GEORGIA-PACIFIC FINDS WEST COAST WOOD-FIRED ELECTRIC GENERATION PAYS OFF

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ABSTRACT

The objective of this paper is to discuss the overall economic justification of adding a new boiler to Georgia-Pacific's Fort Bragg, California sawmill, and to detail the boiler system that is now being erected at the site. The sale of electric power to the neighboring utility is also described. The project has distinctive design and erection elements which will be examined, as well as considerations which led to shop-assembly of the boiler.

BACKGROUND

Georgia-Pacific Corporation operates its largest lumber manufacturing facility at Fort Bragg. This integrated complex is composed of two sawmills, a dry kiln operation and facilities for surfacing, storage, shipping and maintenance. Ten years ago this plant produced approximately 440 thousand board feet daily. Today, after two major overhauls in critical production areas, the entire complex is tallying over 1 million board feet daily, operating 220 days a year[1]. The majority of the wood processed at Fort Bragg is redwood timber.

The Fort Bragg facility is located on the shore of the Pacific Ocean and is bordered on one side by the downtown section of the City of Fort Bragg. The entire western boundary of the facility is directly above the beach area of Fort Bragg. Due to its location, environmental concerns for the land, water and air are critical. These concerns are of paramount importance to Georgia-Pacific and to the community.

Up to 1981, the boiler plant consisted of two dutch oven-fired 1034 kPa (150 psi) boilers and two superheated 2827 kPa (410 psi) water-cooled grate boilers. The dutch oven boilers, which were installed more than 40 years ago, have been derated to conform with local air pollution requirements. They see only limited service because of their low steam pressure. All existing boilers are wood-fired with oil as back-up.

The amount of wood waste generated by this large facility far exceeded that which could be consumed by the existing boilers and was hauled to a waste disposal site. The local utility, Pacific Gas & Electric Company (PG&E), advised Georgia-Pacific that they would be able to purchase any surplus electric power the plant produces. The plant cannot produce more than approximately 8 MW from the three 5 MW generators installed due to limited high pressure steam availability. Future growth at the mill will require additional electric power.

The local air pollution control authorities have advised that the unscrubbed flue gas from the two dutch ovens is unacceptable and their use must be terminated within 90 days after any new steam generator is placed into service. The mill is located in an EPA-designated "non-attainment" area, in regard to particulate emissions. It was discovered that the State of California did not have an implementation plan acceptable to EPA. Therefore, approval and air quality permit requirements were established by EPA. Modeling of the area for attainment (in this particular case in air particulate and gaseous materials) was handled by the environmental group from corporate headquarters of Georgia-Pacific located in Atlanta, Georgia. An air quality permit was issued stating that the emissions of particulate from a new boiler must not exceed .03 grains per dry standard cubic foot of flue gas discharged.

The maintenance costs of the existing boilers and dutch ovens were excessive due to overloading. A high degree of maintenance on the induced draft fans has been required due to unit overloading. The amount of carryover of particulate was excessive. In addition to the overfiring of these units on wood, it was often necessary to add a considerable amount of oil firing to maintain steam production. This high cost of maintenance, plus added fuel oil cost, has made the production and sale of surplus power only marginally attractive. In 1978 Georgia-Pacific considered adding a new wood-fired boiler to the power plant, and retained Nor'West Pacific Division of Trans Energy Systems (TES) to make recommendations in regard to a new facility as well as improvements to upgrade the power plant and utilize surplus wood wastes. The study showed that a reasonable return on investment could be achieved by increasing the electric production, burning the surplus wood waste as fuel. There was sufficient space to install a new boiler in the existing boiler plant to meet anticipated steam needs.

Georgia-Pacific determined that a new steam generating unit would relieve the overload duty being put on the older boilers and consequently reduce the high maintenance costs. In addition, a new boiler would mean surplus electric power available for profitable sale to PG&E.

As a result, Georgia-Pacific authorized the construction of a new boiler complex. Nor'West Pacific Division of TES issued bid specifications which were very explicit in regard to type of material to be burned, guarantees for emission and steam capacity and limited boiler erection space. The boiler manufacturer's scope of supply was to consist of the entire boiler including support steel, FD and ID fans, airheater, dust collector, scrubber, stack and a complete burner management system for firing oil as an alternate fuel. Riley Stoker Corporation was the successful bidder with a Shop Assembled Modular boiler.

The overall program also included the installation of two water treatment plants for reclaiming water from an existing log pond and from a groundwater runoff source. Also to be installed were a new ash handling system and a new cooling tower system.

ECONOMIC JUSTIFICATION

In 1978, surplus power was being purchased from the plant by PG&E at approximately 2 cents/kWh on a non-firm basis. The sale of potential surplus electricity, combined with reduced maintenance costs and reduced cost of disposal of surplus wood waste, indicated a favorable rate of return on investment could be obtained for a new boiler addition. Since that initial evaluation, many factors used in its determination have changed. The cost of the additional fuel oil used to produce adequate steam has dramatically increased. So have the costs of maintenance and hauling away surplus wood. The purchase price of electric power by the utility has varied from 2 cents/kWh to 7.9 cents/kWh, and is currently below 5 cents/kWh.

In 1981, the economic justification for the plant was recalculated to evaluate the final environmental permits, waste water permits and the general costs including the potential electric sales costs. The results again indicated that a favorable return on investment could be obtained. Forecasts were obtained from PG&E in 1982 regarding projected electric rates. In commenting on these projections, PG&E made it very clear that they were based only on recent forecasts as of March, 1982 and that they were not representing or warranting them for accuracy or correctness for future years. The data indicated some rather startling figures. For example, in 1990 the rate for electric power in the large light and power category, which includes the Fort Bragg mill, goes from 7.68 cents/kWh in 1983 to 14.28 cents/kWh. PG&E's projection for the year 2000 indicates a price of 27.26 cents/kWh or nearly four times the 1983 rate. It logically follows that the price the utility will pay for non-firm surplus power will in turn go up. A copy of the published projections by PG&E is shown in Table I.

PACIFIC GAS & ELECTRIC COMPANY
NOMINAL ELECTRIC PRICES**
($/kWh)

Year	Large Light and Power	% Change
1981*	0.0575	
1982	0.0829	44.15
1983	0.0768	−7.33
1984	0.0935	21.84
1985	0.0950	1.50
1986	0.1023	7.70
1987	0.1100	7.49
1988	0.1209	9.92
1989	0.1309	8.30
1990	0.1428	9.10
1991	0.1567	9.73
1992	0.1711	9.16
1993	0.1825	6.65
1994	0.1933	5.93
1995	0.2017	4.34
1996	0.2156	6.92
1997	0.2186	1.39
1998	0.2389	9.30
1999	0.2594	8.55
2000	0.2726	5.10
2001	0.2910	6.75
2002	0.3106	6.75

COMPOUND ANNUAL GROWTH RATE

1981-1990	10.64
1990-2002	6.69
1981-2002	8.36

*1981 - Recorded

**includes inflationary effects

Pacific Gas & Electric Company
March 1982

Table I Pacific Gas & Electric Company Nominal Electric Prices

In addition to the sale of surplus electric power, it is anticipated that in the next 10 to 15 years growth and modernization will occur at this mill. The mill's in-house electric needs will also increase. Manufacturing costs can be greatly reduced by in-house generation of electric power.

In 1983, additional income from the sale of an average of 6 MW of surplus energy at the PG&E expected purchase price of 5 cents/kWh will amount to $216,000 per month of operation. This amount, in 1990, on a similar proportionate basis of expected purchase versus sales price (5 cents/kWh versus 7.68 cents/kWh in 1983; 9.3 cents/kWh versus 14.28 cents/kWh in 1990), would show an income on 6 MW of $401,760 per month of operation. These amounts are gross figures which do not include operation, maintenance and fuel prepearation charges. Substantial savings in manufacturing costs will result from increased in-house power generation.

DESIGN DESCRIPTION

General

At the time that this project was bid, Riley had just introduced its solid fuel-fired Shop Assembled Modular boiler series. The design was based upon proven concepts demonstrated in field-erected units, coupled with packaging techniques perfected in other product lines. Use of this boiler in lieu of a field-erected unit was chosen by Georgia-Pacific due to reduced costs and shortened overall construction time.

The Shop Assembled Modular boiler designed for use at Fort Bragg is a twin-furnace single boiler bank design. Although a steaming capacity of 63,503 kg/hr (140,000 lbs/hr) was specified for this unit, a design incorporating twin furnaces, each rated 34,019 kg/hr (75,000 lbs/hr), was chosen, based on the wood residues to be fired. The size composition by weight showing 59% of the material to be 6.35 mm (1/4 in) or under, and having a relatively high moisture content suggested that a generous furnace volume would be appropriate.

There were five major component groupings that were completely shop-assembled and field-erected in sequence: two stoker modules, two furnace modules, two superheater modules, a boiler module, and two tubular airheater sections. In addition, the dust collector and wet scrubber were purchased and installed as modular units. Figure 1 depicts this modular concept. The unit was designed for dual fuel capability utilizing either redwood hog fuel or #5 fuel oil. The typical analysis of each of these fuels is shown in Table II.

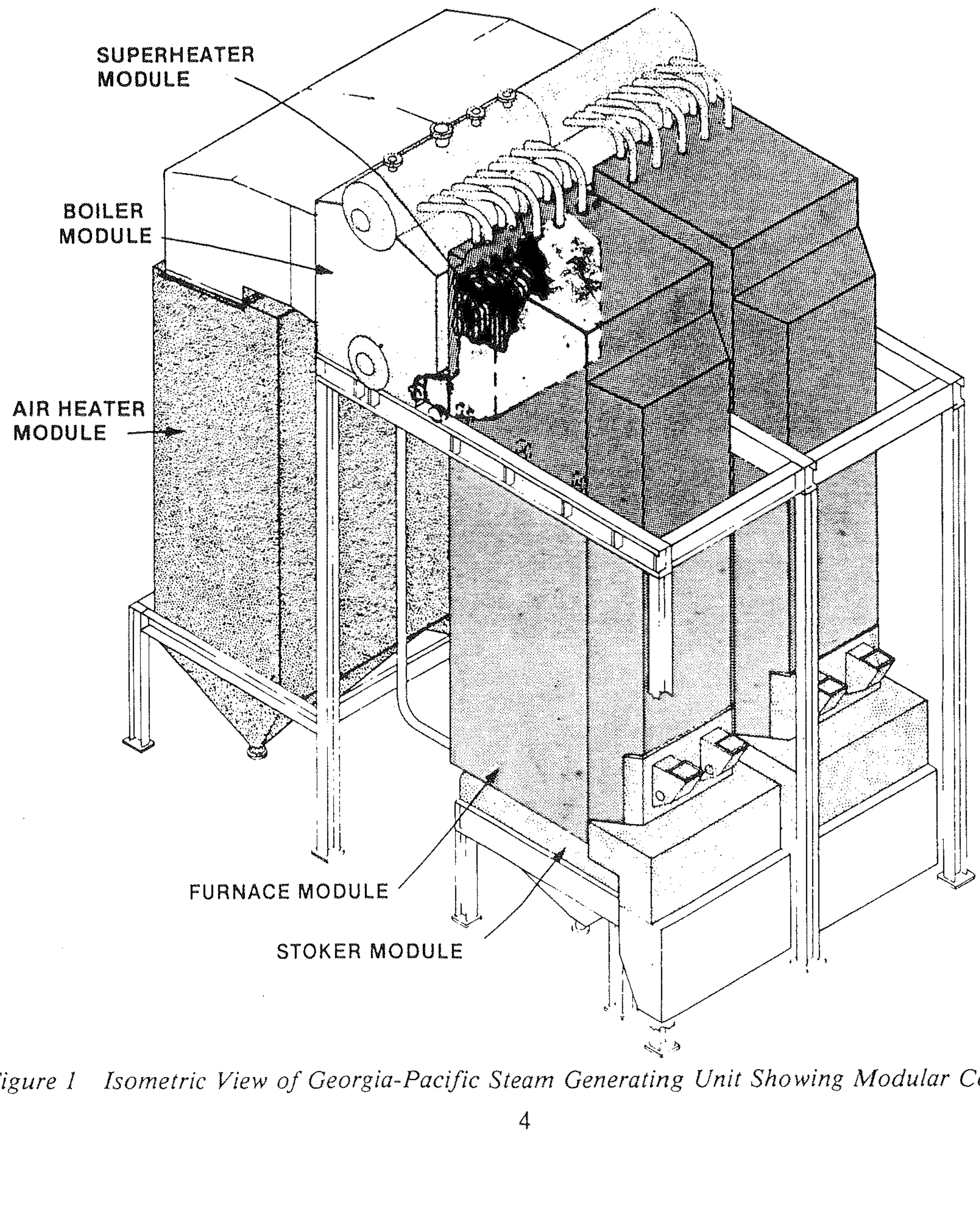

Figure 1 Isometric View of Georgia-Pacific Steam Generating Unit Showing Modular Concept

Redwood Hog Fuel		#5 Light Fuel Oil	
Constituent	**Percentage**	**Constituent**	**Percentage**
Ash	.92	C	85.6
H	2.55	H	11.7
C	22.09	O and N	.7
H_2O	56.0	S	1.6
O	18.29	Other non-combus-tibles and H_2O	.4
N	.14		
S	.01		
TOTAL	100.00	TOTAL	100.0

Table II Fuel Analysis for Georgia-Pacific Boiler

The design pressure and temperature for the boiler is 2758 kPa (400 psi) and 385°C (725°F) respectively, resulting in approximately 138°C (280°F) of superheat temperature leaving the unit. Feedwater temperature entering the boiler was specified at 109°C (228°F).

Stoker Modules

The unit was designed to utilize two Riley Traveling Grate Stoker modules. Each grate is 3050 mm (10 ft) wide by 4270 mm (14 ft) long from shaft center to shaft center and is supplied with its own hydraulic drive enclosed in an oil- and dust-tight housing. Each stoker module was split into two halves, but otherwise fully assembled for shipment (Figure 2).

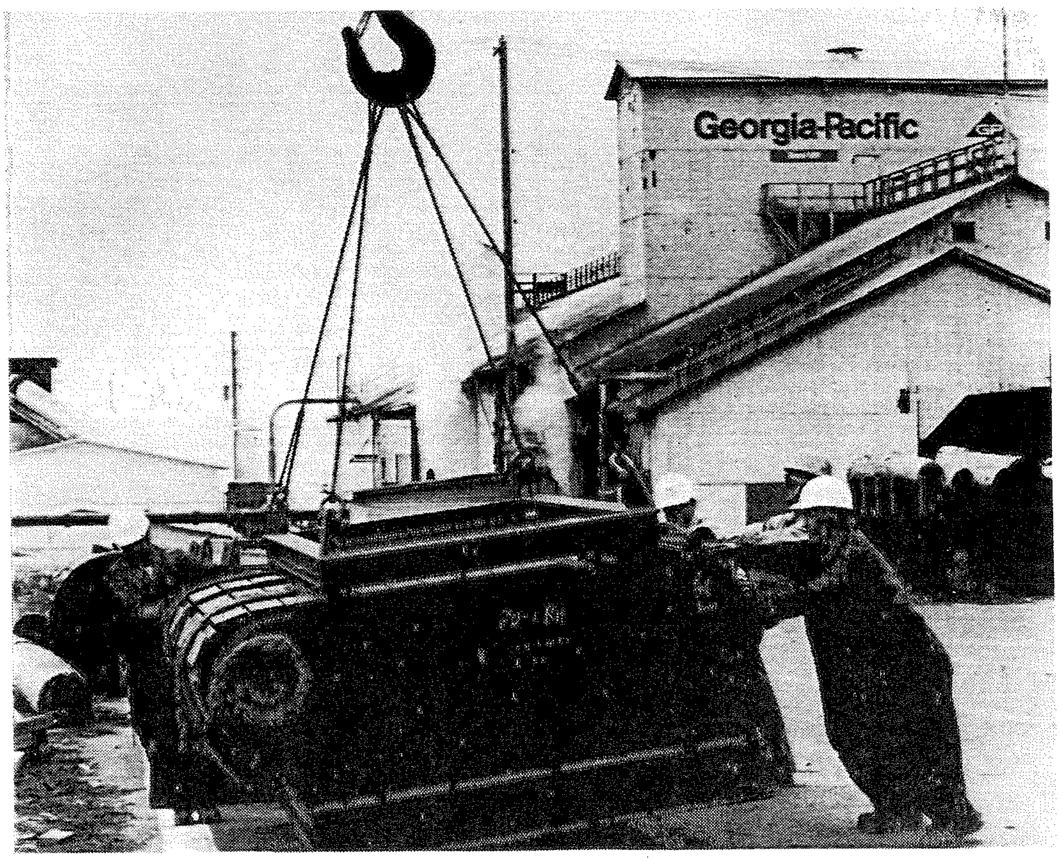

Figure 2 Portion of Stoker Module as Received at Jobsite

The grate was designed with six individually compartmented lateral air chambers. The two rear chambers include adjustable zoning dampers to control air to a minimum as combustion begins. The hogged fuel is deposited uniformly over the grate by means of Riley-designed pneumatic distributors (Figure 3). Air reaches the fuel bed from the air plenum beneath the stoker grate and passes between the NARRO-BAR® grate clips. The major part of the combustion for the larger material that is not burning in suspension takes place in the center of the grate. The resulting ash from the fuel falls from the grate clips at the front of the unit into a lined ash pit where it then can be pneumatically withdrawn by means of an ash removal system.

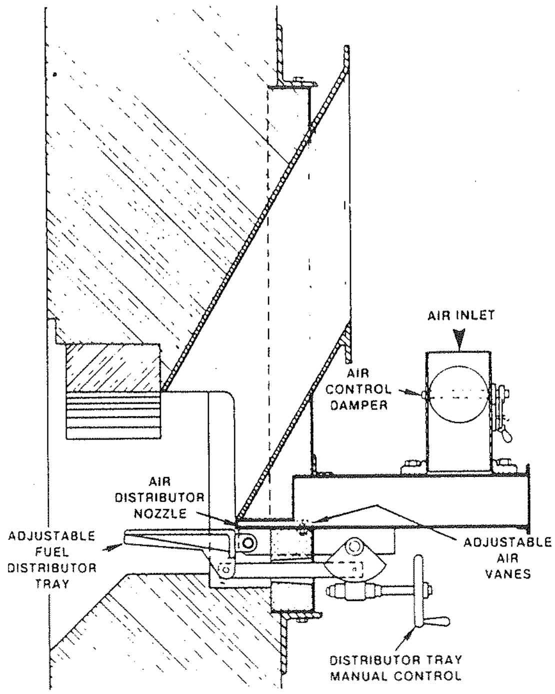

Figure 3 Arrangement of Riley Pneumatic Fuel Distributor on Georgia-Pacific Unit

Combustion Air System

The design of the combustion air system of the unit incorporates several interesting features. First, the system is designed to supply hot air to both the undergrate and overfire air systems in addition to the oil burner windbox. The air temperature is designed to be 285°C (545°F) leaving the airheater at full load when firing wood, and 260°C (500°F) at full load on #5 oil. By using these high air temperatures, the hogged fuel, with a design moisture content of 56%, can be properly dried and burned. The FD and ID fans, the ducts and breeching were sized with the capability of operating at up to 50% excess air as part of the design flexibility.

Figure 4 is a side elevation of the unit as designed, showing location of combustion air flow measurement devices. As designed, the system offers the capability of measuring and controlling both the quantity of air used for combustion and the split between overfire and undergrate when firing the unit on wood. The unit is supplied with five levels of hot overfire air, each level provided with its own remotely-operated shutoff damper.

The boiler furnace and air and gas ducts for the unit have been designed to withstand a transient internal pressure of ±25 in w.g. pressure as required by NFPA 85G Code in effect at the time of contract award.

The addition of a mechanical dust collector and scrubber on the boiler resulted in a high head requirement from the ID fan. It was decided to design the furnace draft controls and burner management system with provisions to prevent or decrease the adverse effects of negative furnace draft excursions which become more

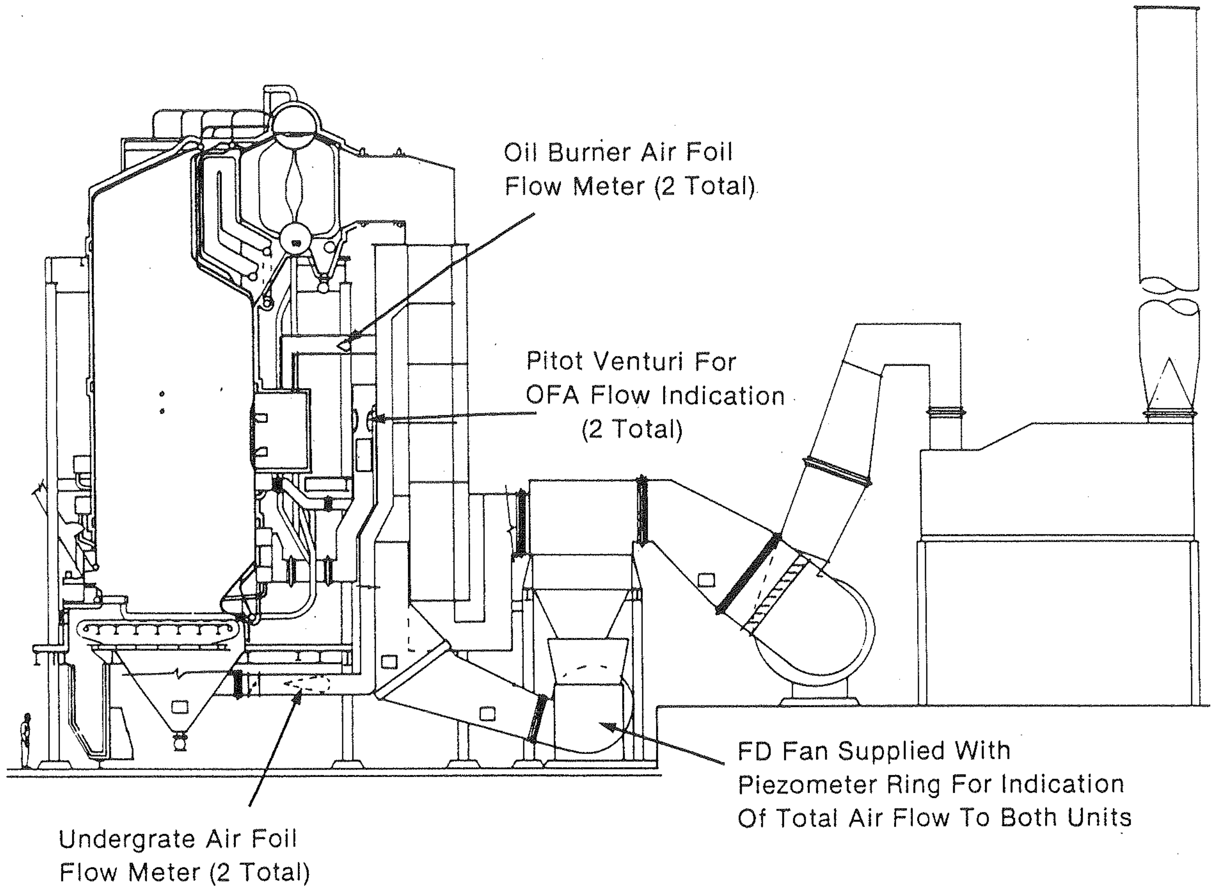

Figure 4   Unit Arrangement of Boiler Showing Locations for Combustion Air Flow Measurement Capability

pronounced with a high head ID fan. Figure 5 shows, in its simplest form, the control system recommended by the NFPA 85G Code.

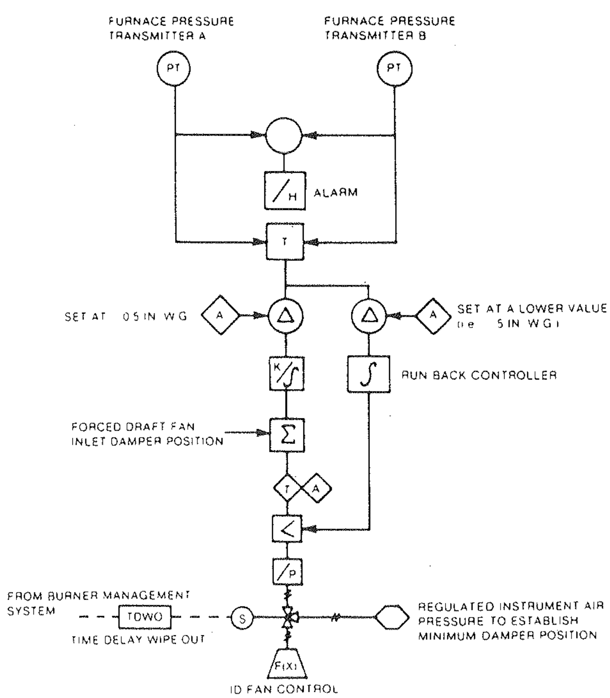

Figure 5   ID Fan Control Logic for Furnace Pressure Control

Two furnace draft pressure transmitters, each connected to a different pressure tap, are required. The operator may select one of them for operation by means of a transfer switch. High deviation between their output triggers an alarm to indicate a malfunction of either one. A conventional furnace pressure control loop has been modified to include a separate runback controller responding to a lower furnace pressure setpoint. The runback controller acts quickly to move the ID fan inlet damper towards a closed position and to correct for a large negative pressure excursion even if the loop is under manual control. Although not a Code requirement, this design concept for controls is consistent with the latest NFPA guidelines for utility and industrial boilers.

When firing oil singly or in combination with the stoker, a total flame failure or master fuel trip timed contact will be available from the burner management system. In the control version represented here, this contact energizes the three-way solenoid valve to send the induced draft fan damper to a predetermined minimum position until the time delay is finished, at which time the solenoid valve will be de-energized to return the damper to the analog control.

For twin-furnace boilers such as this, both furnace pressure transmitters are used, one connected to each furnace, with the higher of the two values used for control. Excessive deviation between transmitter outputs will be alarmed.

The control loop depicted here may be designed in different configurations depending on the hardware and standard designs of the furnace draft control supplier. The figure shown here illustrates conceptual operation only.

Furnace Modules

There were many factors that went into the selection of the furnace size and arrangement. The furnace sizing had to meet shipping tolerances and satisfy both a high degree of conservatism while providing adequate heat content in the flue gas for superheat duty. Table III shows recommended boiler design parameters employed when firing cellulose fuels on traveling and stationary grates[2], and compares these values to the final selections for the Georgia-Pacific unit.

Design Parameter	**Guideline for Cellulose Fuel (w/low sand content)**	**Actual Georgia-Pacific Selection**
Furnace Exit Gas Temperature	899°C 1650°F	811°C 1491°F
Velocity	15 m/sec 50 ft/sec	13.41 m/sec 44 ft/sec
Volumetric Heat Release	186,292-279,439 W/m^3 18,000-27,000 Btu/hr-ft^3	219,804 W/m^3 21,238 Btu/hr-ft^3
Radiant Surface Heat Release	283,950 W/m^2 90,000 Btu/hr-ft^2	166,281 W/m^2 52,704 Btu/hr-ft^2
Traveling Grate Heat Release	3,155,005 W/m^2 1,000,000 Btu/hr-ft^2	3,257,603 W/m^2 1,032,519 Btu/hr-ft^2
Water Cooled Grate Heat Release	3,155,000 W/m^2 1,000,000 Btu/hr-ft^2	N/A

Table III Recommended Maximum Limit Guidelines Versus Actual Selection for Georgia-Pacific Unit

As one can see from Table III, the velocity of the gas is below the recommended limit. Likewise, the radiant and volumetric heat release rates are conservative when compared to recommended upper limits. The basis for this selection is to minimize the carryover of particulate. The fuel consistency is quite fine and a significant amount of burning in suspension is anticipated with this boiler. Although the traveling grate heat release rate is at the upper limit for the Georgia-Pacific selection, we believe it to be justified. The design is based on the amount of fines in the fuel, the quantity and temperature of overfire air, and the high amount of burning in suspension anticipated.

Each module was fabricated of panels and assembled in the shop. Prior to fit-up, the buckstay box beams were welded in place on each panel. Since the module is top-supported at the upper buckstay region, the weight of the panels and lower waterwall headers had be accounted for in the wall thickness selections. Somewhat heavier-walled tubing had to be utilized in the upper half of the furnace to accommodate this weight.

Required shipping clearances were another concern that was dealt with when building these larger-sized furnace modules. The corners of the unit were made bias to reduce the overall clearance required. At the top of the module this required bias bends on tube bundles already bent in one other plane. Figure 6 shows the furnaces on special Riley flatcars.

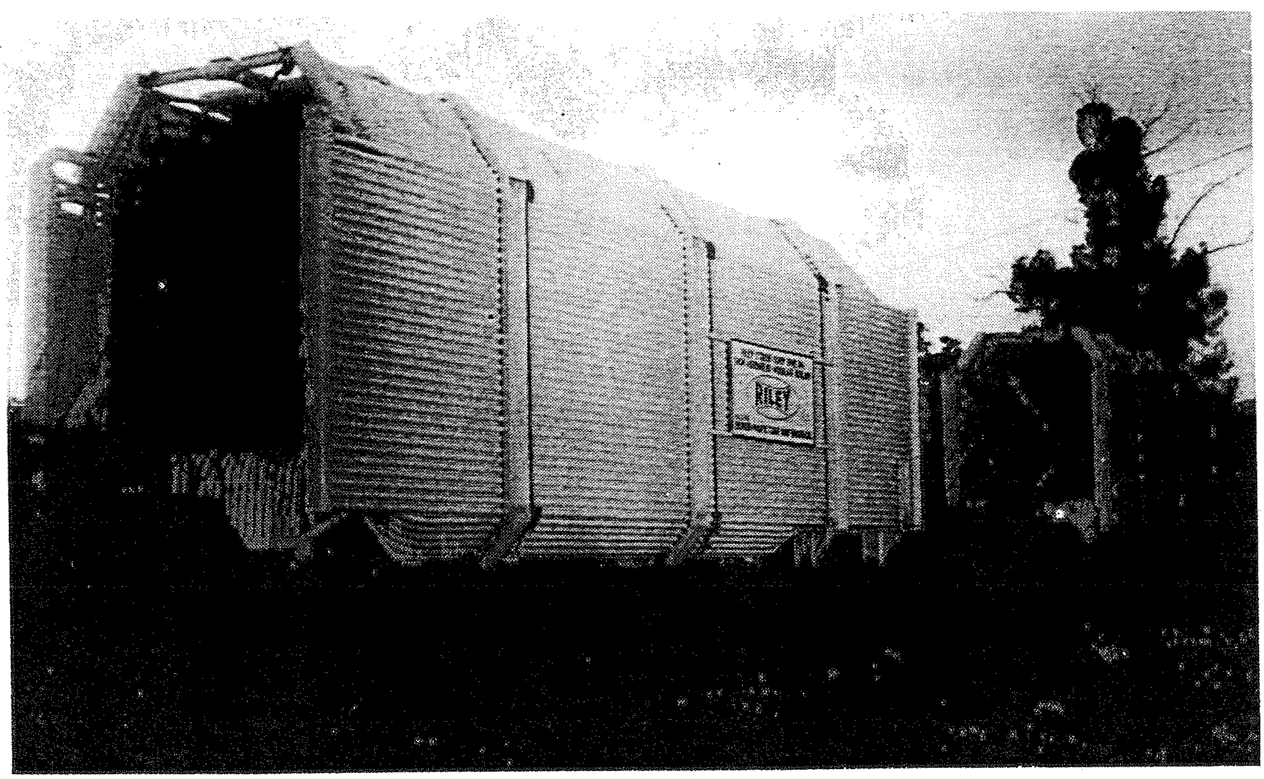

Figure 6 View of Furnace Modules as Received at Rail Siding

Superheater Modules

The shop-assembled superheater modules supplied for the Fort Bragg installation were of a drainable design. The design offers the capability of incorporating either a spray attemperator in the intermediate superheater header or a mud drum heat exchanger for controlling steam temperature. For the Georgia-Pacific unit a mud drum heat exchanger was chosen. The steam temperature control schematic is shown in Figure 7.

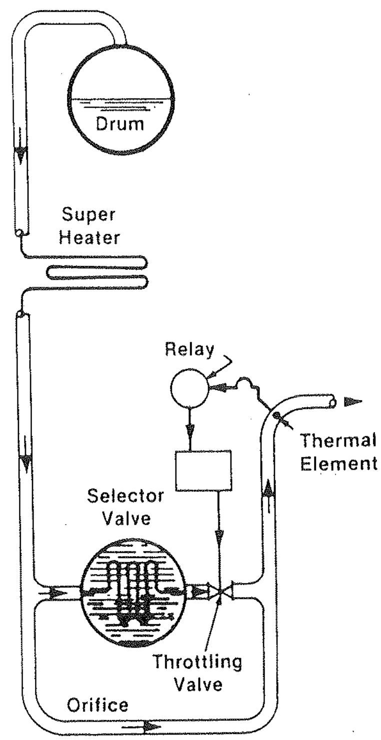

Figure 7   Orifice and Throttling Valve Arrangement for Steam Temperature Control

The quantity of steam passing through the heat exchanger is controlled by a thermostatically-operated flow control valve placed in the return line connecting the heat exchanger drum with the superheater outlet header. The thermostat is placed in the main steam line between the superheater and the turbine. Combustion gas flow and draft loss over heating surfaces are not affected by this control, and all heating surfaces of the boiler unit remain effective at all times. No heat is lost because the heat given off by the cooling system is recovered in the boiler water and used for steam generation.

In order to streamline field erection, the superheater modules were hydrostatically tested in the shop prior to shipment, an advantage possible only with a modular design.

Boiler Module

The boiler module consists of a 1220 mm (48 in) I.D. upper drum with a 914.4 mm (36 in) I.D. lower drum. Centerline distance from upper to lower drum is 3280 mm (10 ft 9 in) and overall length of the module is approximately 9270 mm (30 ft 5 in) with a height of 4780 mm (15 ft 8 in). The shipping weight of the module was approximately 55,338 kg (122,000 lbs).

When firing cellulose fuels such as those that will be burned in Georgia-Pacific boiler, the transverse tube spacing and open areas in the convection bank are not a concern from a fouling standpoint since very little ash is present in the fuel. The main concern is erosion caused by the large quantities of sand that can be present in the fuel. To design for this concern, tube bundle velocities are significantly reduced in this section of the boiler in order to minimize the potential for tube erosion.

The boiler module was completely shop-assembled prior to shipment. All tubes were rolled in the shop.The mud drum heat exchanger was hydro-tested before installation into the lower drum, thus eliminating any potential problem with removal and repair during erection. It was decided not to install the upper drum internals until the unit was erected and a hydro test completed in the field. There was a concern that the weight of the upper drum and the high center of gravity of the overall module might cause some rolled tube joints to leak. In spite of the tortuous shipping path to the site, this was not the case, and hydro of the entire unit was completed in the field without a single tube leak. Figure 8 shows the completed boiler module prior to shipment by rail.

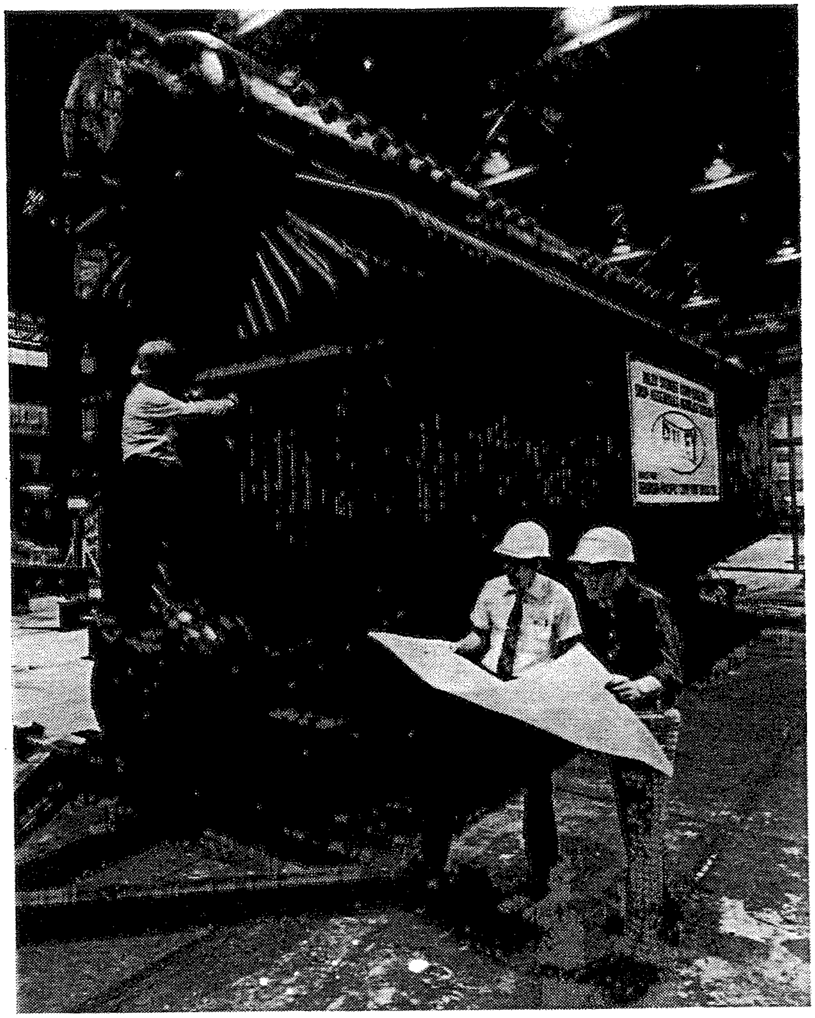

Figure 8   Completed Boiler Module Ready for Shipment

Airheater Modules

There were two airheater modules supplied for the unit. Each module is approximately 3840 mm (12 ft 7 in) high by 3450 mm (11 ft 4 in) wide by 10,850 mm (35 ft 7 in) long (Figure 9). The shipping weight of each module was approximately 41,730 kg (92,000 lb). When received at the jobsite, the two modules were joined together in the raised position, bolted and then seal-welded to form an air- and gas-tight enclosure. Each module included part of the hot air duct to each furnace, thereby reducing the amount of additional duct to be designed and fabricated. This also simplified the insulation and lagging work on ducts.

ERECTION HIGHLIGHTS

Georgia-Pacific's unit is the largest Shop Assembled Modular boiler offered. Its physical dimensions created some challenges when it came time to ship the modules to Fort Bragg from the Riley plant in Erie, PA. Rail transportation was employed for all the modules to the Coast Range mountains in northern California. The furnace modules could not be rail-shipped beyond Cloverdale, some 129 km (80 miles) from the plant in spite of the bias corners provided. The boiler and airheater modules were shipped to Williams, approximately 217 km (135 miles) from the plant. Either weight or dimensional limitations of certain tunnels or bridges between those points and the job site prevented further rail shipment. The balance of the trip over the Coast Range was completed by truck as shown in Figure 10.

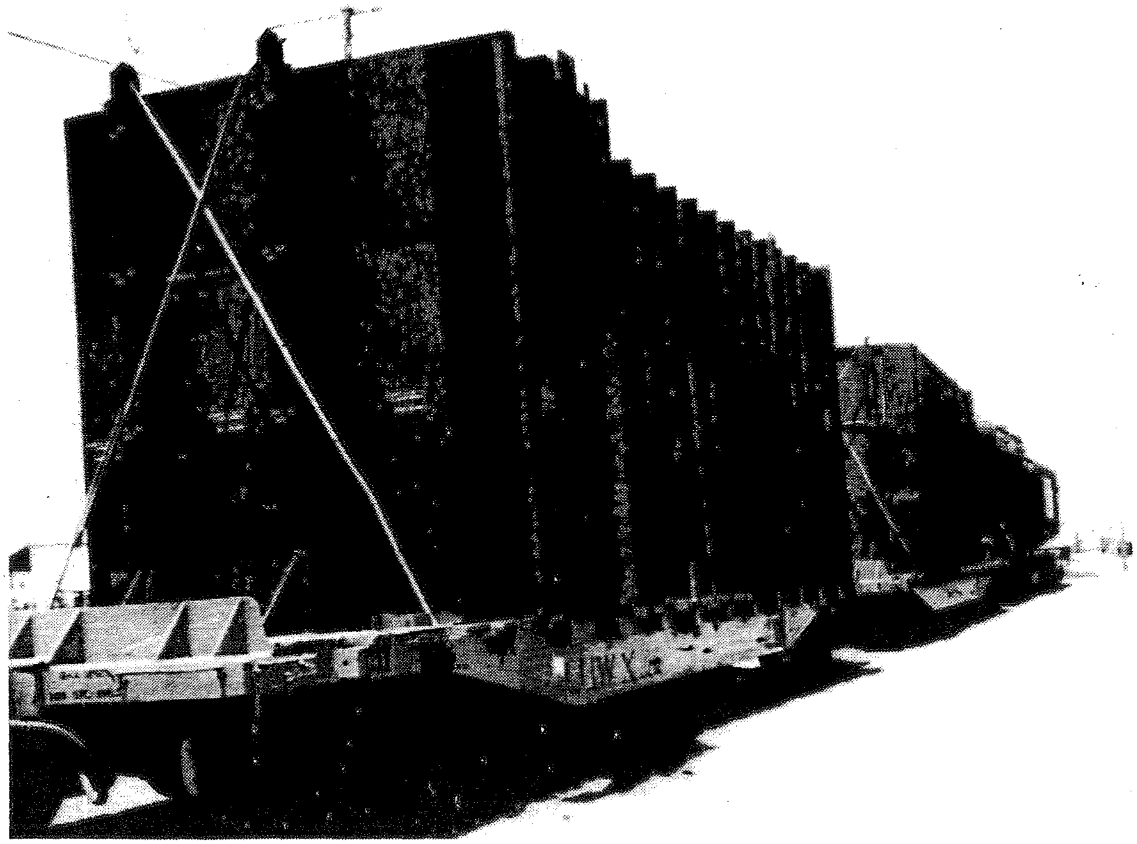

Figure 9 Airheater Modules

Figure 10 Furnace Modules Being Trucked Over Coast Range

The erection of the unit went smoothly. All modules were positioned and joined together in less than a month. Completion of the overall erection took approximately seven months. Georgia-Pacific will complete tie-in of the new fuel delivery equipment with their existing fuel feed system. G-P will also be completing the installation and debugging of combustion controls for this new unit.

Some of the final erection efforts by both parties have been hampered during this winter due to the severe rains this area of California has experienced. Construction scheduling of the back-end equipment was tailored to match the constraints of the existing units and the boiler/furnace modules. Because of the crowded site conditions, foundations for the back-end equipment, i.e. dust collector, ID and FD fans, scrubber and settling tank, were delayed until the modules were placed into position. Once placement of these modules was completed, the back-end equipment area was released for foundation work.

Figures 11 and 12 depict major milestones in unit erection. At the time this paper is being presented, the unit should be operational. Startup was targeted for March 1983 with commercial operation after testing slated for mid-to-late April 1983.

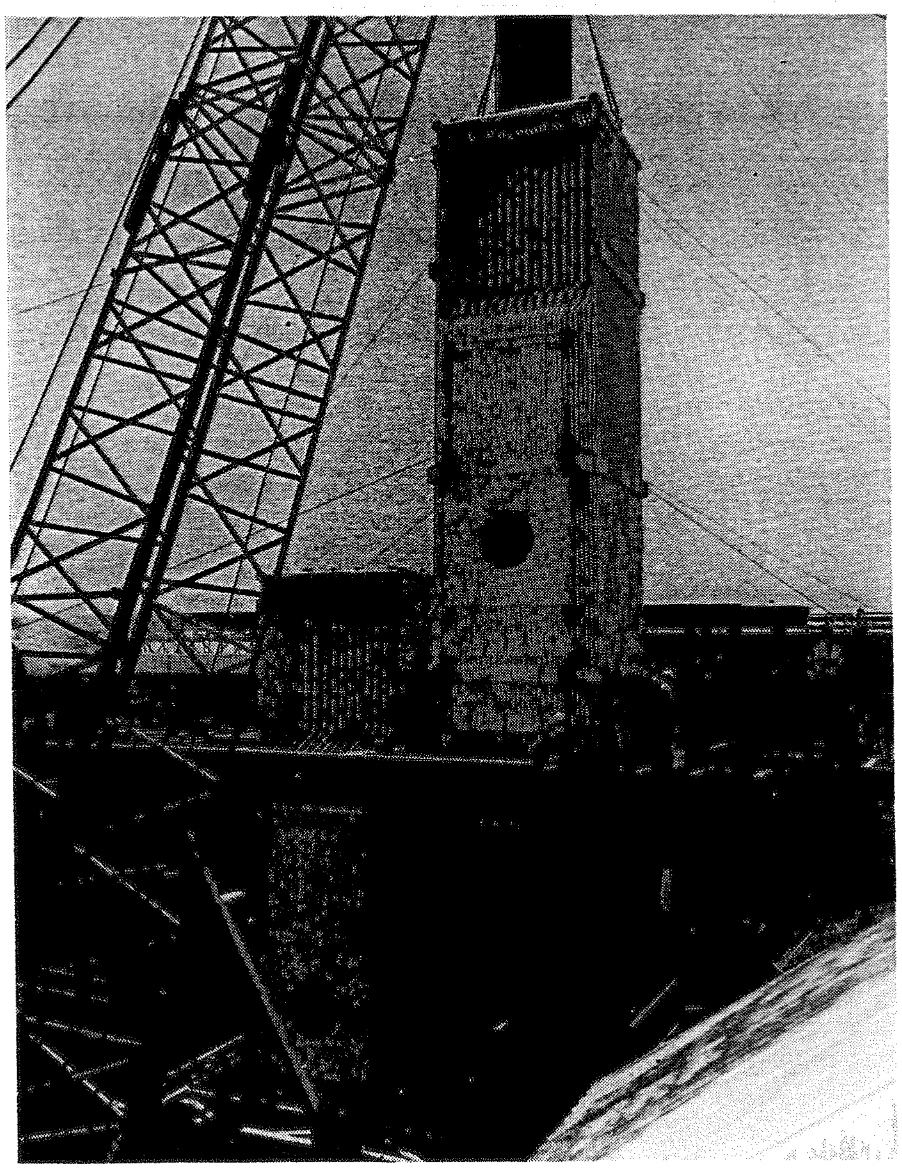

Figure 11 Furnaces Being Lowered Onto Boiler Steel

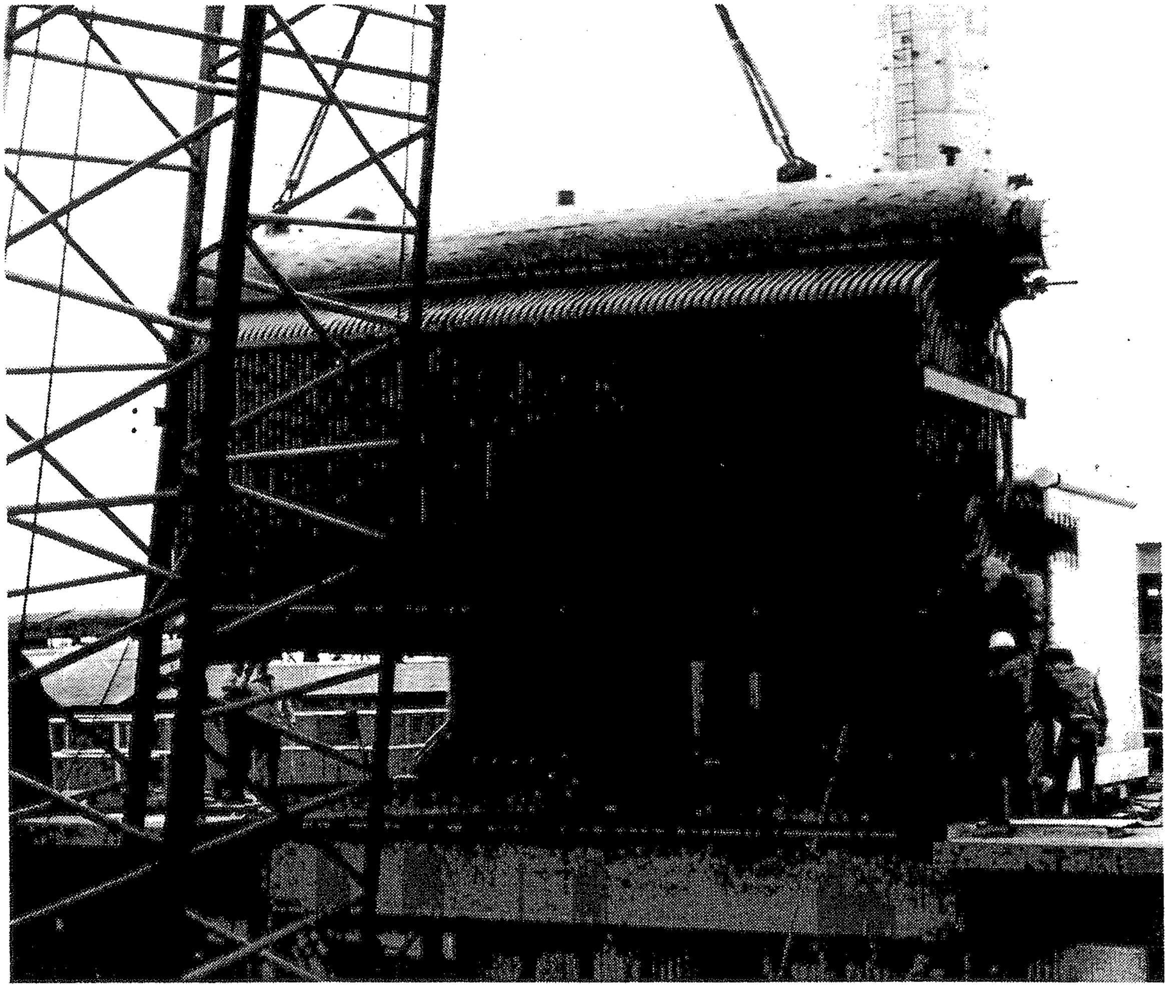

Figure 12 Boiler Module Being Positioned At Jobsite

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2. Castillo, F., "Design Flexibility in a Stoker-Fired Shop Assembled Modular Boiler," American Power Conference, April 26-29, 1982.