Technical Publication

The Influence of Fuels on Boiler Design

by

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The purpose of this paper is to discuss the boiler design requirements dictated by the fuels commonly used in electrical generating power plants. These fuels include natural gas, No.6 oil, crude oil, bituminous or sub-bituminous coals, and lignite. We will not include data on some of the more unusual industrial fuels such as bagasse, blast furnace gas, carbon monoxide gas or fluid coke which at least give variety to the boiler designer's work.

For over twenty-five years I have been telling our salesmen in the field that the first step in boiler design is to have a clear understanding of the fuels that will be fired. This means we need a fuel description together with a fuel analysis, and a clear understanding of the range of the fuels the steam generating unit is expected to fire. In the case of coal, a chemical analysis of the ash should be available. In fact, there are very few aspects of boiler design work that are not influenced by the fuels the unit is expected to use.

NATURAL GAS

Natural Gas is the easiest fuel for the boiler designer and the boiler operator to work with. This fuel permits the smallest furnace, with area heat releases of approximately 200,000 Btu per sq. ft. of furnace envelope. Superheater, reheater and economizer tube bundles can be tightly spaced, and soot blowers are not required. Flue gas velocities of 120 ft. per second are acceptable (provided anti-vibration measures are taken in the tube bundle) because there is no fly ash erosion. Finned ėconomizers with five fins per inch are standard for Riley designs, and closely packed Ljungstrom air heater surfaces are acceptable. The pressure furnace arrangement without induced draft fan is popular for this fuel. Induced draft fan investment, maintenance, and horsepower are eliminated. The only real problem with natural gas as a fuel is that, because of questionable future supplies, nobody wants to buy a large unit limited to this one fuel. Figure 1 illustrates a typical natural gas fired, pressurized boiler for Western Farmers Electric Cooperative at Moreland, Oklahoma, with a capacity of 1,000,000 pounds of steam per hour, 1950 psig, 1005°F steam and reheat temperature.

NO. 6 OIL

The furnace for No. 6 oil should be sized such that the area heat release is a maximum of approximately 200,000 Btu per sq. ft. of furnace

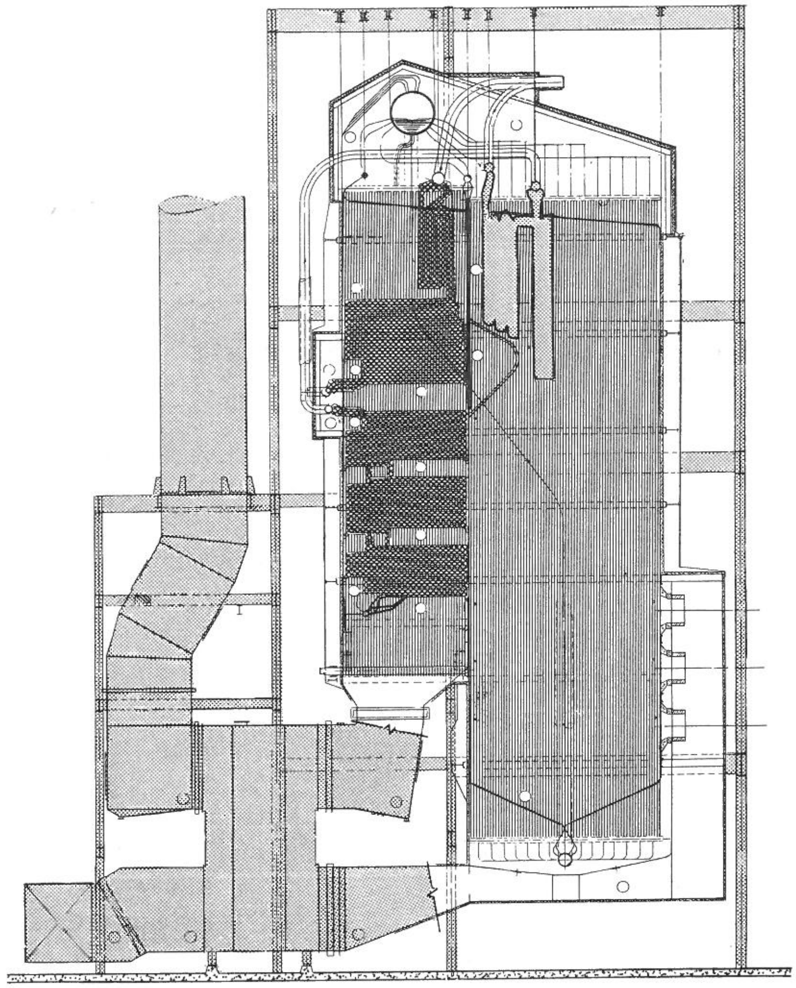

FIGURE 1 WESTERN FARMERS ELECTRIC COOPERATIVE, MORELAND, OKLAHOMA

envelope. We recommend that at least a portion of the furnace be constructed of an alloy tubing if the superheater outlet pressure is 2400 psig or more. Furnace wall blowers are not ordinarily needed unless the oil is particularly high in sulphur and vanadium. High sulphur oils, of course, are no longer popular now that there is great concern with enviromental problems. Furnace wall blowers are required on combination oil-gas units for quick change over from oil to gas firing. Soot blowers are required in locations where the gas temperature is 1900°F or less, and tube bundles must be limited to approximately 8 ft. in height for effective soot blower cleaning. For this fuel we use gas velocities of 100 ft. per second through the tube bundles. If the superheater outlet steam temperature is 1000° F, we may need some stainless steel in the superheater tubing, particularly on those units designed for a furnace area heat release of 200,000 Btu per sq. ft. as the upper limit.

In order to assist in reducing NOx emissions, it is frequently specified that No. 6 oil fuel be fired with low excess air. Riley Stoker Corporation has developed a double register burner that operates at 5% excess air and, when this burner is used with a compartmented windbox, 3% excess air operation is possible. In addition, provisions can be made for operating the lower burners at less than stoichiometric air and adding the balance of air for combustion in the upper burners or, alternatively, by means of injection ports above the upper burners. Larger furnaces and greater vertical and horizontal spaces between burners will reduce oxides of nitrogen concentrations.

At the back of the unit, finned economizers are limited to three fins per inch and closely packed Ljungstrom air heater surfaces are not permissable. Please note that the differences between natural gas and No. 6 oil design requirements in the air heater surface arrangement, in the economizer fitting, in the spacing required for soot blowers, and in the gas pass velocity make it very difficult to convert a gas fired boiler to a No. 6 oil fuel fired unit.

Figure 2 illustrates an oil fired unit with a capacity of 3,250,000 pounds of steam per hour, 2025 psig operating pressure, 955°F main steam and reheat temperature, for peaking duty. This unit is under construction at the Salem Harbor Massachusetts plant of New England Power and a duplicate unit has been ordered for their Brayton Point, Massachusetts, plant.

CRUDE OIL

This is the newest fuel available for utility steam generating units in America. This fuel appears to be superior to No. 6 oil in that it is lower in percentage of sulphur, vanadium and ash. Until we have more experience with crude oil, we are using the same design parameters as we use for No. 6 oil. Japanese power plant practice is to use mechanical atomizing burners but the Riley Stoker units to be fired with crude oil will use either steam atomizing or mechanical atomizing burners at the customer's option. Every precaution should be taken to avoid leaks in the

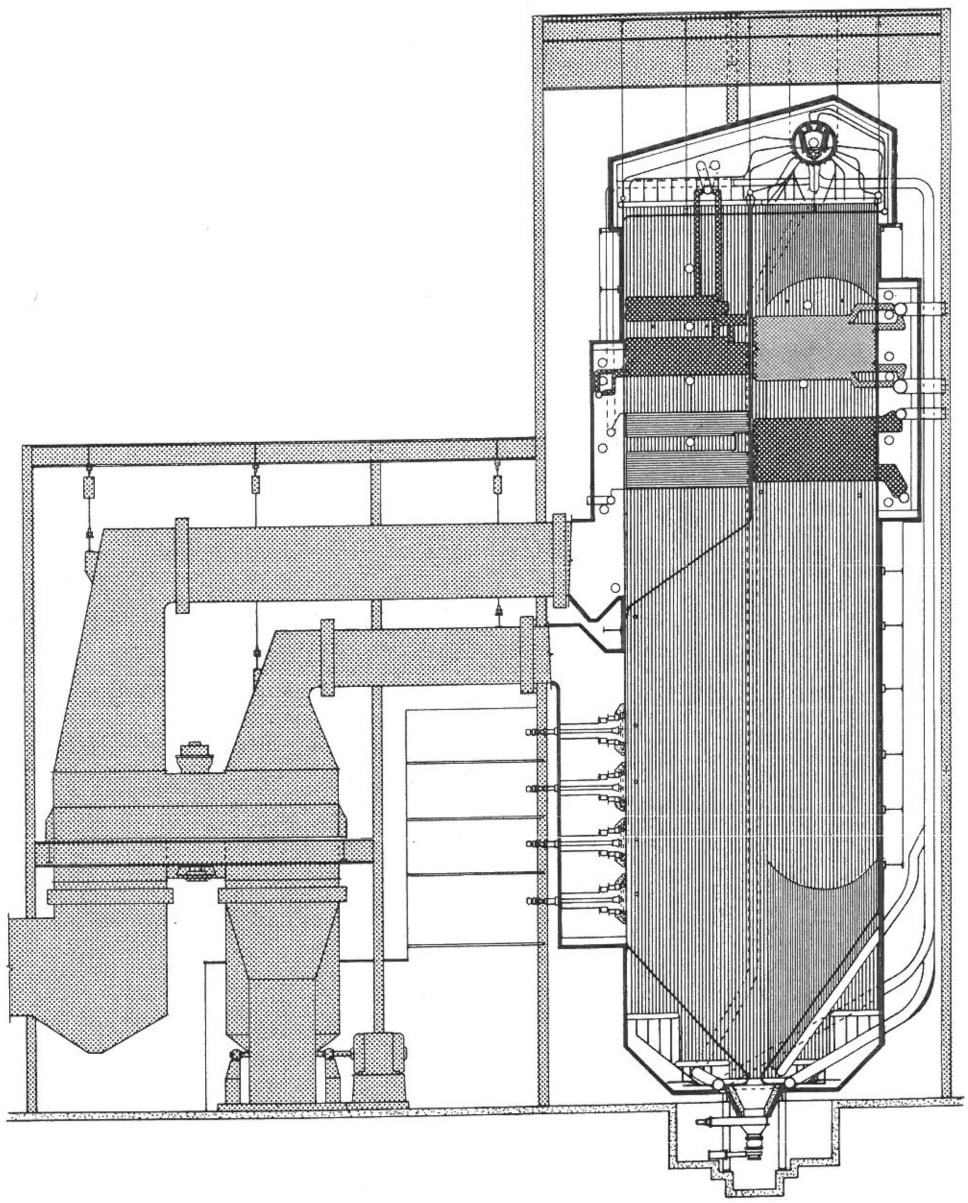

FIGURE 2 NEW ENGLAND POWER COMPANY, SALEM HARBOR STATION, UNIT NO. 4
SALEM, MASSACHUSETTS

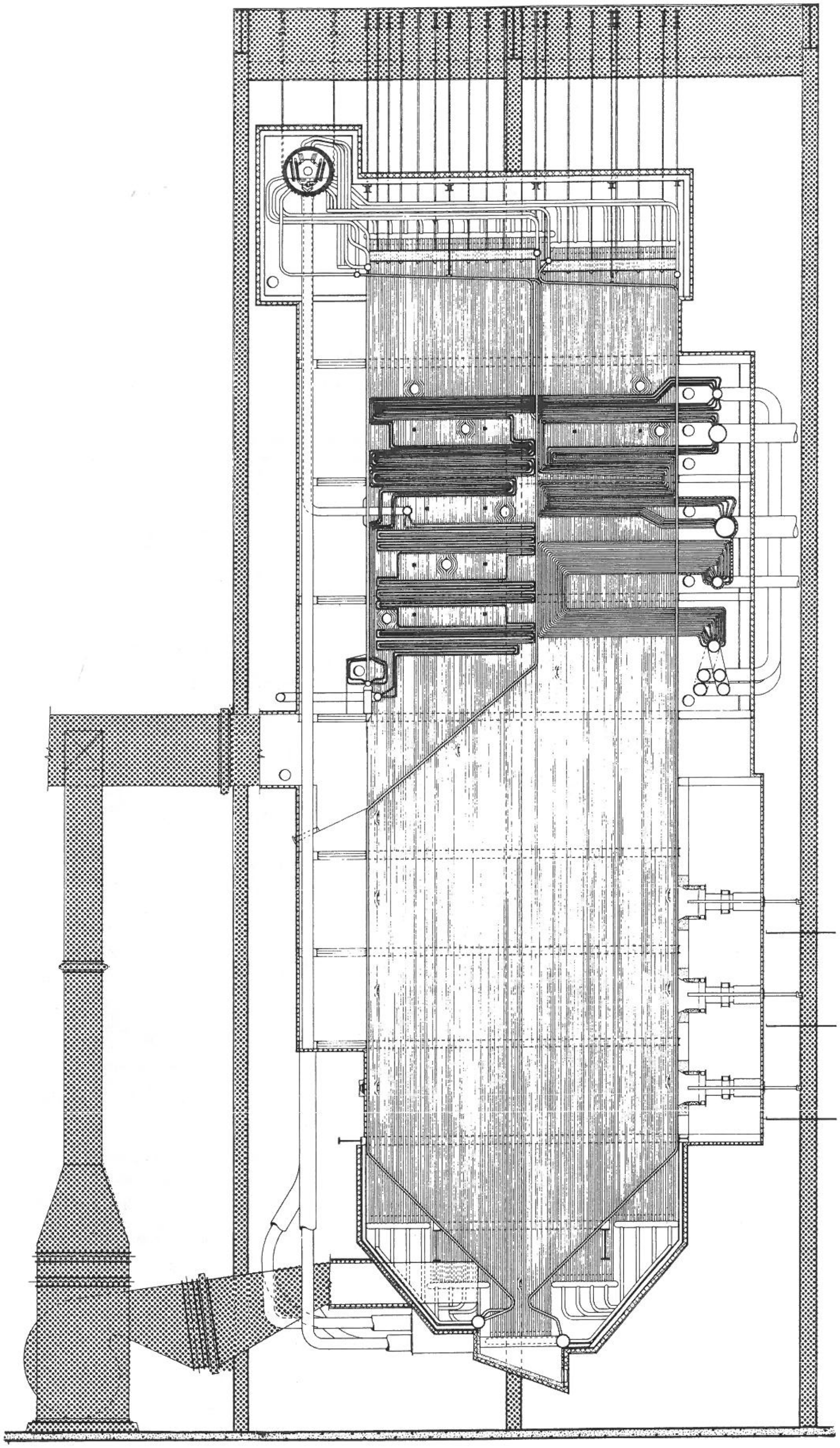

FIGURE 3 CONSUMERS POWER COMPANY, DAN E. KARN PLANT UNIT NO. 3
(near) ESSEXVILLE, MICHIGAN

fuel piping system and we recommend explosion-proof and non-sparking equipment in the firing aisle area.

Figure 3 illustrates the Consumers Power Co. unit for crude oil firing with a capacity of 4,650,000 lbs. of steam per hour, 1980 psig operating pressure, 955°F steam and reheat temperature.

BITUMINOUS AND SUB-BITUMINOUS COALS

Our first concern in designing a boiler for these coals is the minimum softening temperature of the ash in the coal because our furnace envelope requirement is dictated by this figure. We maintain a flue gas exit temperature of at least 100°F below the ash softening temperature. If the ash softens at 2200°F we need 2100°F as a furnace exit temperature and this requires approximately 80,000 Btu per sq. ft. furnace area heat release. But if the ash softens at 2000°F we want a 1900°F furnace exit gas temperature and we therefore need a furnace with an area heat release of approximately 60,000 Btu per sq. ft. Note that this difference of 200°F in the ash softening temperature dictates 33% more effective projected radiant surface in the furnace.

It is not economical to design for all possible future coals. If the possibility of using some particularly troublesome coal is rather remote, a good compromise may be to de-rate the unit while temporarily firing poor quality coal.

Our second consideration is the slagging factor of the ash. A complete chemical analysis of the ash is required, and the ratio of basic compounds to acid compounds is determined. The basic compounds include iron, calcium, magnesium, potassium and sodium oxides. The acid compounds include silicon, aluminum and titanium oxides. This basic acid ratio times the sulphur in the coal determines the slagging factor and allows us to classify the coal as low, medium, high or severe. It follows that the troublesome coals are those with high sulphur in the coal and high basic elements in the ash. The slagging factor determines the number of furnace wall blowers and furnace volume requirements. When a new source of coal is under consideration for an existing unit, the slagging factor will determine if more furnace wall blowers will be needed.

Our third consideration is the fouling factor of the ash. This is determined by the basic acid ratio and the sodium oxide content of the ash. The factor classifies the coal as low, medium, high or severe in expected difficulties in the gas pass. It helps us determine the tube bundle depth and the soot blower requirements.

Bituminous coal dictates other dimensions of the unit. We hold to 60 ft. per minute for gas pass velocity. Finned economizer surface is limited to two fins per inch and the fins are of thicker material than for other fuels. Reheater and superheater tube bundles are spaced on 4-1/2 in. centers. There are some advantages to the large furnaces required by pulverized coal. Alloy tubing is not needed in furnace walls and stainless steel is generally not required in the superheater tubing.

At the rear of the unit wet scrubbers can be added to remove sulphur compounds and precipitators are used to remove flyash. It is difficult to predict oxides of nitrogen level in the flue gas from pulverized coal furnaces, but a value appreciably higher than oil or gas firing can be expected.

Figure 4 shows the Hoosier Energy Division pulverized coal fired unit with a capacity of 830,000 lbs. of steam per hour, 1575 psig operating pressure, 1005° F main steam and reheat steam temperature.

LIGNITE

While natural gas is the fuel permitting the smallest steam generating unit dimensions, lignite is the fuel requiring the greatest generosity in boiler components. The big advantage of lignite over other fuels is that it is the lowest cost fuel on a million Btu basis, at least at the mine. Its use dictates the need for twice as much pulverizing capacity. Crusher drying equipment is needed ahead of the pulverizers. Our lignite designs call for more wall blowers and soot blowers than any other fuel, bare tube economizers without fins, and tube bundles spaced on 6 in. centers throughout the gas pass.

TURBINE EXHAUST GAS

When a power plant has gas turbine generators for emergency or peaking capacity, the turbine exhaust gas containing about 75% air is an excellent source of preheated air and can be used in a steam generating unit supplying steam to a steam turbine generator. The most economical arrangement giving the lowest overall plant heat rate comes when the gas turbine generator is selected for 20 to 25% of the combined cycle output and the steam generator supplies 75 to 80% of the output. The fuel in the steam generating unit can be oil or coal, conserving more expensive natural gas for the gas turbine. Turbine exhaust gas requires a large economizer in place of the air heater. Figure 5 illustrates the unit selected by Taunton Municipal Lighting Plant in Massachusetts to deliver 557,000 lbs. of steam at 1875 psig and 1005° F main steam and reheat temperature. The unit produces full steam capacity on fresh air firing when the gas turbine exhaust is not available. With the gas turbine in operation supplying 846,000 lbs. of gas at 940° F, the oil requirement to the unit is cut by 20%.

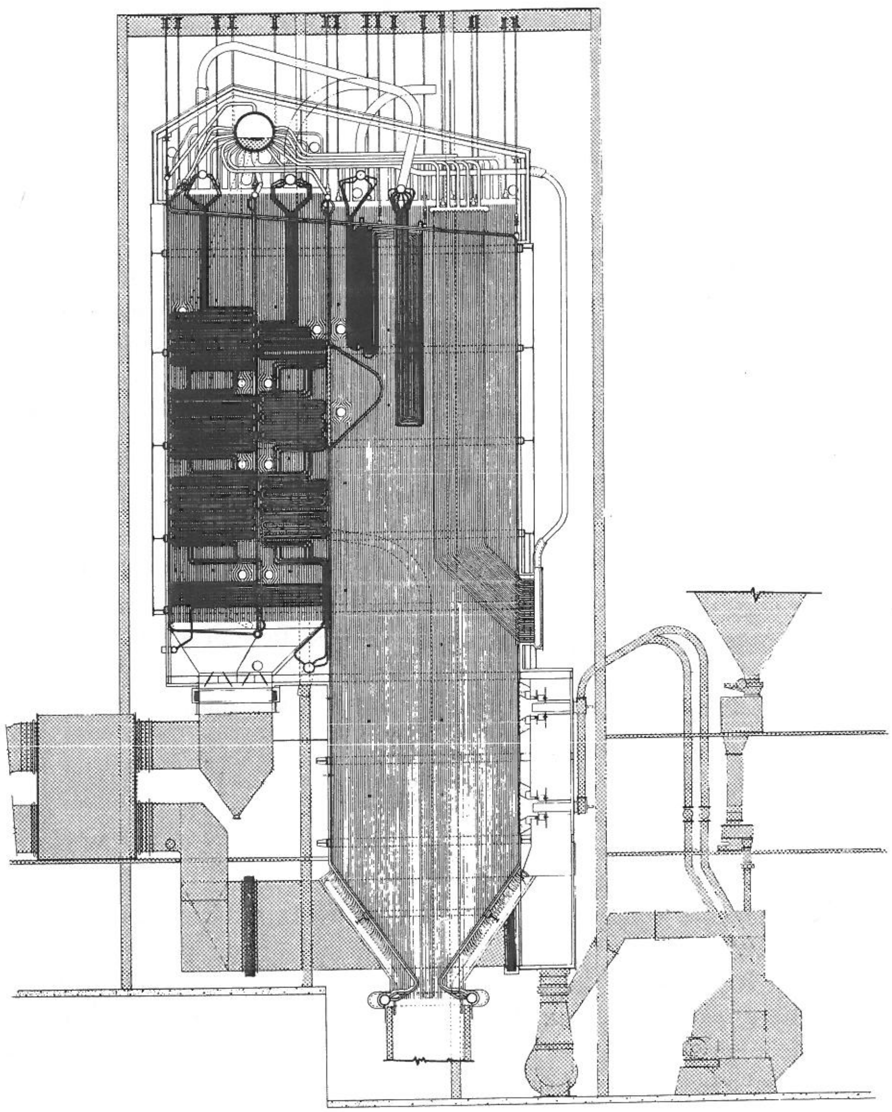

FIGURE 4 HOOSIER ENERGY DIVISION, INDIANA STATEWIDE RURAL ELECTRIC COOPERATIVE INC., PETERSBURG, INDIANA

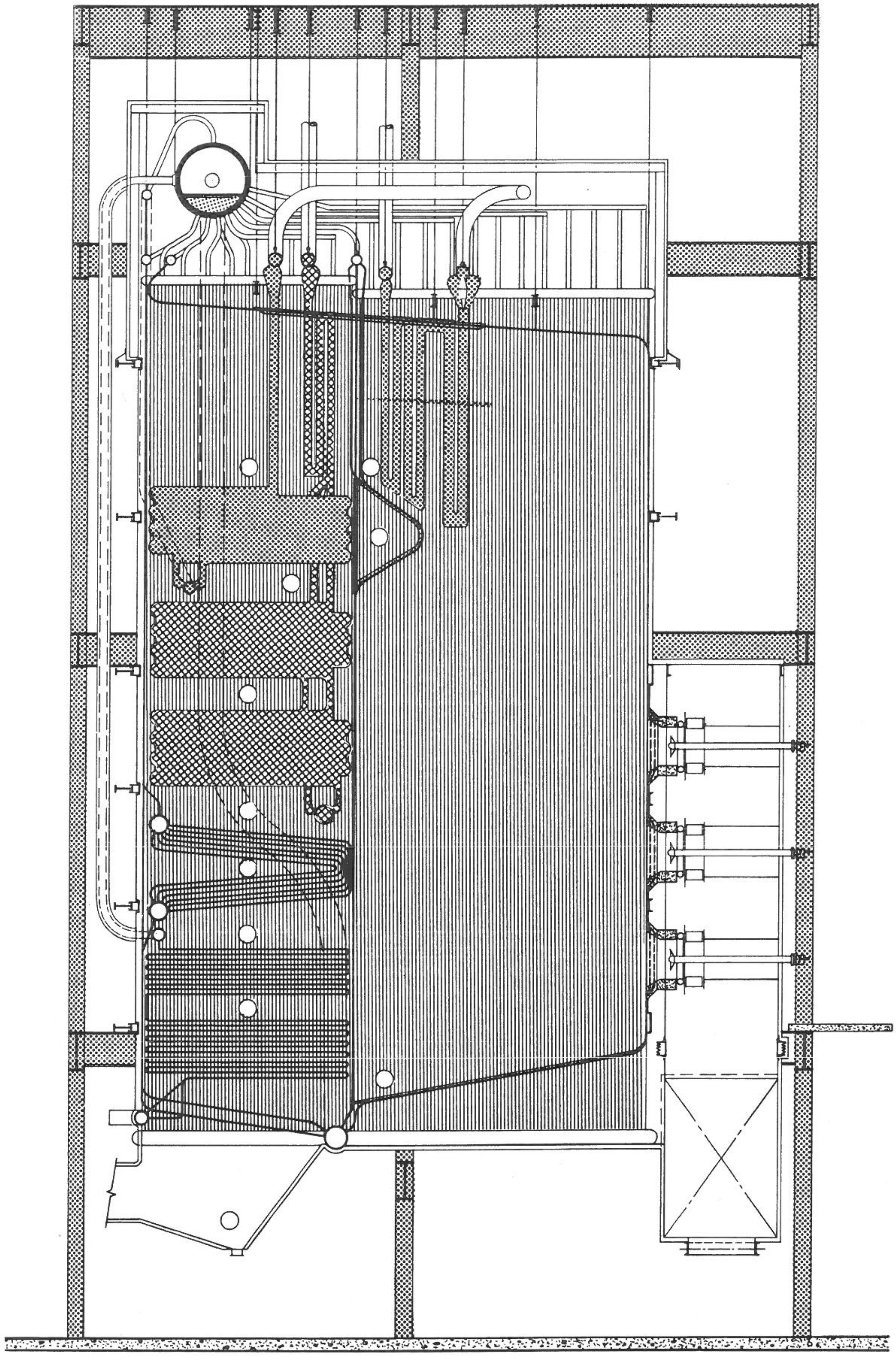

FIGURE 5 TAUNTON MUNICIPAL LIGHTING PLANT, MAYOR D. F. CLEARY STATION, TAUNTON, MASSACHUSETTS

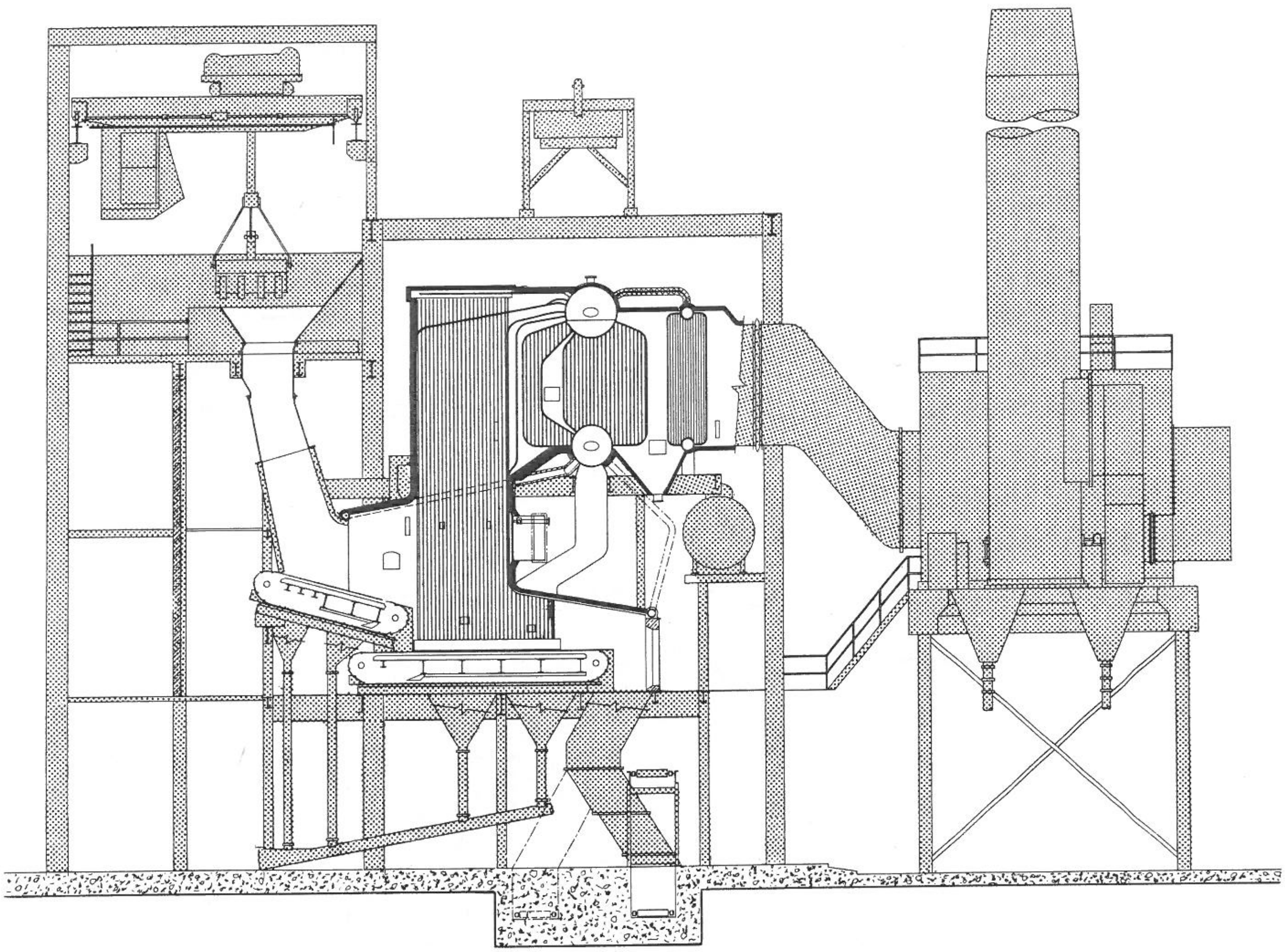

FIGURE 6 MUNICIPAL REFUSE INCINERATOR, TOWN OF BRAINTREE, MASSACHUSETTS

MUNICIPAL WASTE

One additional fuel can be mentioned for use by utilities in the future. The quantity of municipal waste is increasing annually and the quality is improving (on a Btu/lb basis). Wet garbage is now a smaller percentage, and dry wood, paper, plastics and cardboard are greater percentages than before. The Riley Stoker Corporation installation for the City of Braintree, Massachusetts, (see Figure 6) uses two stokers, one for drying and one for burning, followed by a single pass boiler bank with in-line tube arrangement. It is a low capacity, low pressure unit but we are now prepared to quote on municipal waste fired steam generating units for 500,000 lbs. of steam per hour using three stages of stokers.

CONCLUSION

It is difficult for generating plant operators to predict the source of their future fuels, especially future coals, or even if they will be firing coal at all! But if limits are not placed on the slagging, fouling, fusion and grindability characteristics of the coal, the steam generator becomes unnecessarily large. The best compromise between fuel and unit design requires close cooperation among the operator, the consultant and the boiler supplier in the early stages of the specification.