necessary residence time and heat sink for cooling. Generally, about 20% to 40% of the ash settles out in the furnace and boiler hoppers; the rest is entrained in the flue gas stream and must be removed by dust collection equipment such as electrostatic precipitators.

Some pulverized-coal burners are similar in configuration to oil burners, having a central pipe carrying the coal dust and the primary air which transports it, surrounded by a coaxial stream of secondary air. Other burners consist of a vertical array of rectangular nozzles, with nozzles carrying coal and primary air sandwiched between nozzles carrying secondary air, as shown in Figure 7. Burners are generally arranged in banks on one wall of the furnace, on opposite walls or in each corner. Burners firing downward from the furnace roof are common in some European countries, but are not widely used in North America.

4.3.3 Slag-Tap Furnaces

Slag-tap furnaces are designed to maintain sufficiently high temperatures that most of the ash can be tapped from the furnace as slag. Generally,60% to 80% of the ash is removed in this fashion. The remainder is entrained in the flue gas and a radiant-cooling section must be provided to drop the flue-gas temperature below the ash softening temperature before it impinges on heat-transfer surfaces. Where high-ash coals having a low-ash softening temperature must be burned, slag-tap firing may permit the use of a somewhat smaller furnace and will substantially reduce the size of electrostatic precipitator required.

Slag-tap firing is not as widely used in North America as in Europe, but one furnace design which has achieved acceptance here is shown in Figure 8. It employs burners on opposite walls of the furnace, inclined downward so the flames impinge over the tap hole. The molten ash runs out of the tap hole into a quenching tank filled with water.

4.3.4 Cyclone Furnaces

Like the slag-tap furnace, the cyclone furnace is designed to remove the ash in a molten state. It differs in that it separates the conflicting functions of maintaining sufficient temperature to melt the ash, and the subsequent cooling of the gas stream below the ash-softening temperature. Furthermore, the cyclone burns crushed, rather than pulverized, coal and does not burn it in suspension.

Figure 9 illustrates the cyclone principle. Coal crushed to - 1/8 in.is transported into a large refractory-lined cylinder into which a high-velocity stream of air is introduced tangentially. Very intense combustion occurs, producing high temperatures which result in a layer of molten ash forming on the inside walls. The incoming coal particles are trapped in the slag layer and burn as the air sweeps past. The combustor has a re-entrant throat so that only fine ash particles escape with the gas stream. The slag drains through tap holes below the throat.

From the combustor the flue gases pass into a radiant furnace, as shown in Figure 10, where entrained ash particles are cooled below their softening temperature. The gases then flow through the usual banks of convective heat-transfer surface to the gas-cleaning equipment and the stack. Cyclone combustors can operate successfully with coals having an ash-softening temperature of 2600°F, but turn-down is improved with lower ash softening temperatures.

5. ANTICIPATED TRENDS IN INDUSTRIAL COMBUSTION SYSTEMS

5.1 Fuel Availability and Environmental Constraints

It now seems clear that in the future, the selection of fuels for industrial applications will be governed more by availability than by cost of fuel, combustion equipment, or labour. Our diminishing resources of natural gas and refined oil will have to be progressively reserved for the domestic heating market which has little in the way of alternatives. Industry will then have to utilize increasingly low-grade fuels. Residual oil will probably continue to be available for some time, although quantities may be limited. Some process heat may be generated by nuclear sources. The use of combustible refuse such as wood waste, municipal garbage and industrial waste is likely to increase. However, unless production of pipeline-quality gas from coal is undertaken on a massive scale, the industrial sector will probably be burning large quantities of raw coal by the end of this century. It should be noted also that the Canadian coals least expensive to mine are those of low quality.

Superimposed on the expected trend to low-grade fuels will probably be increasingly stringent environmental constraints. Emission regulations will doubtless be rationalized as we improve our knowledge of the real effects of pollutants but hopefully the days of uncontrolled emissions of sulphur oxides, particulates and heavy metals, are gone forever, even though industrial fuel quality deteriorates.

5.2 Improvements in Burner Technology

The increasing cost of conventional fuels provides a strong incentive to conserve our resources by developing more efficient burners. It has been pointed out that present industrial burners for oil and natural gas typically have a mixing efficiency of 90% to 95%, while those for coal have a mixing efficiency of 85% to 90%. Thus, even if the control problems and explosions hazards of stoichiometric combustion are overcome, the gain in terms of fuel conservation is modest.

Nonetheless, in many industries there is substantial scope for improvement in process efficiency. Figure 11 illustrates this for some major industries, based on US data. Undoubtedly, improved burner technology can make substantial advances toward the goal of theoretical minimum energy consumption, but this will be more by means of improved heat transfer from flames than by stoichiometric combustion. That is to say, as the science of combustion advances, it will be possible to tailor flames more precisely to particular process requirements. Some examples are: short, bushy, luminous flames for steam-raising; long, slender flames for cement kilns; high radiant heat transfer rates for billet reheating furnaces. Much of the theoretical background necessary for controlling flame shape and heat transfer characteristics is already at hand due to the efforts of many research agencies, notably the International Flame Research Foundation in Holland. Still, considerable effort is required to transfer this knowledge to industrial practice.

One of the most powerful methods for controlling flame characteristics by aerodynamic means is the application of swirl, i.e., a tangential velocity component, or spin, to the combustion air. This creates a radial pressure gradient which causes the air, when it leaves the confines of the burner quarl, to move outward leaving a zone of low pressure in the centre. The low-pressure zone, in turn, permits a central reverse flow to develop, as shown in Figure 12, which consists essentially of very hot combustion products and some unburned fuel. The results are a powerful enhancement of flame stability and sharply improved fuel-air mixing.

By adroit design, swirl can be used to control flame shape, burner mixing efficiency, local heat release pattern and even, to some extent, pollutant formation. Figure 13 gives some examples of different configurations and the resulting velocity distribution at various downstream distances. View A shows a conventional burner having weakly swirled combustion air and flame stabilization by means of a diffuser. The flame is long and narrow with relatively slow fuel-air mixing. The flame is stabilized by eddies in the wake of the diffuser, but tends to lift off if air velocity is increased. View B shows a burner with no diffuser but strongly swirled combustion air which sets up a strong recirculating vortex at the point of fuel injection. This effectively stabilizes the flame and creates high turbulence which improves fuel-air mixing. The flame is shorter and much wider. View C shows a burner with a small, strongly-swirled stream of primary air and a concentric, high-velocity stream of unswirled secondary air. The swirling stream of primary air creates a small zone of recirculation which stabilizes ignition but this is overpowered a short distance downstream by the high-velocity secondary air jet. The fuel stream does not have sufficient energy to escape through the secondary air jet but mixing is relatively slow, resulting in a long, narrow flame suitable for a cement kiln, for example. View D shows a burner having primary- and secondary-air streams, both strongly swirled, firing into a small combustion chamber connected to a large furnace. This results in very high rates of combustion in the annulus next to the combustion chamber walls, very short flame and a large reverse-flow zone which recirculates substantial quantities of downstream flue gas into the combustion zone. Besides being capable of near-stoichiometric operation, such a burner produces low levels of nitrogen oxides, presumably because the flame temperature is reduced by the large-scale dilution with downstream flue gas.

Another way in which improved burner technology may contribute to energy resource conservation is through the development of coal-in-oil firing. Pilot-scale research at the Canadian Combustion Research Laboratory[1/] has demonstrated that, with some changes in burner hardware, a slurry of up to 33% pulverized coal in fuel oil can be burned in conventional oil-fired boilers. This means that, in cases where environmental constraints on particulate emissions can be met, existing oil-fired installations can reduce their oil consumption by one third, making up the difference with coal.

The pilot-scale work on coal-in-oil slurries has attracted the attention of one major US industry to date. In August 1974 this firm successfully completed a one-week combustion test with 35% coal in No. 2 oil, fired into a 30,000 lb/hr package boiler. A 2-month test, firing 35% coal in No. 6 oil into a 125,000 lb/hr boiler is expected to begin in March 1976.

5.3 New Combustion Systems

5.3.1 Fluidized-Bed Combustion

The fluidized-bed combustor appears to be the most promising development in new technology for the use of low-grade fuels. Its apparent advantages include economy of construction, high efficiency, low pollution emission, and insensitivity to fuel properties. Furthermore, it seems to be economically viable for small industrial applications as well as large ones.

Fluidized beds have been used in the chemical industry for many years in processes requiring contact between gases and solids. The principle is simple; a bed of granular material is supported in a vessel over a perforated plate and air, or some gas, is forced through the perforations at sufficient volume and pressure to support the weight of the bed. The bed material then behaves as a fluid; that is, it assumes a boiling action as it is continuously

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[1/] T. D. Brown and G. K. Lee "A Preliminary Study of the Combustion of Coal-in-Oil Slurries" Divisional Report FRC 72/40-CCRL, Energy Research Laboratories, CANMET, Department of Energy, Mines and Resources, Ottawa, Canada May 1972.

lifted and circulated by the bubbles of gas rising through it. This powerful stirring action makes the bed an excellent medium for transferring heat or bringing together chemical reactants. Two common applications are catalytic crackers in petroleum refining and production of sulphuric acid by roasting of sulphide ores.

The development of the fluidized-bed combustor began about ten years ago when it was recognized that, if a bed of inert refractory material were fluidized with air and preheated to the ignition temperature of coal, any coal subsequently introduced into the bed would burn, even though it comprised only a small fraction of the bed material. Furthermore, the coal would burn under conditions of intense mixing and relatively long residence times at a rate essentially controlled by the rate of coal feed. Two other advantages became apparent. First, heat transfer rates in a fluidized bed are very high. Therefore, the heat released by the burning coal particles is immediately absorbed by the inert bed material and in turn transferred to heat exchange surfaces, such as boiler tubes immersed in the bed. This permits combustion to occur at temperatures much lower than those in conventional flames, i.e. 800°C to 900°C instead of 1400°C to 1700°C, thus avoiding the problems associated with melting of coal ash components. The second advantage is that, if limestone or dolomite are added to the bed material, they will react with sulphur dioxide to form sulphates which remain in the bed, thus substantially reducing SO_2 emissions to the atmosphere.

To date over 20,000 hr of operating experience have been gained on pilot-scale fluidized-bed combustors built and operated by many different research agencies. Most of the work has been carried out in Great Britain and the U.S.A. where it has been related to the combustion of coal, but liquid and gaseous fuels as well as solid wastes such as garbage, wood chips and sewage sludge have also been burned. Combustion parameters, heat exchange rates, potential for pollution reduction and possibilities for power-generating cycles of improved efficiency, based on pressurized fluidized beds, have all been explored and the favourable conclusions have given impetus to development of industrial-scale equipment.

Probably the first prototype boiler utilizing a fluidized-bed combustor with in-bed heat extraction is shown in Figure 14. This is a vertical-tube shell boiler built as a test unit for the British Coal Utilization Research Association in 1969. It burns crushed coal in a bed 4 ft diam and about 2 ft deep. The boiler generates 8000 lb of steam/hr, with about half of the heat being picked up by the heat exchange surface immersed in the bed.

More recently, Babcock-Wilcox at Renfrew, Scotland, have converted a 44,000 lb/hr boiler, formerly stoker-fired, to fluidized-bed operation. The bed is 10 ft square and is equipped to operate with a wide variety of fuels. It went into service in June 1975 burning crushed coal and is being used for optimization studies of fuel feed and ash handling, bed size-distribution, fluidizing velocity, particle elutriation, start-up and shut-down procedures, control techniques, turn-down characteristics and other operating parameters. Experience with this equipment to date has confirmed the results of previous pilot-scale work. The combustion system is reported to be easy to operate and has burned coal with up to 50% ash.

As another important step toward commercialization of fluidized-bed combustors, the US Energy Research and Development Administration has sponsored the design and construction of a 300,000 lb of steam/hr boiler now being installed at the Rivesville Power Station in Fairmont, West Virginia. This unit has been designed as a prototype package boiler; outside dimensions are 12 ft wide, 25 ft high and 38 ft long. Thus, it illustrates the ability of fluidized-bed combustion to fire a coal-burning package boiler of greater capacity than is presently available with conventional oil or gas firing. The Rivesville boiler contains four separate beds which can be operated independently to improve turn-down. It is expected to go into operation in July 1976 and, at full capacity, will generate 30 MW of electricity.

It should be pointed out that a Canadian-based company has been marketing fluidized-bed combustion systems for the past few years and now has some dozens of units in operation, burning wood waste or industrial waste. None of them are burning coal, and none have in-bed heat recovery.

For large-scale steam generation, fluidized-bed combustors operating at several times atmospheric pressure seem to offer substantial economy in construction costs. Figure 15 shows the estimated size relative to present equipment.

The advantages and disadvantages of fluidized-bed combustion are summarized in Table 3. The body of literature on this subject is now substantial, but the proceedings of a recent international conference[1/] constitute an up-to-date summary of the state of the art.

5.3.2 Combined Heat-Power Processes

The changes in combustion equipment that will likely develop as industry resorts to lower-quality fuels have already been discussed. Aside from different burners and different fuels, the pressure for increased efficiency of fuel utilization is likely to bring about significant changes in the processes by which industry meets its requirements for heat and power. For example, smaller industries may find it economically advantageous to locate in industrial parks serviced with heat and process steam from a central plant which may be nuclear or coal-fired. In this way economies of scale,both in heat-raising and pollution control equipment,can be realized.

Conversely, large industries with a substantial requirement for process steam will likely find it increasingly attractive to generate their own electricity by means of back-pressure turbines. This has been a common practice in the pulp and paper industry, but in general the high capital cost of small-scale electric generation

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[1/] Proceedings of the Fourth International Conference on Fluidized-Bed Combustion, Washington, D.C., U.S.A. Dec 9-11, 1975. Available from the Mitre Corporation, Westgate Research Park, McLean, Virginia, U.S.A. 22101.

TABLE 3

Characteristics of Fluidized-Bed Combustion Systems

ADVANTAGES

1. Capable of burning solid, liquid or gaseous fuels.
2. Insensitive to fuel properties; can burn high-ash, high-moisture fuels.
3. Require little fuel preparation; e.g., can burn 1 in. x 0 coal.
4. Provide a long residence time for combustion.
5. Combustion occurs at low temperatures, minimizing NO_x formation and avoiding slagging problems with ash.
6. High rates of heat transfer to water tubes immersed in the bed.
7. Capital cost competitive with conventional equipment.
8. Can be operated economically in small as well as large unit sizes.
9. Can be operated with a bed material which neutralizes SO_2, eliminating the need for scrubbers.
10. Amenable to pressurized combustion, allowing compact equipment and substantial cost savings.
11. With pressurized combustion, a variety of more efficient power cycles becomes possible.

DISADVANTAGES

1. Require high combustion air pressure (20 in. to 60 in. WC).
2. Substantial elutriation, leading to high carbon loss and high dust loading in flue gas.
3. Difficult to achieve a wide turn-down range.

equipment has made it more economic for most industries to buy electricity from utilities whose economies of scale overcome the low process efficiency. Henceforth, however, the cost of electricity will be increasingly dominated by fuel cost, making process efficiency more important. Thus, every demand for process heat becomes an opportunity to generate electricity without the usual condenser loss and generating even a few megawatts is likely to become an attractive proposition.

Combining district heating with power generation has long been recognized as one way of improving the process efficiency of thermal-electric plants and the development of such systems is accelerating in many European countries. A common handicap in Canada is that thermal generating stations are often too large and too remote from population centres for an adequate district heating load to be found within economic heat-transport distances. Perhaps there is an opportunity here for industry. Where medium-sized industrial plants are operated in urban areas, it may be possible to combine the production of electricity and either process steam or high-temperature water for district heating in a fuel-efficient manner to the benefit of all concerned. The energy balance of such a combination is summarized in Figure 16.

6. SUMMARY

Industry presently depends mainly on natural gas, heavy oil and coal for its fuel needs. However, anticipated shortages of natural gas and petroleum will likely make it necessary to reserve them for transportation and domestic heating, forcing industry to strive for high efficiency of energy utilization and to rely more heavily on coal.

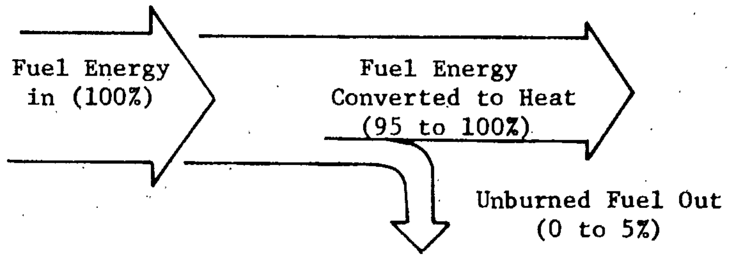
Present burners for fossil fuels, being fairly efficient, leave limited scope for improvement in combustion system efficiency. More substantial gains may be made in process efficiencies by more closely matching flame characteristics to process requirements. This can be achieved through more scientific application of combustion aerodynamics.

Fluidized-bed combustion is likely to emerge within the next decade as a major new technological development. It is well on the way to commercialization, and its main advantages are a) the ability to burn low-quality coal and waste products, b) economic viability for small- and medium-size installations as well as large ones, c) capability of minimizing NO_x and SO_x emissions, and d) suitability for more efficient, complex power cycles.

Industry is likely to make greater use of combined heat-power processes. Small industries may find it economic to buy process steam or heat from an electric utility. Large industries may find it economic to generate their own electrcity, using in place of condensers their process steam requirements and/or a district heating system.

COMBUSTION EFFICIENCY

$$\text{Combustion Efficiency} = \frac{\text{Fuel Energy Converted to Heat}}{\text{Fuel Energy Supplied}} \times 100$$



In modern systems combustion efficiency is high. (95 - 100%)

Unburned Fuel Out:	For natural gas; near	0
	For oil less than	0.25%
	For coal less than	5%

FIGURE 1: Sankey Diagram; Definition of Combustion Efficiency

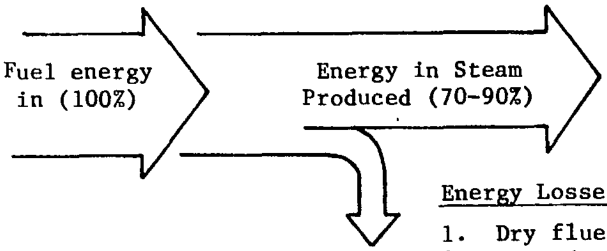
COMBUSTION SYSTEM EFFICIENCY

$$\text{CSE} = \frac{\text{Fuel energy converted to useful heat}}{\text{Fuel energy supplied}} \times 100$$

Must Define System

Example 1: Boiler Efficiency

$$\text{Boiler Efficiency} = \frac{\text{Energy in steam produced}}{\text{Fuel energy supplied}} \times 100$$

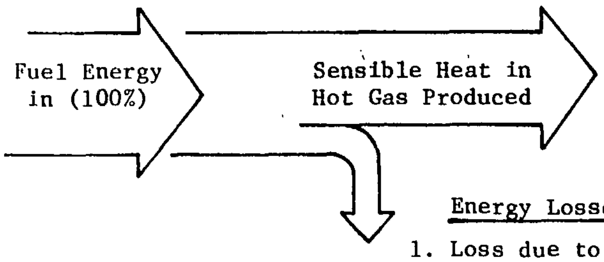


Energy Losses (10-30%)

1. Dry flue gas loss.
2. Loss due to moisture.
3. Loss due to hydrogen in fuel.
4. Loss due to unburned fuel.
5. Loss due to radiation and convection.
6. Other minor losses.

Example 2: Efficiency of a Direct-Fired Hot Air Generator

$$\text{Generator Efficiency} = \frac{\text{Sensible heat in hot gas produced}}{\text{Fuel energy supplied}} \times 100$$



Energy Losses

1. Loss due to latent heat in fuel moisture.
2. Loss due to latent heat in moisture from hydrogen in fuel.
3. Loss due to unburned fuel.
4. Loss due to radiation and convection.
5. Other minor losses.

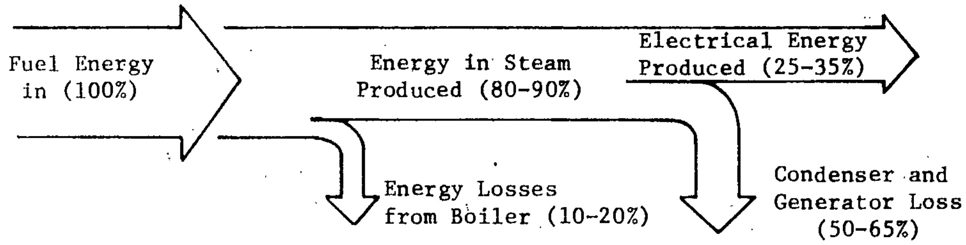
FIGURE 2: Sankey Diagrams; Definition of Combustion System Efficiency

PROCESS EFFICIENCY

$$\text{Process Efficiency} = \frac{\text{Theoretical energy required for or appearing in product}}{\text{Fuel energy supplied}} \times 100$$

Example 1: Electrical Generation Efficiency

$$\text{Process Efficiency} = \frac{\text{Electrical energy produced}}{\text{Fuel energy supplied}} \times 100$$



Example 2: Efficiency of Cement Making Process (Wet Process)

$$\text{Process Efficiency} = \frac{\text{Theoretical energy required for chemical reaction}}{\text{Fuel energy supplied}} \times 100$$

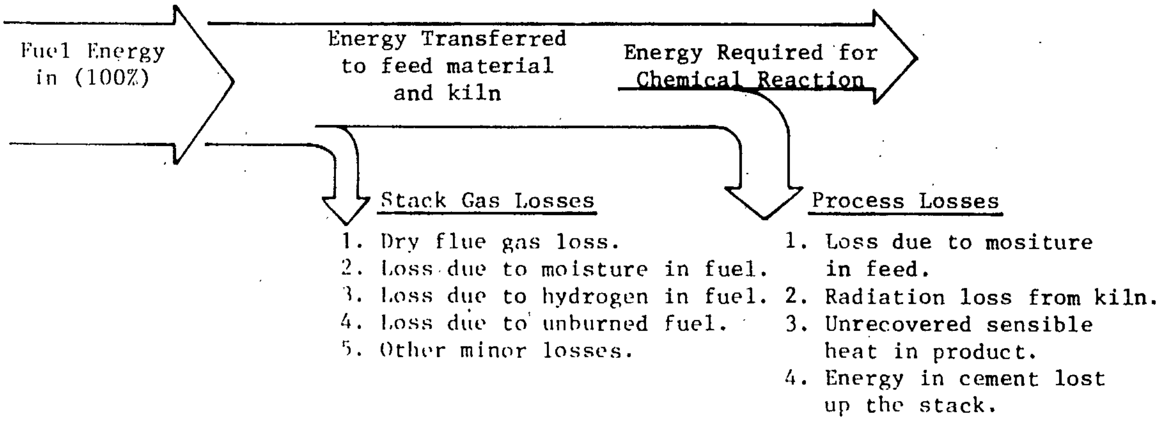


FIGURE 3: Sankey Diagrams; Definition of Process Efficiency

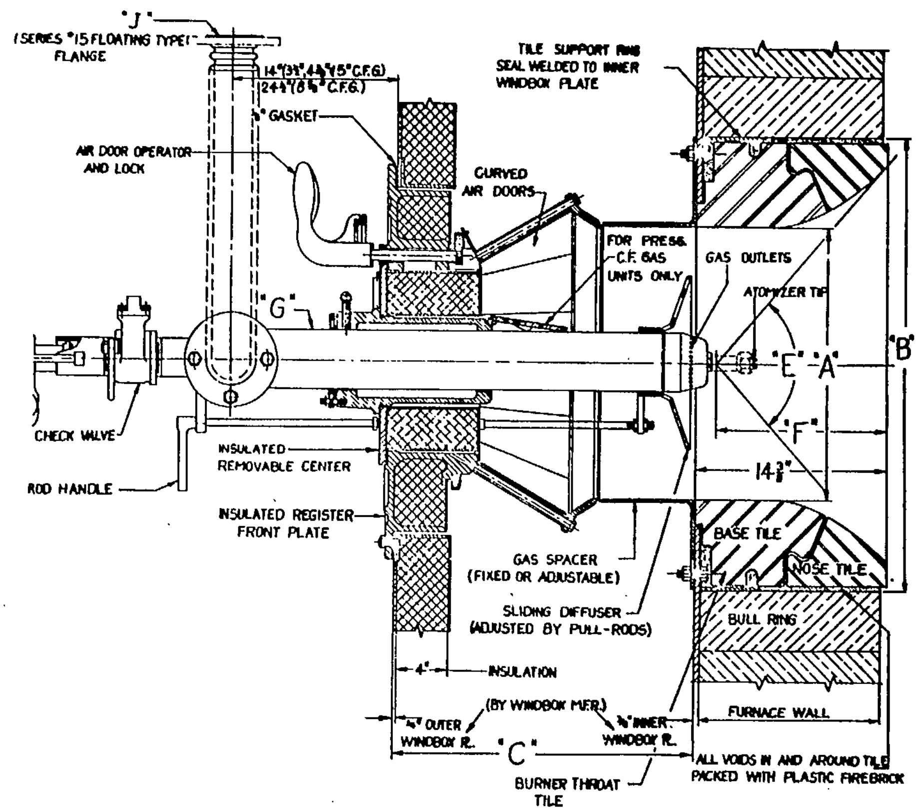


FIGURE 4: Sectional View of a Conventional Industrial Gas Burner

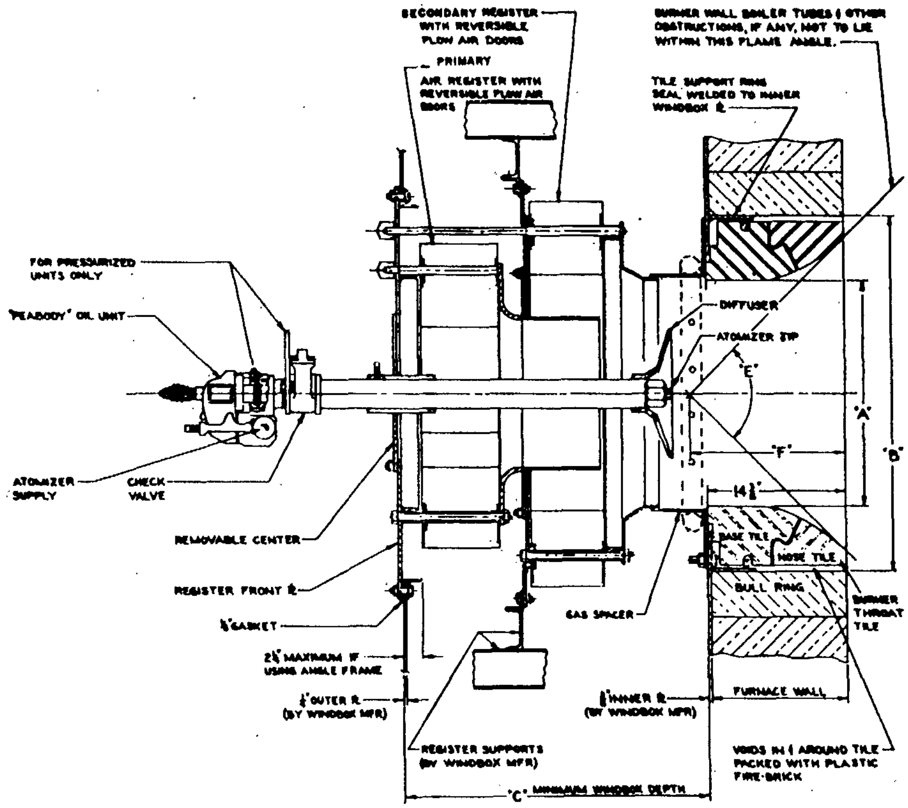


FIGURE 5: Sectional View of a Conventional Industrial Dual-Register Oil Burner

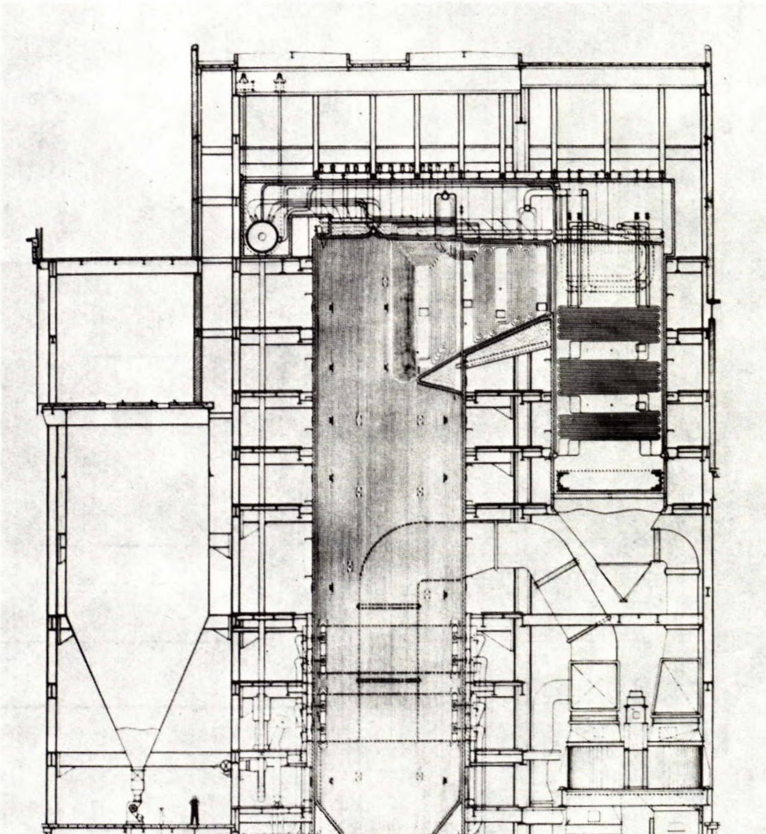


FIGURE 6: Sectional View of a Typical Dry-Bottom Boiler Burning Pulverized Coal

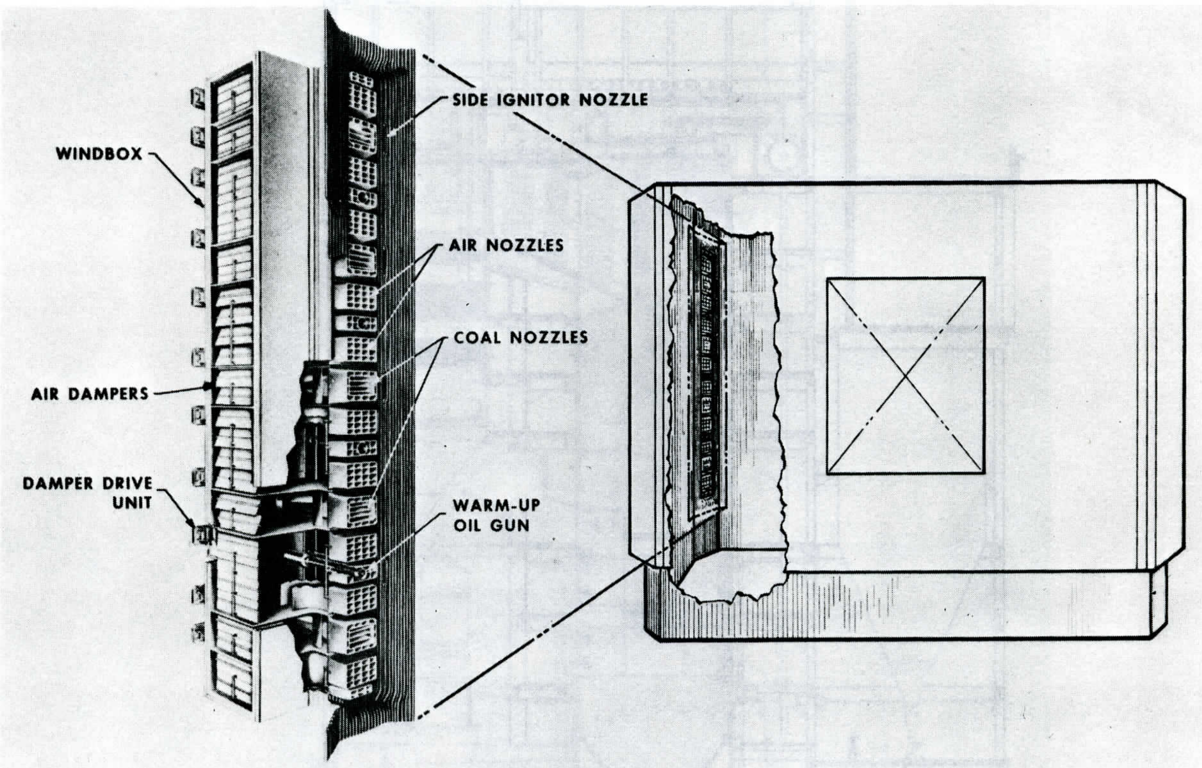


FIGURE 7: A Vertical-Array Burner for Pulverized Coal.
Courtesy of Combustion Engineering - Superheater, Ltd.

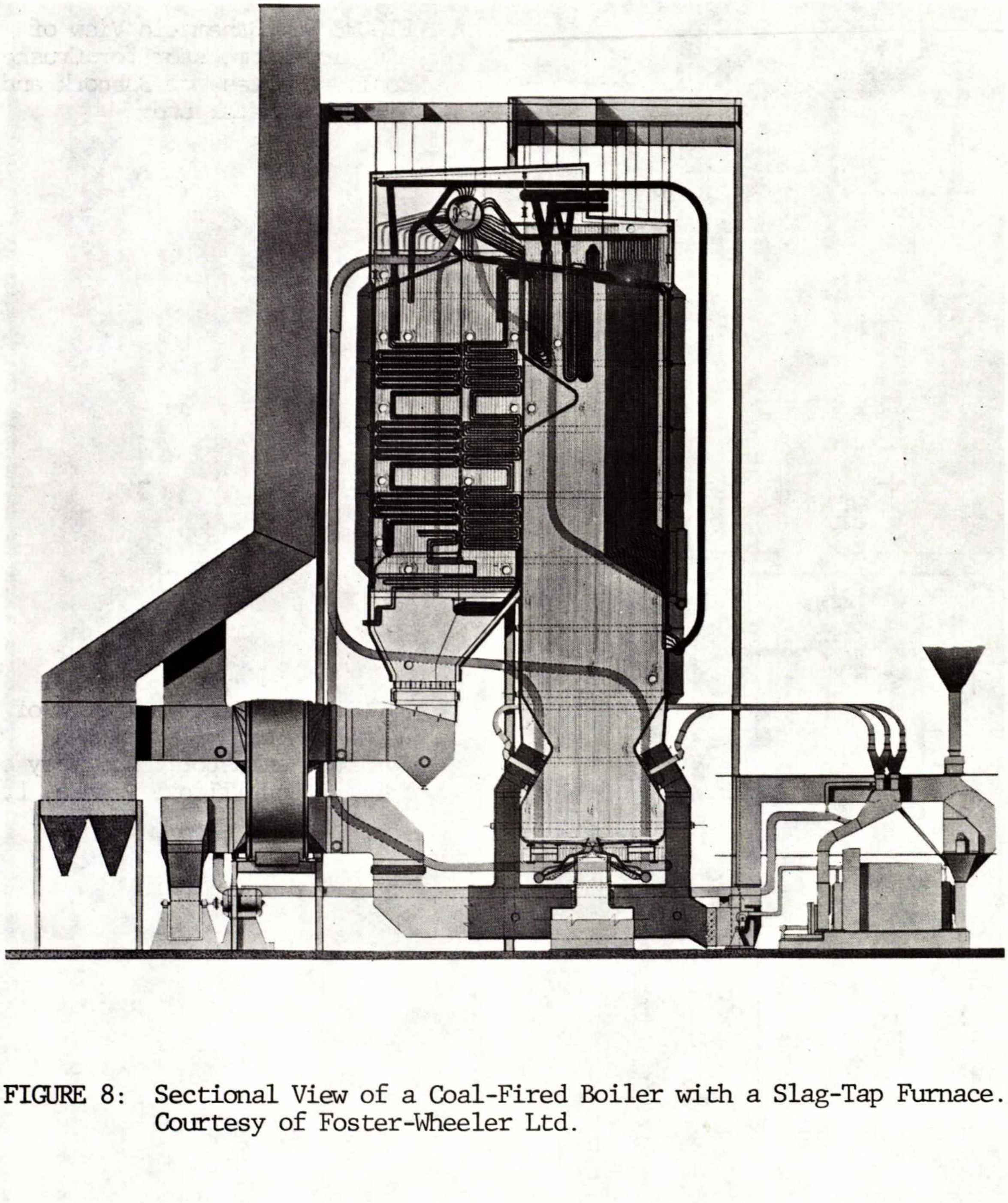


FIGURE 8: Sectional View of a Coal-Fired Boiler with a Slag-Tap Furnace. Courtesy of Foster-Wheeler Ltd.

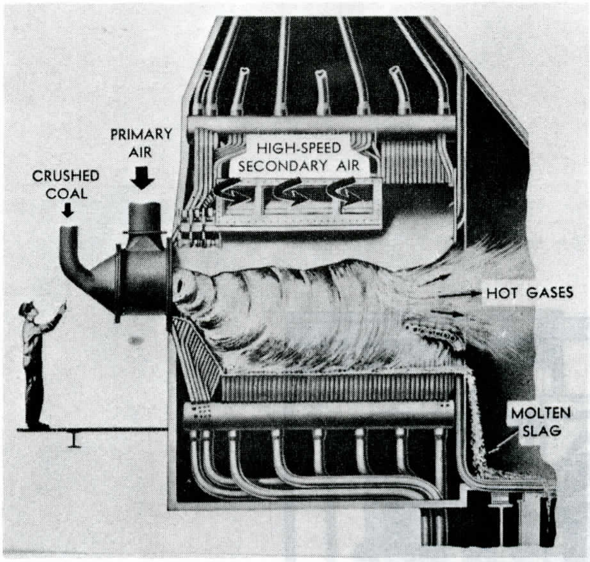


FIGURE 9: Schematic View of a Cyclone Combustor for Crushed Coal. Courtesy of Babcock and Wilcox, Canada, Ltd.

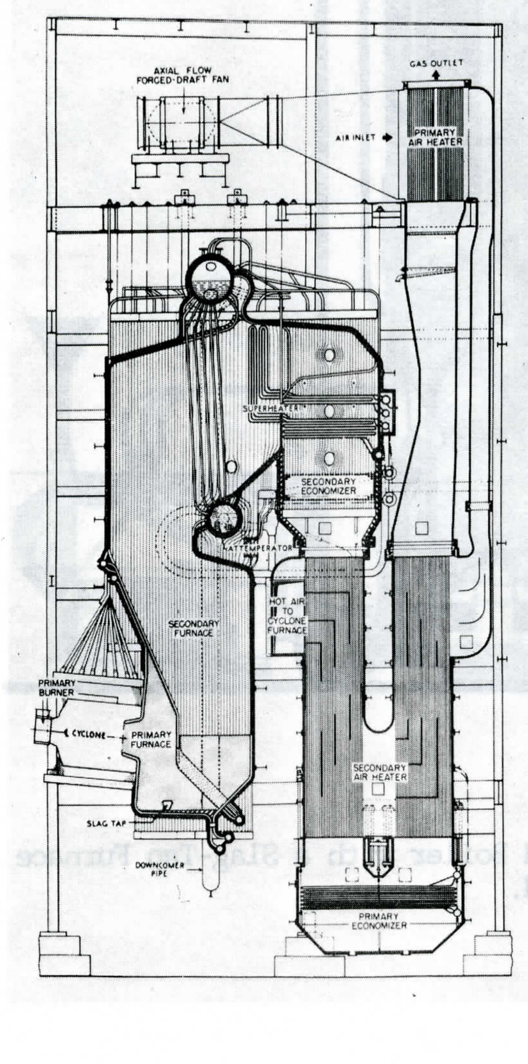


FIGURE 10: Sectional View of a Coal-Fired Boiler with a Cyclone Combustor. Courtesy of Babcock and Wilcox, Canada, Ltd.

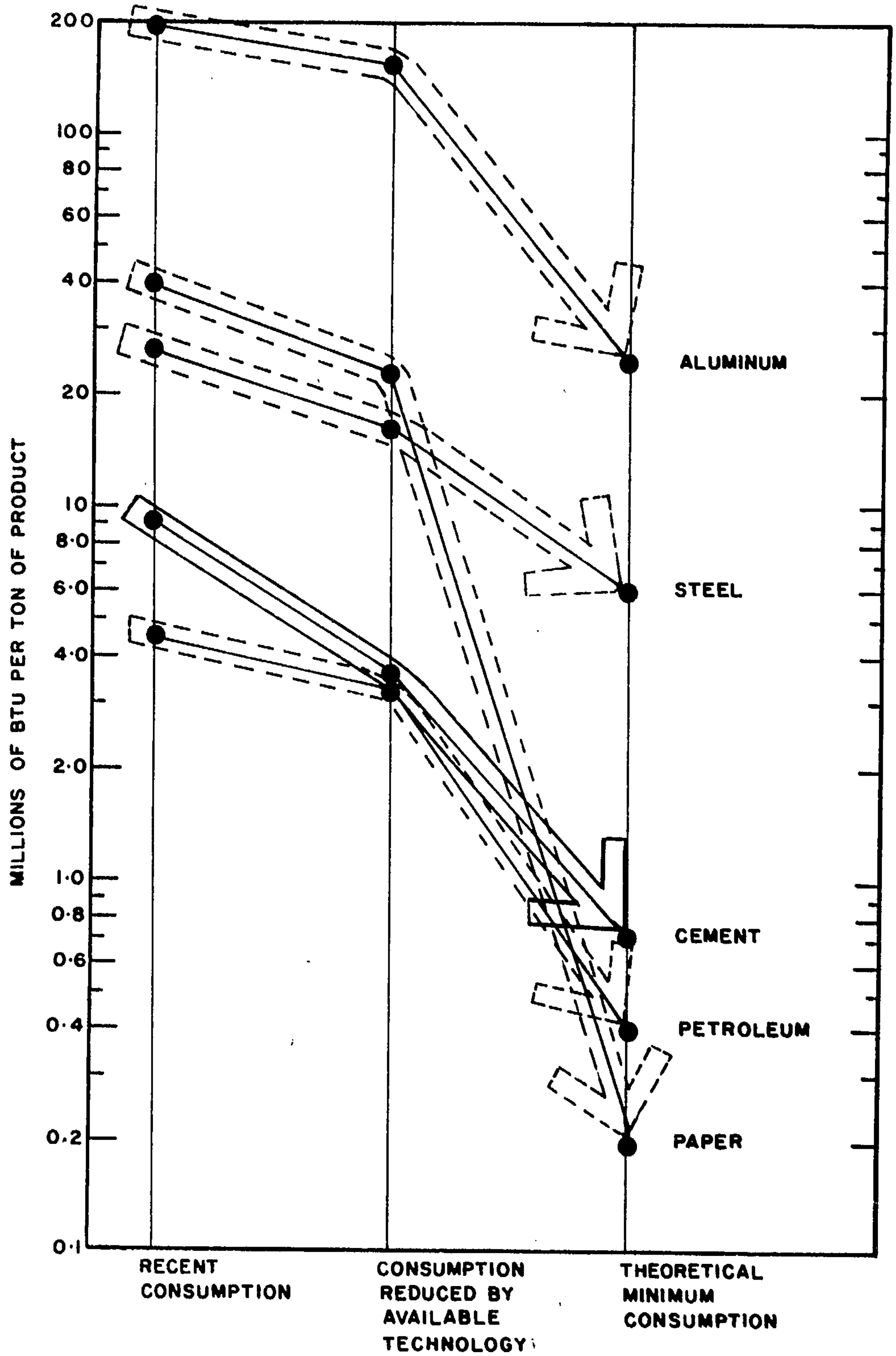


FIGURE 11: Actual and Theoretical Energy Requirements for Some Major Industrial Products. Taken from "The Far-Reaching Consequences of High-Priced Oil", by Sanford Rose, Fortune, March 1974.

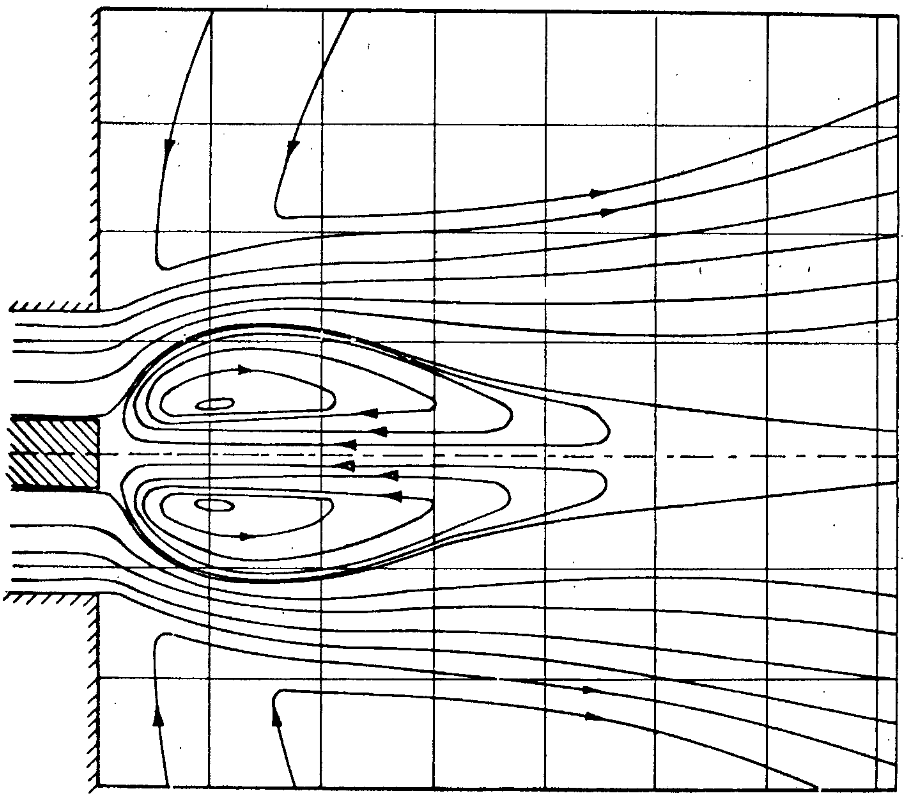
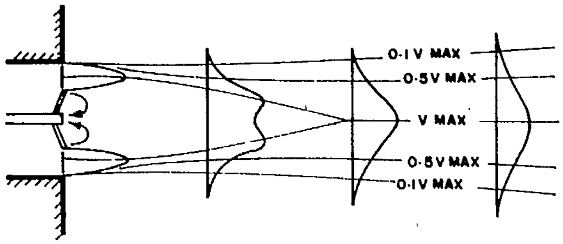
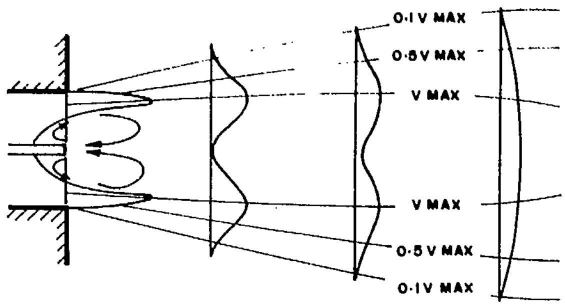


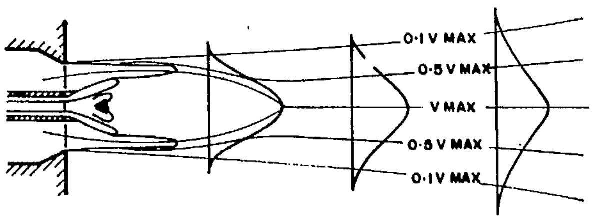
FIGURE 12: Typical Flow Streamline Pattern for a Burner with a Highly Swirled Air Supply



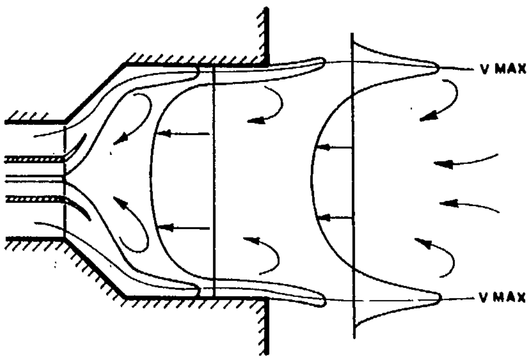
A Conventional burner with diffuser and low swirl.



B Burner with no diffusor and high swirl.



C Burner with a small flow of highly swirled primary air and high velocity, unswirled secondary air.



D Burner with highly swirled primary and secondary air, firing into a combustion chamber.

FIGURE 13: Effect of Swirled Combustion Air on Velocity Patterns

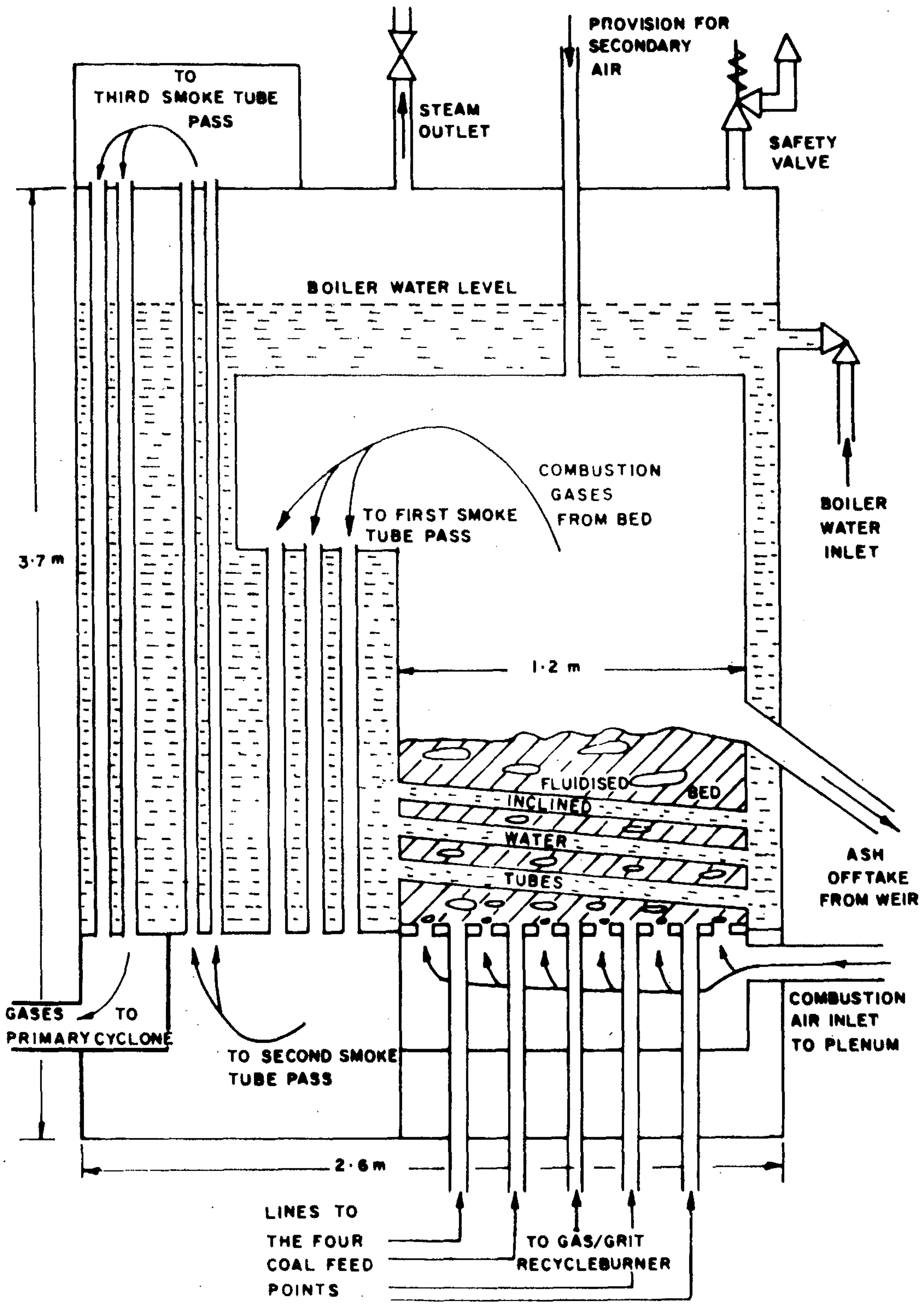


FIGURE 14: Diagram of a Small Vertical-Tube Shell Boiler Fired by Means of a Fluidized Bed.
Taken from "Fluidized Combustion for Western Fuels", by H.B. Locke and A. Orr.

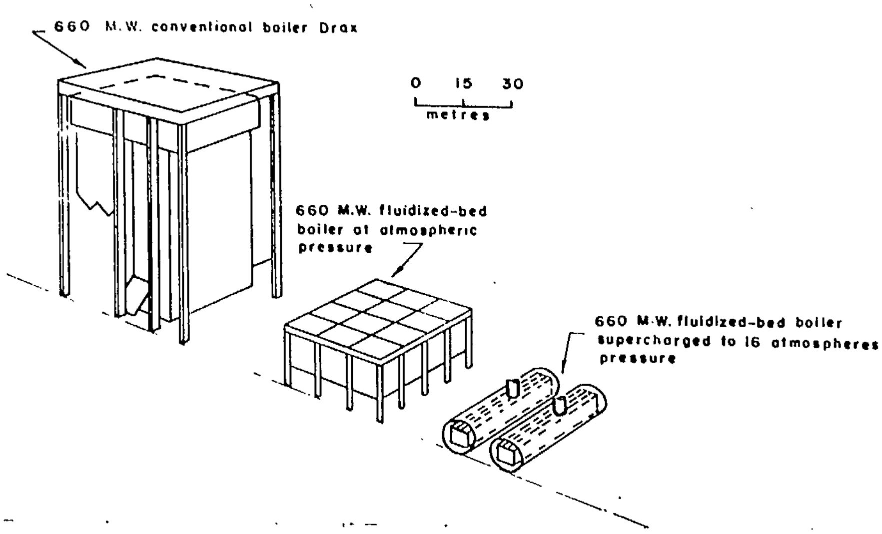


FIGURE 15: Estimated Effect of Fluidized Bed Combustion on Size of Steam Generators.
Taken from "Fluidized Combustion for Western Fuels", by H.B. Locke and A. Orr.

COMBINED HEAT-POWER PLANTS

A technique with great potential for energy conservation.

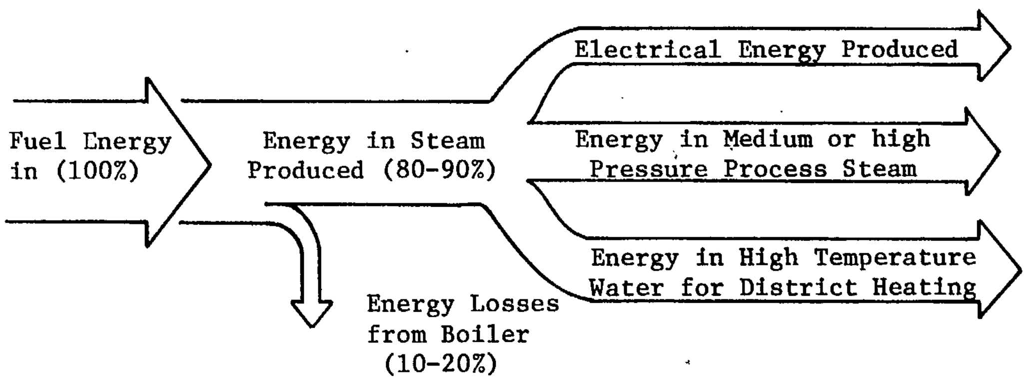


FIGURE 16: Sankey Diagram; Energy Conservation Potential of Combined Heat-Power Systems