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DEVELOPMENT AND TESTING OF A COMMERCIAL SCALE COAL-FIRED COMBUSTION SYSTEM – PHASE III

Final Technical Progress Report
Report Period: September 26, 1990 to August 31, 1994

By
A. Litka and R. Breault

October 1994

Work Performed Under Contract No. DE-AC22-90PC90156
September 26, 1990 to August 31, 1994

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1. INTRODUCTION AND SUMMARY

This report summarizes the results of work performed in the development and testing of a coal-fired space heating system for the commercial market sector. Although coal is the most plentiful energy resource in the United States, its use since World War II has been largely restricted to utility power generation for environmental and economic reasons. Within the commercial sector, oil and natural gas are the predominant heating fuels for office buildings, apartment complexes, and similar structures. Generally, these buildings require firing rates of 1 to 10 million Btu/hr. The objective of this program was to design, build, and test a coal-based heating system for this sector, and determine the economic viability and market potential for the system.

An important consideration for meeting the objectives was the fuel form to be utilized. In attempting to restore coal to relatively small markets, it is important to recognize ease of handling and storage as important criteria. For this reason, coal water slurry (CWS) fuel was chosen as the fuel form for this development effort. CWS eliminates the need to use dry pulverized coal with its attendant handling, metering, and dusting problems, as well as its explosive potential. Equally important in selecting a fuel form is the impact on emission levels and pollution control equipment requirements. CWS is amenable to coal washing, since coal cleaning technologies are generally water-based processes requiring the fine grinding of the coal.

Development and demonstration of the CWS-fired space heating system was carried out over a 42 month period. During the first stage, covering the first 14 months, the program activities focused on component development and system integration. In this stage, an overall system heat balance was prepared, system components were designed and manufactured or purchased, the system was fully assembled, and preliminary testing performed to validate component performance and identify key operating variables.

The second stage covered 10 months and involved proof-of-concept (POC) testing to determine overall performance of the system. The system was operated for prolonged periods to simulate a commercial application, and combustion and thermal efficiencies, tendencies to slag, foul, erode, and corrode, and gaseous and particulate emissions were evaluated. Performance of the system was evaluated using three coals: a low ash, low sulfur eastern Kentucky coal, a moderate ash and sulfur Illinois coal (Illinois No. 5), and a high ash, high sulfur Illinois coal (Illinois No. 6). Also during the second stage, commercial viability of the system was assessed. This assessment included an evaluation of the economics and market potential, including the sensitivity to fluctuations in fuel prices.

The final stage of the program, which covered an 18-month period, consisted of a field demonstration of the technology in an actual commercial market sector installation. Figure 1.1 gives the work breakdown structure for the overall program.

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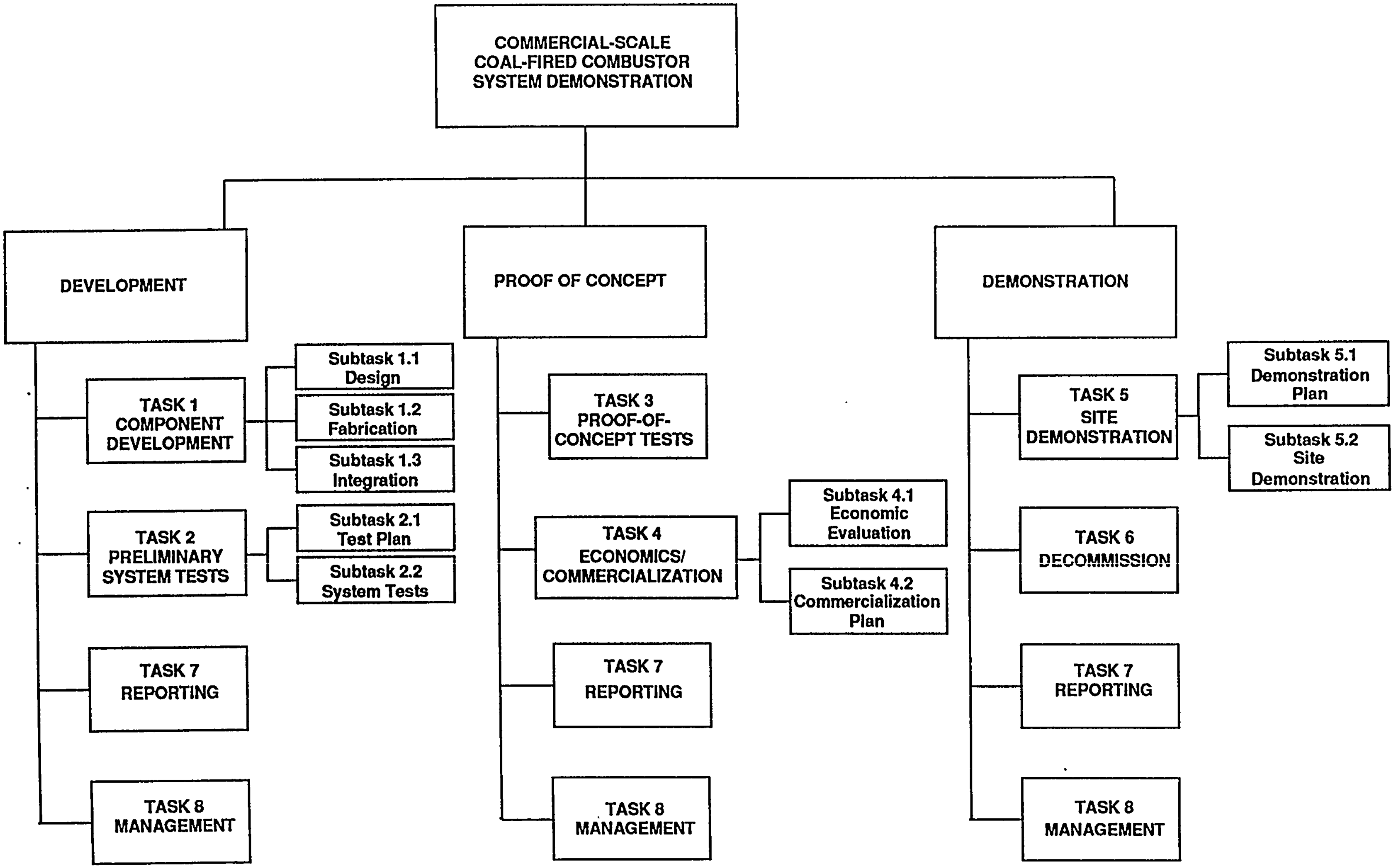

Figure 1.1 Work Breakdown Structure for Entire Project

It was recognized that CWS fuel could not be obtained or widely produced at this time from commercial sources, so a fuel preparation system was also included as part of the demonstration effort. To ensure a supply of CWS for the program and also to demonstrate that CWS can be economically produced, a slurry preparation facility was set up and used to supply CWS fuel for the program. It is recognized that to get CWS fuel into the commercial scale marketplace, it will take a combined effort to develop both the combustion equipment and fuel supply simultaneously.

A brief description of the overall system design is given in this report, as well as a discussion of the unique features of the system configuration and key components. This is followed by a summary of the testing performed, including a comparison between system performance and program goals. Finally, the results of the economic evaluation are presented, along with a commercialization plan for the technology. A key issue in the eventual commercialization of the technology is the availability of a competitively priced coal water slurry fuel. Predicted prices and availability of CWS are discussed.

In summary, a fully operational prototype system was designed, built, and successfully tested. As part of the system development, the CWS combustor technology was scaled from a previously developed residential size to the commercial market size, integration of the combustor technology with a conventional firetube boiler was demonstrated, and a highly efficient, low wear slurry atomizer was developed. Laboratory and demonstration site operation has shown the ability to meet system performance goals utilizing three coals of varying quality, including high sulfur, high ash Illinois No. 6 coal. Over the course of the development program, the system was operated for over 1300 hours, consuming over 30,000 gallons of slurry, demonstrating both its reliability and flexibility of operation. With all three coals, emissions met program goals and were below anticipated Clean Air Act levels. Operation requirements of system turndown, automatic startup, and trouble-free operation were also demonstrated.

The economic and market evaluation revealed that, at moderate differentials between premium fuel and coal water slurry fuel prices, such a system can be economically attractive with short payback periods and substantial life cycle savings. With predicted escalation in premium fuel prices and readily available CWS, the system has the potential of competing with premium fuel systems, and until that time, will be available to satisfy niche markets where fuel is readily available and inexpensive, such as locations near coal mines where coal fines in the form of slurry is now considered a waste product.

2. SYSTEM DESIGN

2.1 SYSTEM CONFIGURATION

A process schematic for the CWS-fired space heating system is shown in Figure 2.1. The system was designed for a nominal firing rate of 4 million Btu/hr, approximately the mid-range of the commercial scale market sector. The system was configured so that commercially available equipment and technologies were utilized wherever practical. In particular, a firetube boiler typically found in installations of the commercial sector size range was used for primary heat extraction. Since only moderate changes are required to the boiler itself, the technology can be utilized to convert existing oil and natural gas systems to coal firing.

In the following sections, the design and unique features of the major system components are described. Particular emphasis is placed on those components and subsystems specifically developed for a coal- or CWS-fired system.

2.2 COMPONENT DESIGN

2.2.1 Combustor

One piece of equipment that is not commercially available is the combustor itself. The commercial scale space heating system combustor is a scale-up of a combustor technology developed by Tecogen under contract to the Department of Energy (DOE), Pittsburgh Energy Technology Center, for the residential scale market sector.

The combustor concept (see Figure 2.2) employs centrifugal forces combined with a staged combustion process to achieve high carbon conversion efficiencies and low nitrogen oxides (NO_x) emissions. The combustion chamber is divided into multiple zones by partitions to retard the axial flow of unburned coal particles over a given size. In this fashion, the residence time for combustion of the CWS fuel is significantly increased to enable complete carbon conversion for a wide range of particle droplet sizes. Once the particles are small enough to pass through all the partitions, they enter a secondary combustion chamber where burnout of any remaining char is completed.

The residential combustor developed previously had a nominal firing rate of 150,000 Btu/hr, therefore a scale-up of approximately 25 was required to meet the design firing rate of 4 million Btu/hr for the commercial scale system. Scaling laws which take into account the fluid dynamics and chemical kinetics in the combustor were developed to extend the knowledge base that had been established on the residential unit.

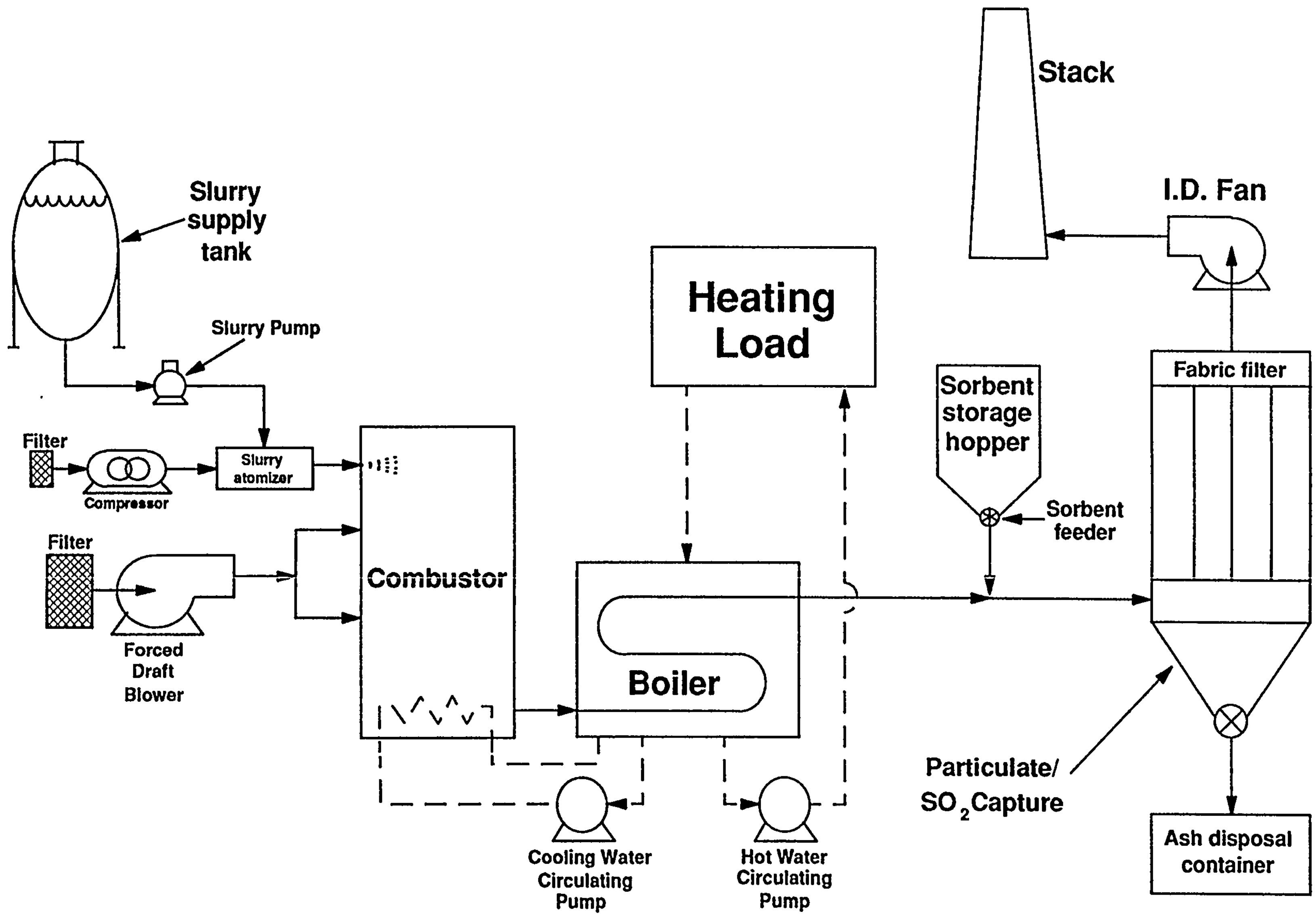

Figure 2.1 Process Flow Diagram

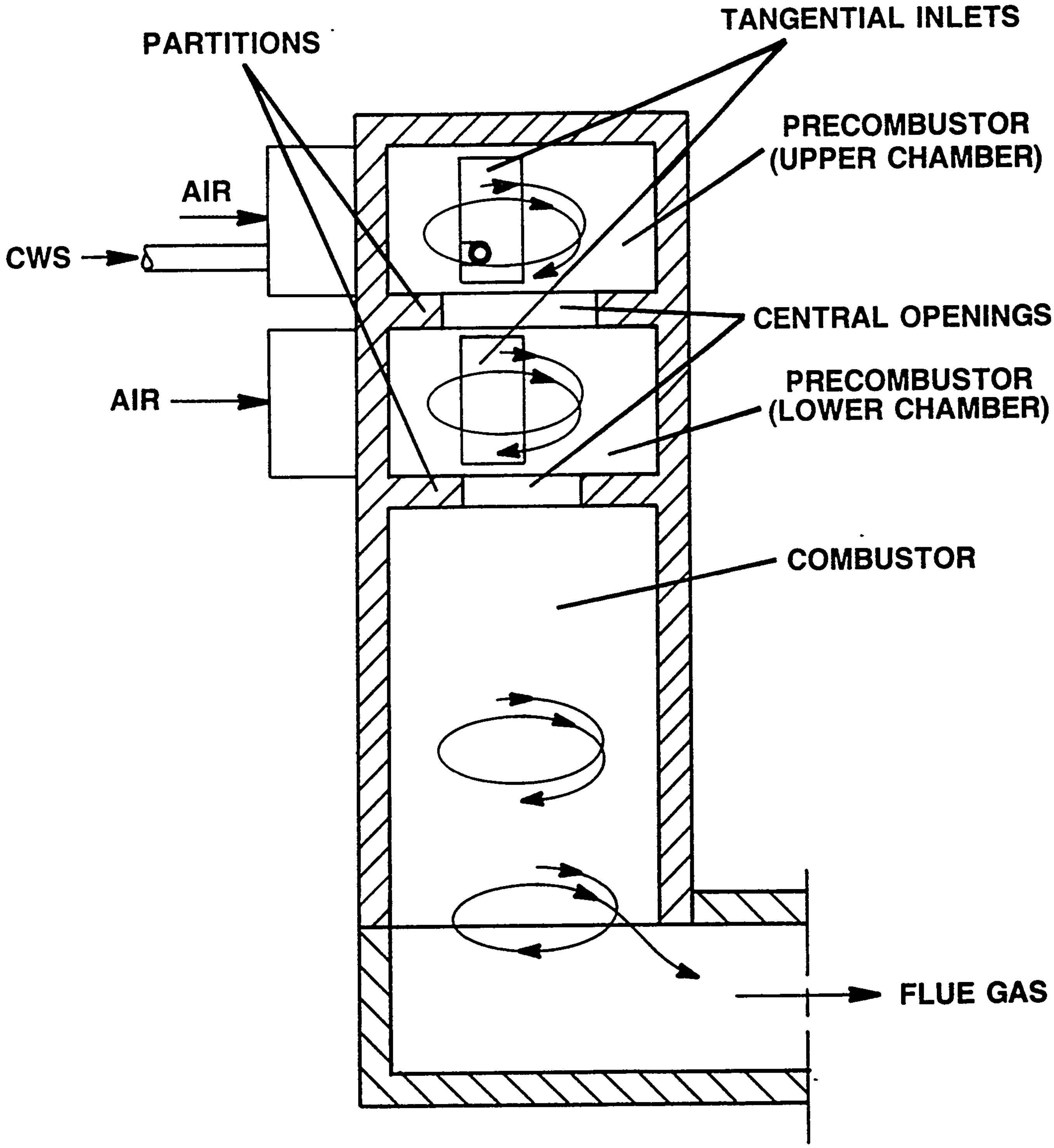

Figure 2.2 Combustor Principle of Operation

- <u>Scaling Law Principles</u>

In developing the scaling laws for the combustor, one of the key factors that must be taken into account is particle separation efficiency. If a larger combustor is capable of capturing the same size particles as the residential unit, then, with all other factors the same, comparable performance can be expected. In order to determine the theoretical particle size that can be detained within the combustor, a balance between centrifugal forces and drag forces at the radial location that coincides with the edge of the lower partition was conducted. This results in a relationship for particle diameter that is a function of the tangential and radial velocities fields within the combustor, as shown in equation 1:

$$D_p = \left(\frac{18\ \mu\ V_{gr}\ r_{out}}{\rho_p\ V_t^2} \right)^{\frac{1}{2}} \tag{1}$$

where:

V_{gr} is the radial gas velocity
V_t is the tangential gas velocity
μ is the gas viscosity
ρ_p is the particle density
r_{out} is the radial position of the edge of the lower partition

The tangential velocity in a vortical flow field can be described by:

$$V_t = V_{in}\ (1-n)^{\frac{1}{2}} \left[\frac{r_o}{r} - n \left(\frac{r_o}{r} - \frac{r}{r_o} \right) \right] \tag{2}$$

where:

V_{in} is the inlet velocity
n is a constant between 0 and 1
r_o is the radius of the combustor wall

Based on experimental data, Smolensky[1] found that n was related to the inlet area and the combustor radius by the following relationship:

$$n = 1 - 1.4 \left(\frac{\sqrt{A_{inlet}}}{r_o} \right)^{0.9} \tag{3}$$

In order to determine the radial velocity at the lower partition, it was assumed that the flow could be modeled as a point sink positioned at the combustor centerline:

$$V_g = \frac{\dot{m}}{2 \pi \rho_g} \left(\frac{1}{r^2} - \frac{r}{r_o^3} \right) \tag{4}$$

When these relationships are substituted into equation 1, the following expression for particle diameter can be written:

$$D_p = \left[\frac{\left(\frac{18 \mu}{\pi} \right) \left(\frac{\rho_g}{\rho_p} \right) m \left(1 - D^{*3} \right)}{D^* \, D_o \, \rho_{g_n}^2 \, V_{in}^2 \, (1 - n) \left[\frac{1}{D^*} - n \left(\frac{1}{D^*} - D^* \right) \right]^2} \right]^{\frac{1}{2}} \tag{5}$$

where:

m. is the mass flow rate

D^* is the ratio of the lower partition diameter to the combustor diameter

The particle diameter predicted by equation 5 must be viewed as a theoretical diameter that the combustor can detain, as opposed to an absolute value. This is due to the high degree of turbulence present in the combustor. Since turbulent fluctuations can be greater than the radial velocity predicted by equation 4, it is more appropriate to normalize D_p for the commercial combustor with that of the residential combustor. When this normalized particle diameter ratio is less than one, then the commercial combustor is capable of separating particles smaller than the residential combustor.

With a knowledge of the factors that effect the separation efficiency of the commercial combustor, it should be quite easy to design a unit capable of separating particles equal in diameter to that of the residential combustor. The problem that accompanies this approach is the allowable pressure drop with which the commercial combustor can operate. The commercial combustor operates at a much higher mass flow rate than does the residential unit, and, as such, equation 5 indicates a decrease in its ability to capture smaller particles. In order to be able to capture the same size particle as the residential unit, the inlet velocity must increase. This can lead to a substantial increase in pressure drop unless the value of D^* is adjusted accordingly.

The pressure drop for a vortical flow device such as the CWS combustor, was found from experimental investigations to be a function of inlet velocity, D^*, and n. Smolensky[1] determined this relationship to be:

$$\Delta p = \frac{\rho\, V_{in}^2}{2} (1 - n') \left[n^2 (1 - 0.36\ D*^2) + (1 - n')^2 \left(2.78 \left(\frac{1}{D*} \right)^2 - 1 \right) + n' (1 - n') \ln \left(\frac{1.67}{D*} \right) \right] \tag{6}$$

where n′ is the value "n" multiplied by 1.1 to best fit the data.

Using equations 5 and 6, both normalized to residential combustor operating conditions, a direct comparison of the effects of inlet velocity and combustor geometric ratios on particle capture diameter and pressure drop can be established for design purposes. Figures 2.3 through 2.6 provide a graphical representation of the results for two different combustor diameters, 24 and 36 inches, plotting particle diameter ratio (Dp com/ Dp res), and pressure drop ratio versus inlet velocity ratio.

In addition to having the ability to capture particles of a comparable size to that of the residential combustor, the commercial combustor must have comparable gas phase residence times in both the primary and secondary zones to ensure comparable combustion efficiencies, as well as NO_x emission levels. The effect of residence time becomes apparent in the height of the combustion chambers. In order to maintain residence time similitude, for the 24 and 36 inch diameter units, combustor heights of 98 and 44 inches, respectively, are required.

The assumption that the commercial combustor must have the same gas phase residence time, as well as the ability to capture particles the same diameter as the residential combustor, is quite conservative. This is due to the fact that the commercial combustor should operate at a higher temperature than the residential unit. The residential combustor has a surface area to volume ratio of about 6 ft^2/ft^3, compared to less than 2 ft^2/ft^3 in the commercial combustor. The lower relative surface area for heat transfer in the commercial scale combustor translates to higher average gas temperatures. The higher temperatures associated with the commercial combustor increase the chemical reaction rates, and, as such, in order to achieve the same combustion efficiency, the commercial combustor does not need to be able to capture particles of the same size as those in the residential scale combustor.

To obtain a quantitative feel for the effect of combustor operating temperature on particle diameter, consider a general heterogenous reaction to dominate the overall reaction scheme:

$$A_{gas} + bB_{solid} \xrightarrow{k} \text{products} \tag{7}$$

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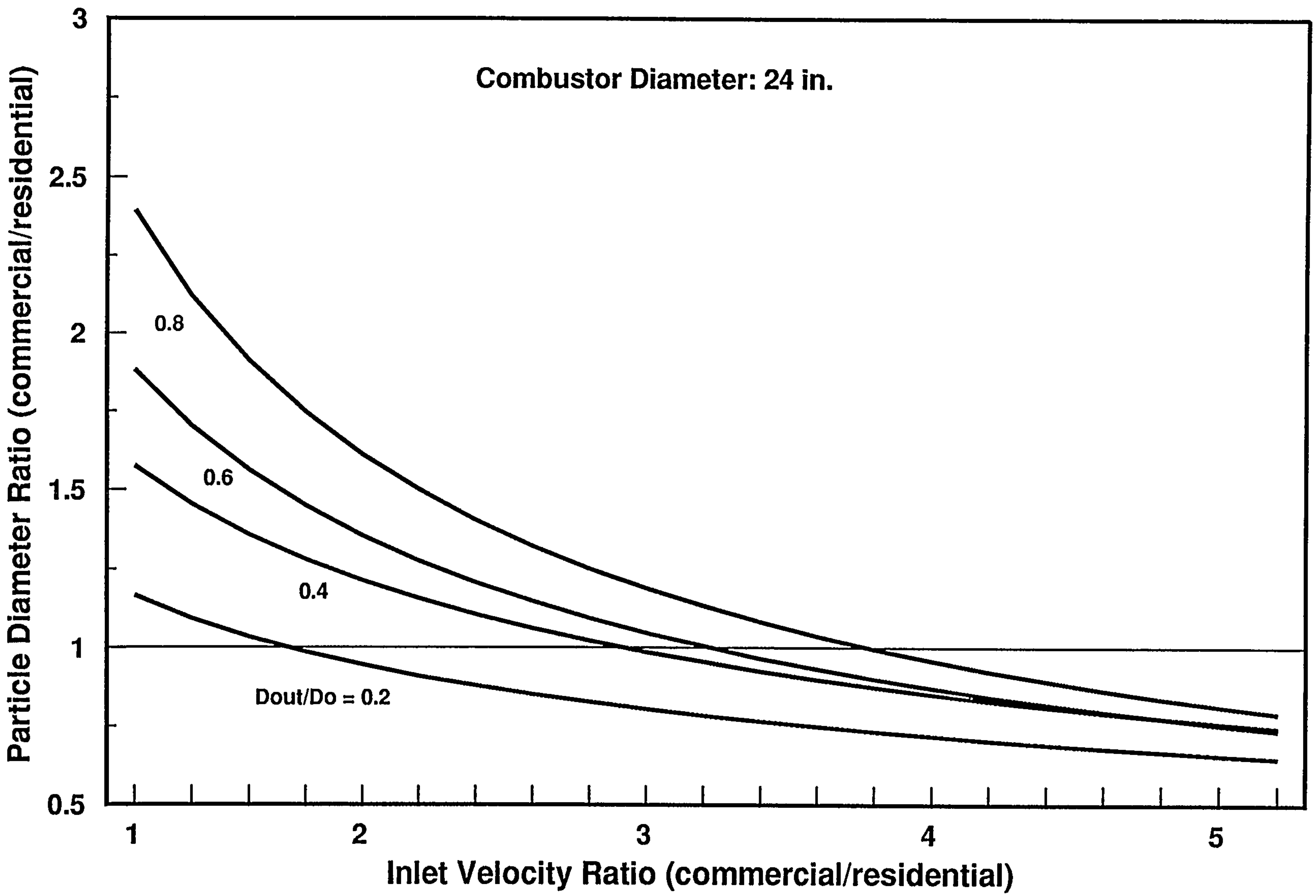

Figure 2.3 Particle Diameter Ratio vs. Inlet Velocity Ratio, 24-Inch Combustor (Dout/Do = Partition Diameter/Combustor Diameter)

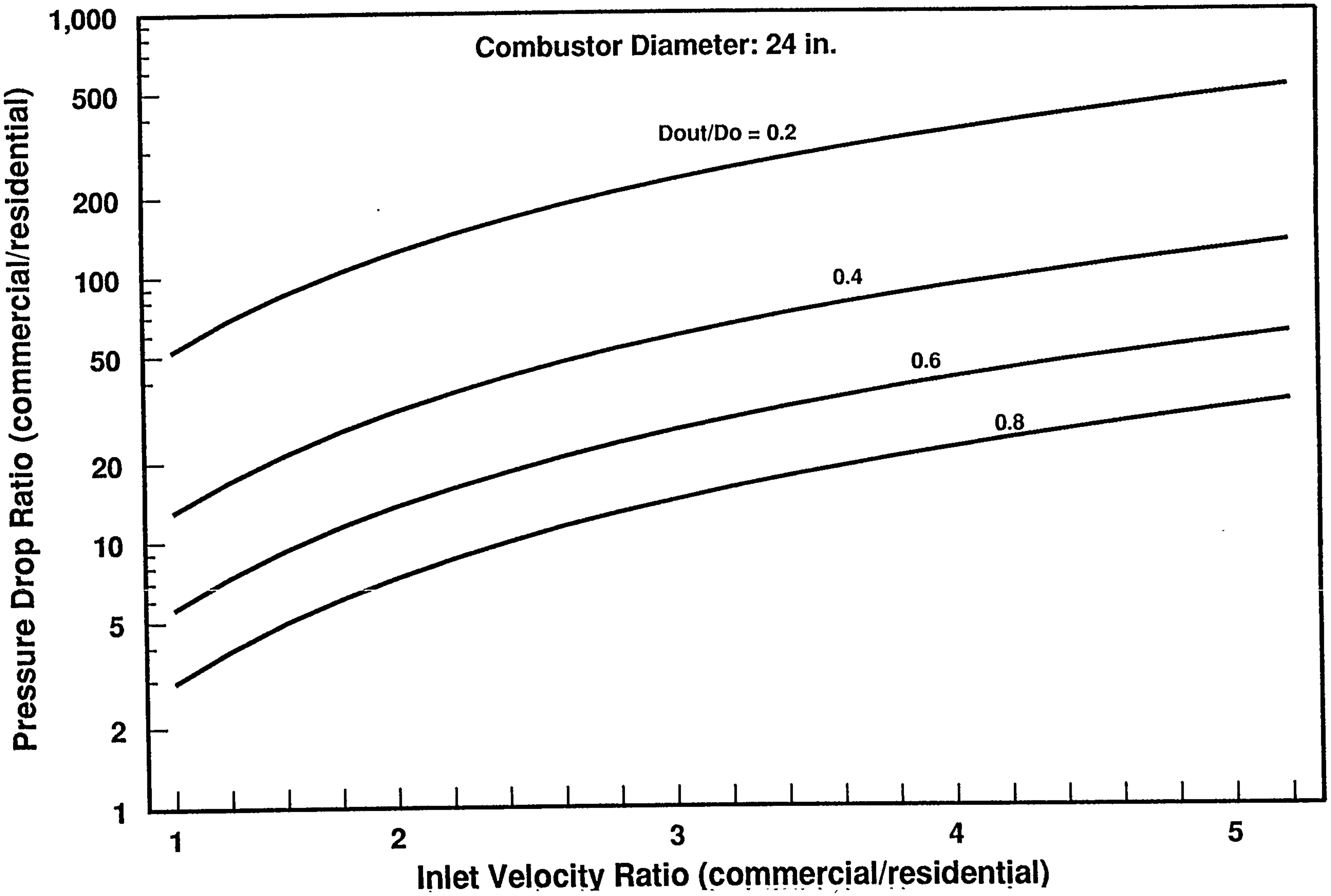

Figure 2.4 Pressure Drop Ratio vs. Inlet Velocity Ratio, 24-Inch Combustor (Dout/Do = Partition Diameter/Combustor Diameter)

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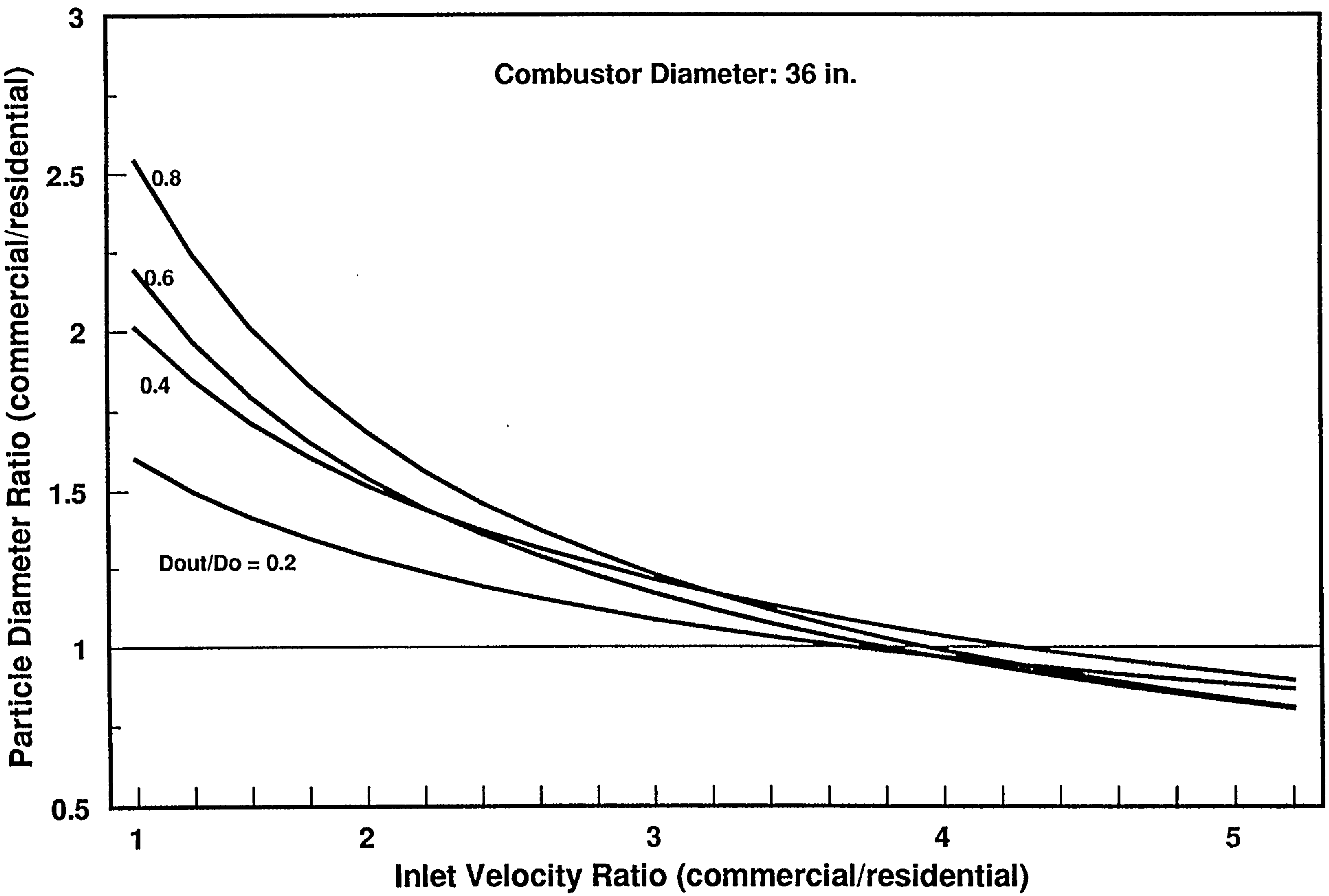

Figure 2.5 Particle Diameter Ratio vs. Inlet Velocity Ratio, 36-Inch Combustor (Dout/Do = Partition Diameter/Combustor Diameter)

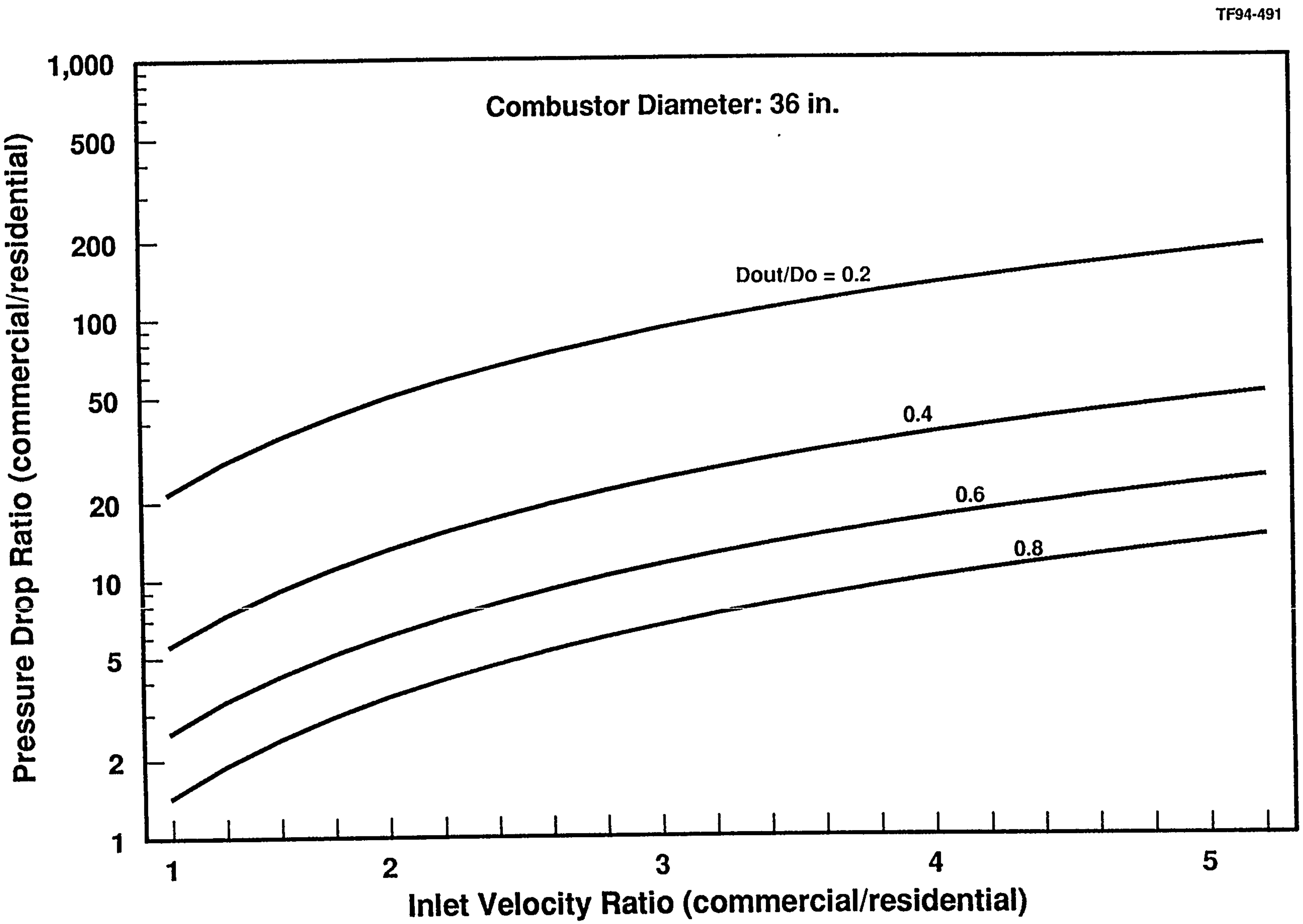

Figure 2.6 Pressure Drop Ratio vs. Inlet Velocity Ratio, 36-Inch Combustor (Dout/Do = Partition Diameter/Combustor Diameter)

If we assume this reaction to be first order:

$$\frac{dm_B}{d\,t} = \frac{-\,A\;b\;M_B\;C_A}{\dfrac{1}{k_c} + \dfrac{1}{k_d}} \tag{8}$$

where:

- A is the particle surface area
- b is the stoichiometric coefficient
- M_b is the molecular weight of species B
- C_A is the concentration of species
- k_c resistance due to chemical kinetics
- k_d resistance due to diffusion

For the small particles being considered, it is assumed that diffusion is negligible. Further, if the reaction rate constant can be expressed as an Arrhenius relationship, then the effect of the elevated temperatures associated with the commercial combustor relative to the residential combustor can be evaluated. By introducing the Arrhenius assumption, and normalizing the reaction rate expression with that of the residential combustor, a reaction rate parameter can be defined as:

$$\Gamma = \left(\frac{D_{p_{res}}}{D_{p_{com}}}\right) \frac{\exp\left(\dfrac{-\,ET*}{R\;T_{res}}\right)}{\exp\left(\dfrac{-\,E}{R\;T_{res}}\right)} \tag{9}$$

where:

- E is the activation energy
- R is the universal gas constant
- T_{res} is the average temperature at which the residential combustor operates
- T^* is the absolute temperature ratio (residential/commercial)

If char oxidation is assumed to be the dominate reaction, then, by using an activation energy of 21,900 kcal/kg-mole, typical of bituminous coals, a plot of the reaction rate parameter can be made as a function of absolute temperature ratio and particle diameter ratio, as shown in Figure 2.7. The meaning of the reaction rate parameter is as follows: when this parameter is equal to one, the same degree of char oxidation should occur in both the commercial and residential combustors; when this parameter is greater than one, reaction rates favor the commercial combustor; when this parameter is less than one, the kinetics occurring in the residential combustor are favored.

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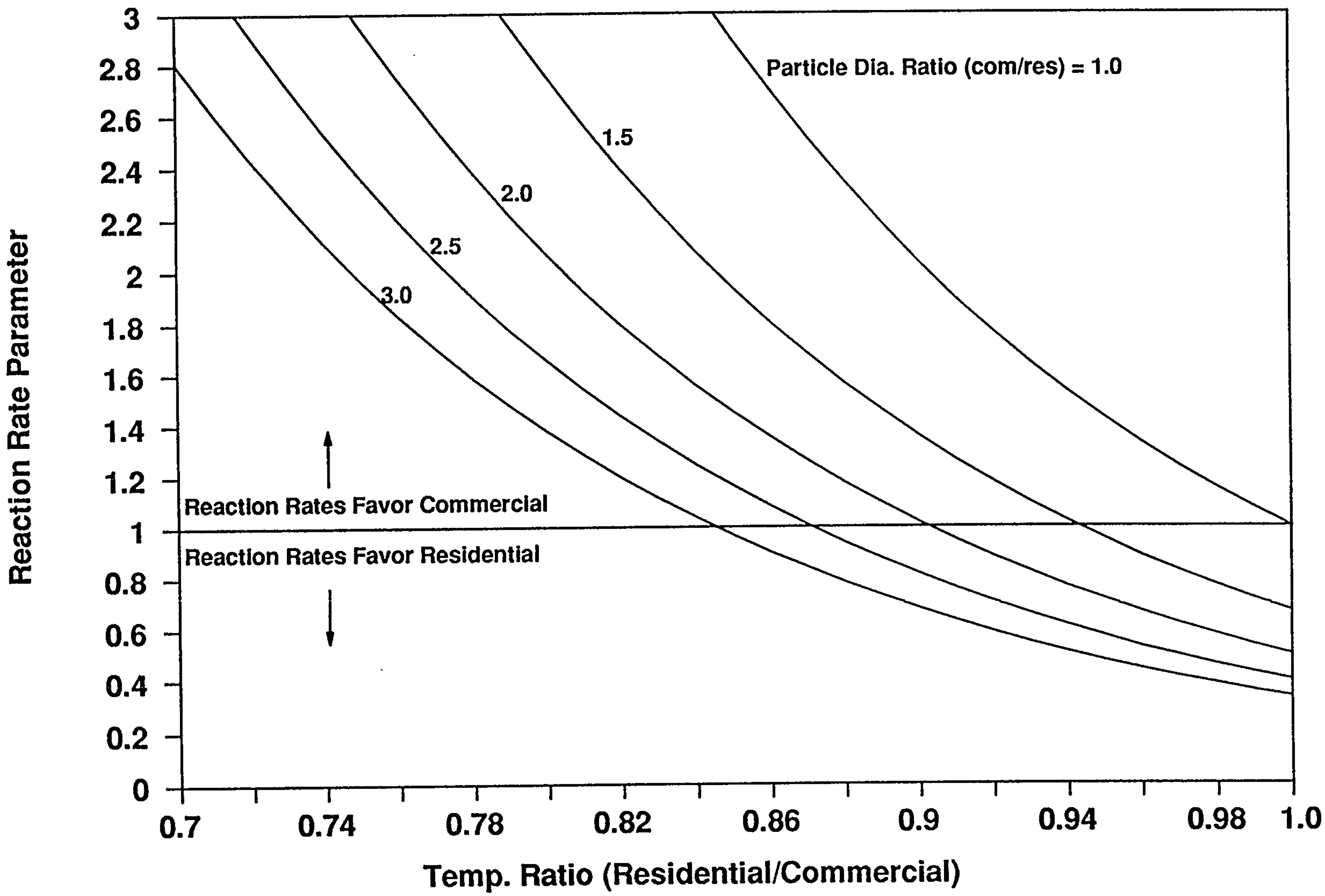


Figure 2.7 Reaction Rate Parameter vs. Temperature Ratio

- Combustor Configuration

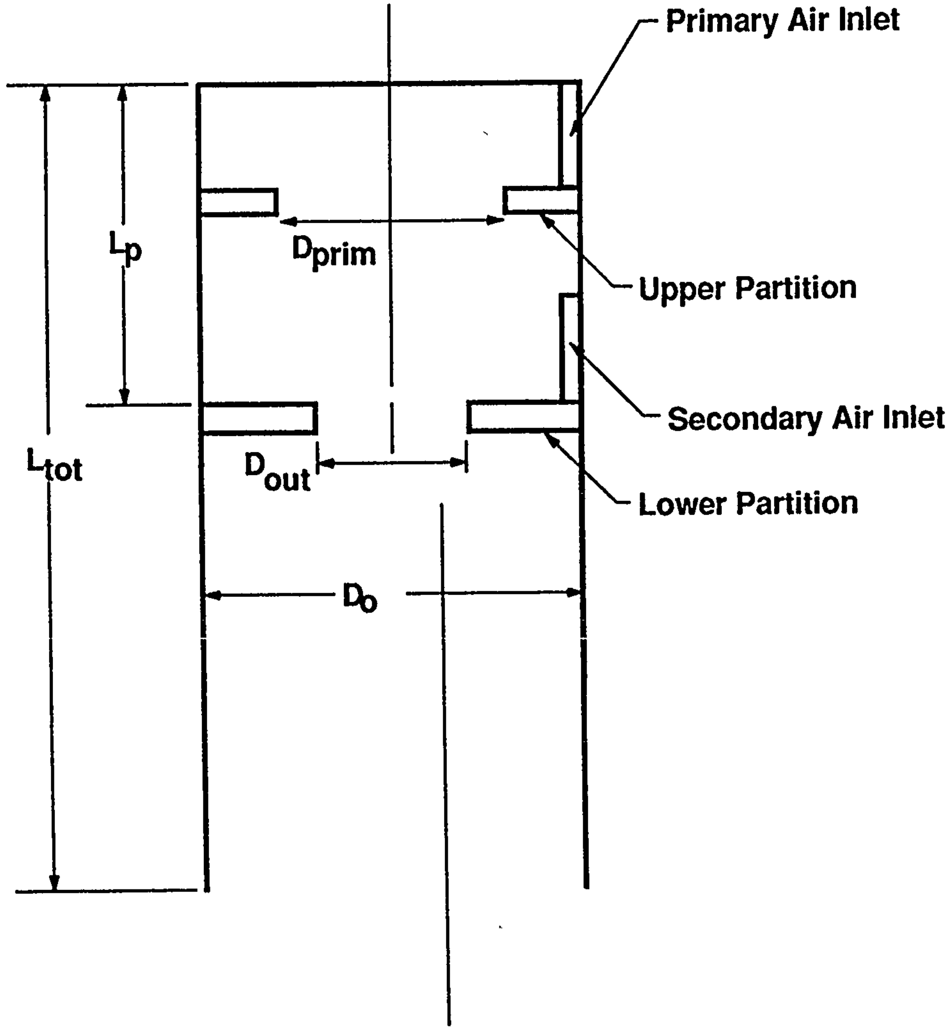
Based on the above scaling laws, a combustor diameter for the commercial scale unit of 24" was determined to provide good scaling with respect to the overall combustor configuration and predicted operating conditions. The corresponding overall combustor length is 60". Figure 2.8 gives the results of the scale-up analysis and a comparison to the residential unit. Inlet areas are sized for an inlet velocity of 150 ft/sec.

Figure 2.9 is a photograph of the combustor assembly. The combustor is made up of three sections: a roof, an upper section, and a lower section. Each section is a double-jacketed water-cooled unit. In this photograph, the combustor is connected to an exhaust quench system, which is a configuration used for initial combustor shakedown and characterization. During the course of the development program, several modifications to the combustor's internal configuration were made to improve operating performance. These changes involved replacing refractory surfaces with metal liners to reduce material accumulation in the combustor, changing the size and location of partitions and varying the air inlet geometries. These changes are discussed in detail in Section 4, as part of a discussion of the test results.

The combustor is connected to the firetube heat recovery boiler through a transition chamber. The transition chamber turns the vertical downward-flowing combustion gases and directs them to the horizontal firetube of the boiler. In addition, the transition serves as a collection vessel for large ash agglomerates which may form in the combustor. The transition chamber is also a double-jacketed water-cooled unit, and has 3" of refractory to control the heat extraction from the unit. Figure 2.10 shows the combustor/transition chamber assembly, and Figure 2.11 shows the connection to the firetube interface. A high temperature expansion joint is used to connect the transition chamber outlet with the boiler inlet to allow for alignment flexibility and differential thermal growth of the two assemblies. This arrangement does not require any modification to the inlet of the conventional firetube boiler, and therefore, the combustor can be easily retrofitted into existing oil and gas-fired installations.

2.2.2 Boiler

A conventional firetube boiler is used to recover the heat from the combustion gases leaving the transition chamber. To achieve the system performance goal of greater than 80% thermal efficiency, a three-pass configuration was selected. A schematic representation of the boiler configuration is shown in Figure 2.12. A 400-ft^2 boiler, having a drum diameter of 4.5 ft and an overall length of 11 ft, was chosen. Table 2.1 gives the predicted operating conditions for the boiler at various gas inlet temperatures and flowrates. Boiler water is utilized as cooling water for the combustor and transition chamber. A dedicated circulating pump is provided for this purpose.



RESIDENTIAL COMBUSTOR

Thermal Input	150,000 Btu/hr
D_o	8.5 in.
D_{prim}	5.8 in.
D_{out}	4.0 in.
L_p	15.0 in.
L_{tot}	30.0 in.
Air Inlet	
Primary	0.25 in.^{2}
Secondary	0.56 in.^{2}

COMMERCIAL COMBUSTOR

Thermal Input	4 X 10^6Btu/hr
D_o	24 in.
D_{prim}	16 in.
D_{out}	12 in.
L_p	40 in.
L_{tot}	60 in.
Air Inlet	
Primary	4.8 in.^{2}
Secondary	4.8 in.^{2}

Figure 2.8 Combustor Scaled From Residential Size

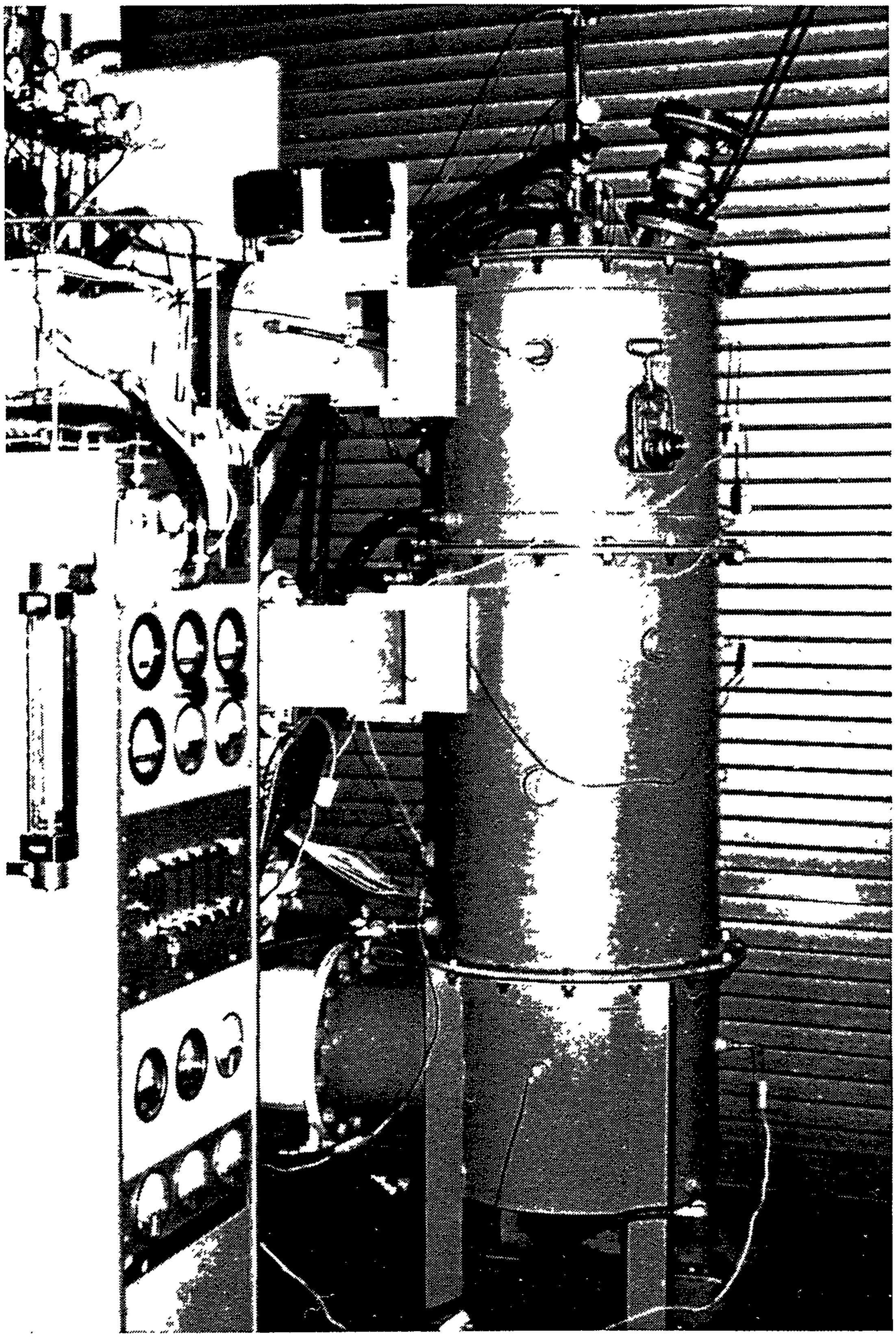


Figure 2.9 Photograph of the Test Setup

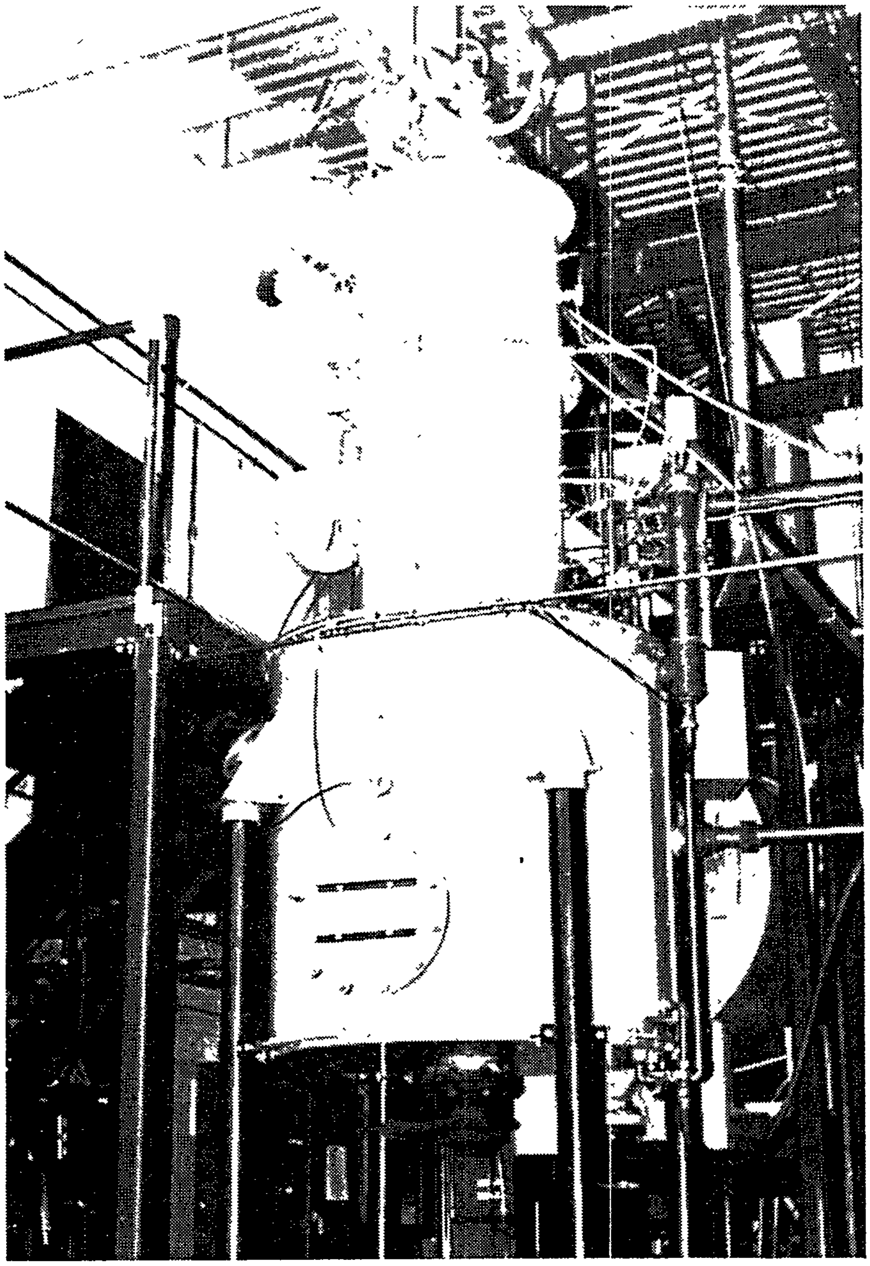


Figure 2.10 Combustor/Transition Chamber Assembly

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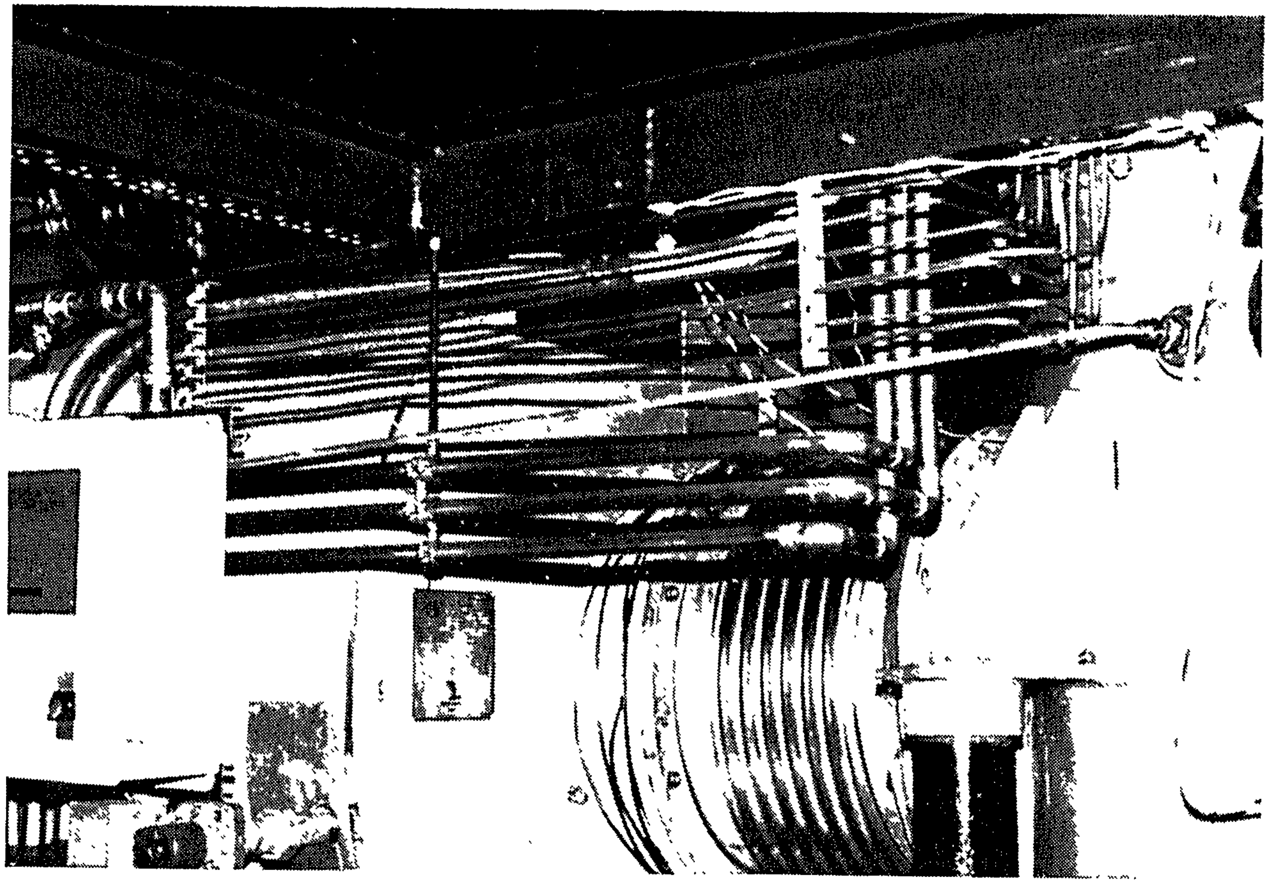

Figure 2.11 Combustor/Transition Chamber Interface

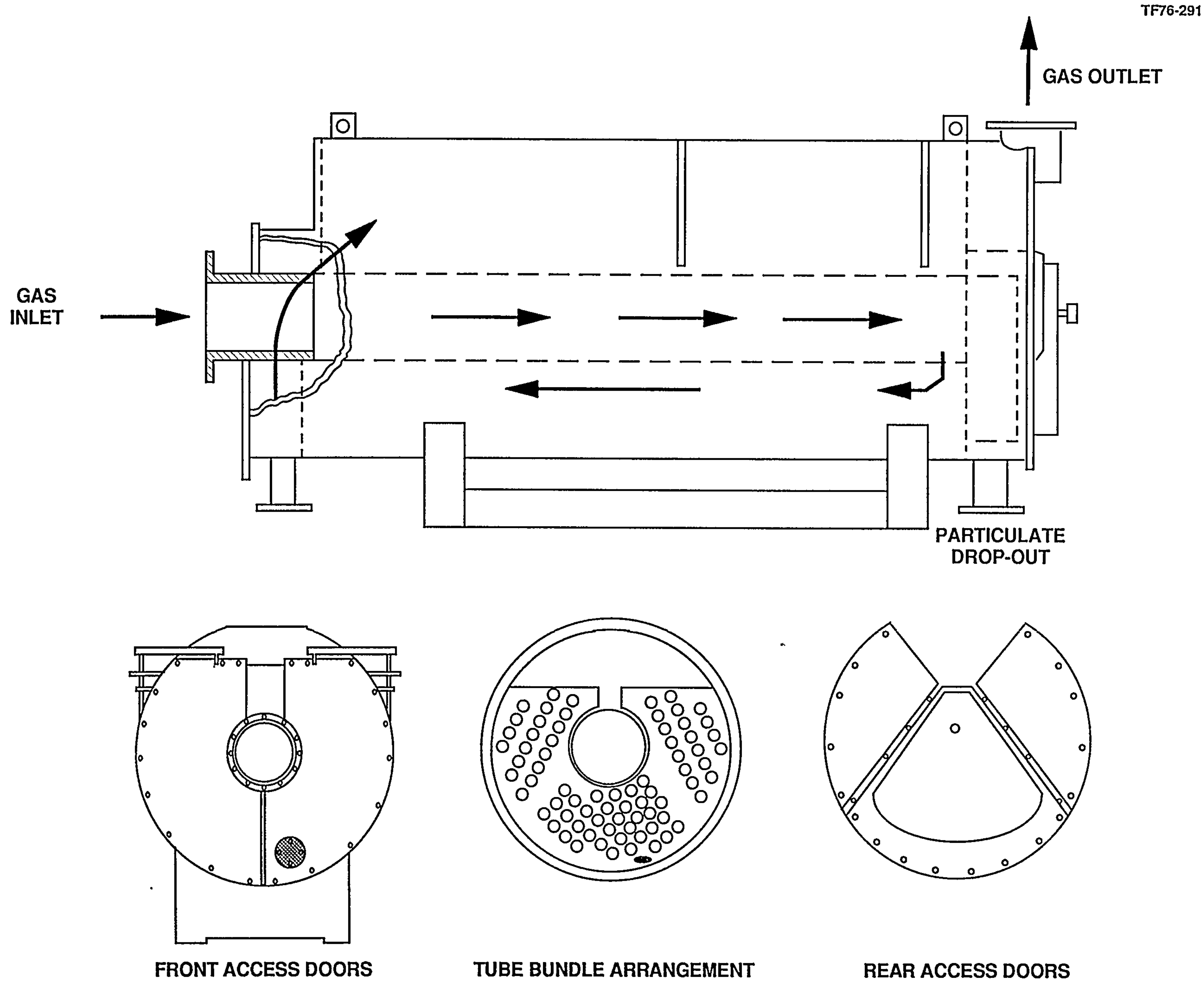

Figure 2.12 Firetube Heat-Recovery Boiler Configuration

TABLE 2.1

PERFORMANCE DATA FOR 400-FT^2 HOT WATER BOILER

Description	Case I			Case II			Case III		
Flue Gas Flow (lb/hr)	4225	2817	1408	4225	2817	1408	4225	2817	1408
Flue Gas Inlet Temp. (^oF)	2000	2000	2000	2300	2300	2300	2600	2600	2600
I Pass Outlet Temp. (^oF)	1754	1704	1582	1977	1903	1728	2187	2087	1848
II Pass Outlet Temp. (^oF)	608	554	458	655	587	479	699	619	496
III Pass Outlet Temp. (^oF)	321.5	294	252	336	303	257	349.6	312	261
1 Pass Inlet Velocity (ft/s)	32.8	21.8	10.94	36.81	24.5	12.27	40.81	27.2	13.6
2 Pass Inlet Velocity (ft/s)	78.4	51.1	24.1	86.2	55.8	25.82	93.69	60.1	27.23
3 Pass Inlet Velocity (ft/s)	51.2	32.37	14.65	53.4	33.43	14.99	55.5	34.45	15.25
Pressure Drop (in. w.c.)	3.33	1.47	0.36	3.38	1.49	0.36	3.43	1.5	0.37

The only changes made to the manufacturer's standard hot water oil and natural gas-fired configuration was the addition of particulate drop-out hoppers at each end of the boiler, additional connections for combustor cooling water supply and return, and a compressed air soot blowing system. The boiler was initially operated without the soot blowing system, but preliminary testing revealed an increase in boiler exhaust temperature with time due to ash deposition on the boiler heat transfer surfaces. The soot blower system, as shown in Figure 2.13, consists of a nozzle in front of each boiler tube. The nozzles are connected to one of four compressed air manifolds, each controlled by a solenoid valve. Figure 2.14 is a photograph of the soot blowing system's external piping and control cabinet. The system is energized whenever CWS is being fired, and operates with sequential pulsing of the four air manifolds every 15 minutes, for a one hour cycle time. Discussion of the soot blowing system performance as related to overall system thermal efficiency can be found in Section 4. All changes made to the manufacturer's standard boiler can be made in the field on existing oil and natural gas-fired units.

2.2.3 Fuel Delivery System

Although the use of CWS for the commercial market sector greatly simplifies the fuel delivery system as compared to a dry, pulverized coal system, special attention must be placed on the proper design of the system to ensure proper operation of the combustor. Slurry velocities must be sufficiently high to avoid settling, piping dead-ends must be avoided, and proper flushing must be provided to clear the system during prolonged inactivity.

Figure 2.15 is a flow schematic of the fuel delivery system. A key component of the system is the atomizer. The atomizer not only defines the requirements for the handling system, i.e. required slurry pressure and filtration, but also plays a key role in the efficiency and stability of the combustion process. A variable spray angle, externally mixed twin fluid atomizer was developed to meet the needs of the system. This atomizer design is an extension of the twin fluid CWS atomizer technology developed by Tecogen under the previously funded CWS-Fired Residential Warm Air Heating System Program. The atomizer operating conditions can be set to provide the wide cone angle required of the radial, top center firing configuration of the commercial scale system. This atomizer uses two perpendicular atomizing streams to shear the CWS into a thin, unstable ligament sheet that breaks up into small droplets external to the atomizer. Figure 2.16 is a schematic depicting the atomizer arrangement.

The external atomization feature of this nozzle prevents erosion, and allows for a large CWS passageway which minimizes the head that the CWS pump must produce. In addition to providing fine atomization due to the high shear that is imparted by the two perpendicular atomizing streams, by varying the flow rate of each of these streams, the spray angle can be changed on-line without any mechanical modifications to the atomizer. Table 2.2 lists the features of the atomizer.

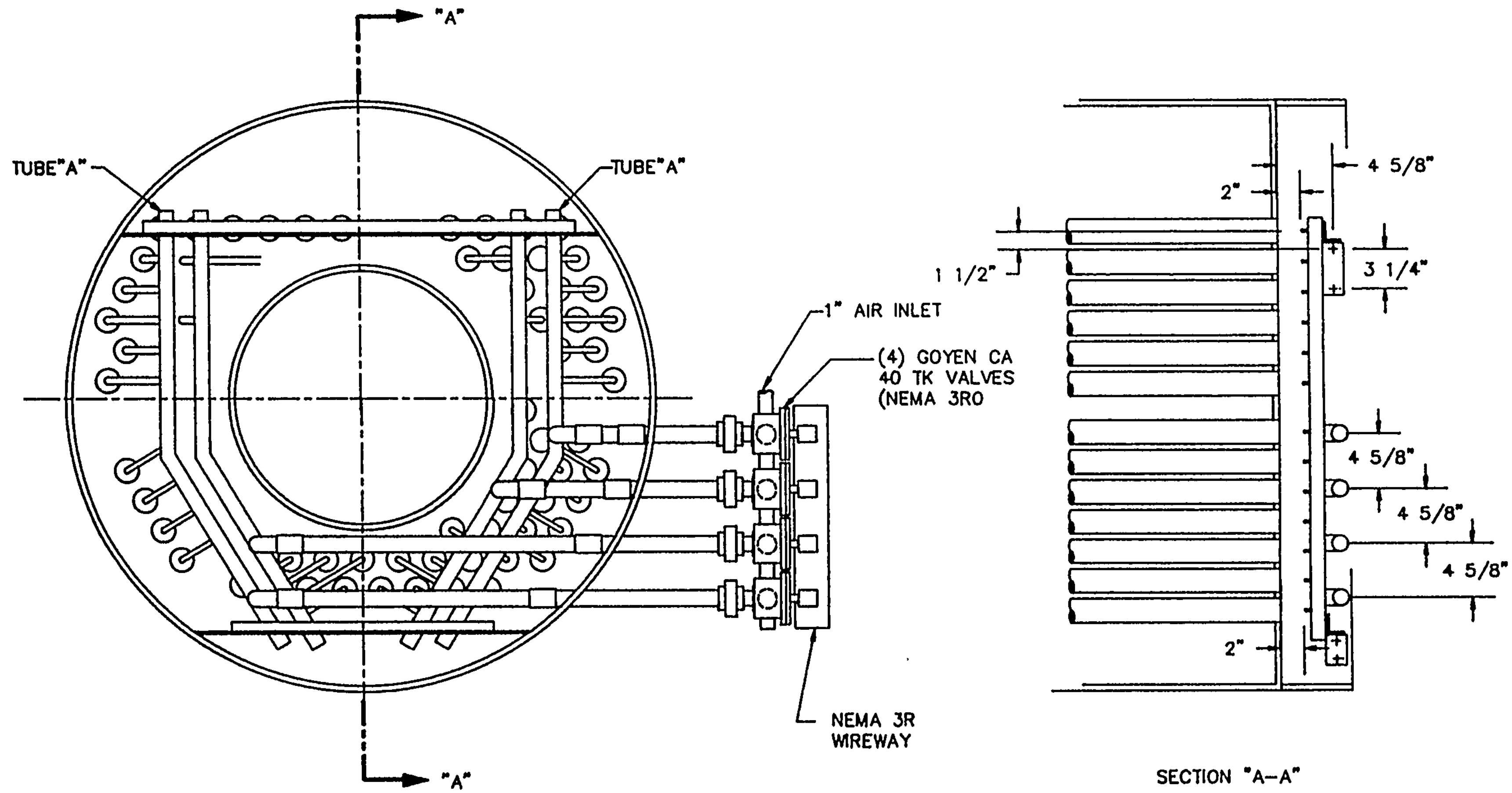

Figure 2.13 Compressed Air Soot Blower System Configuration

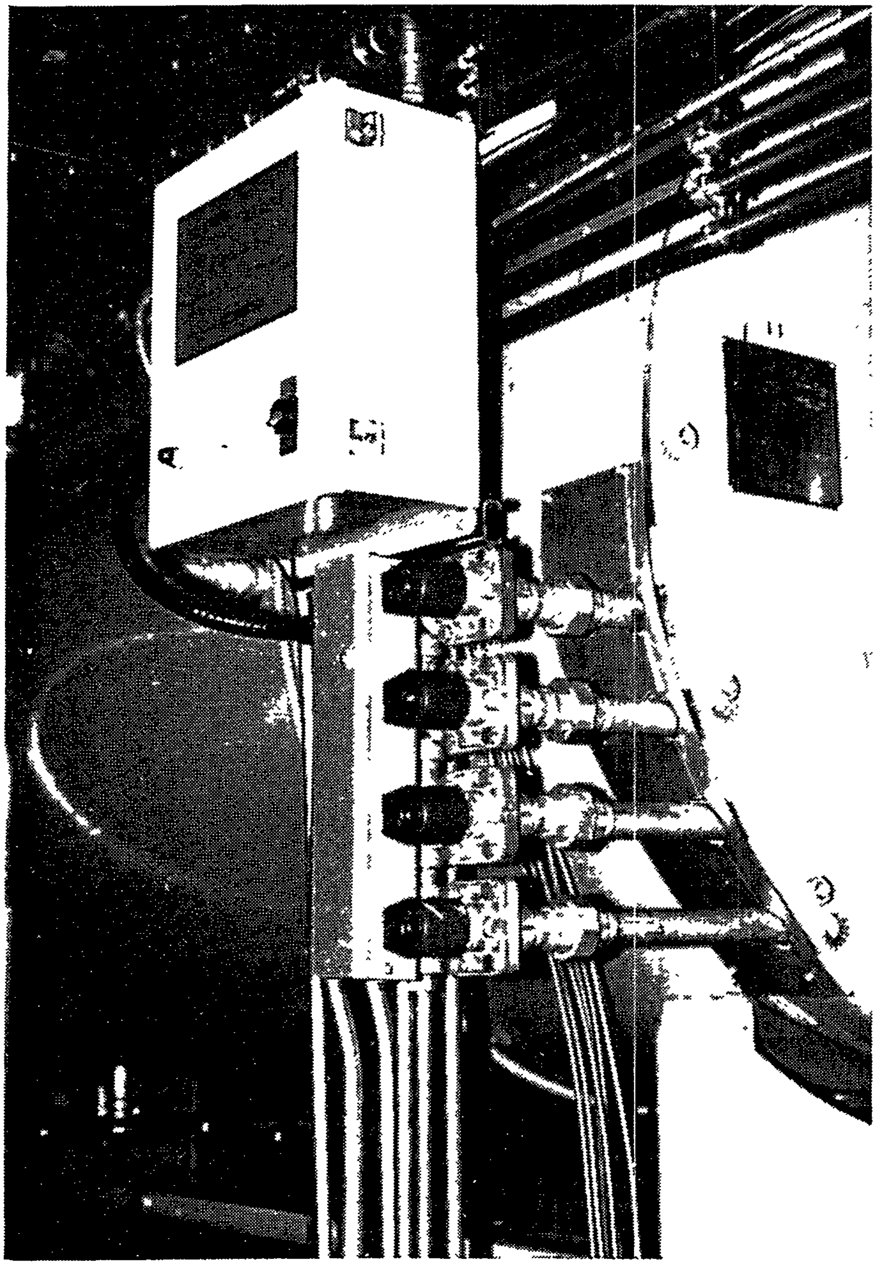

Figure 2.14 Soot Blowing System External Piping and Control Cabinet

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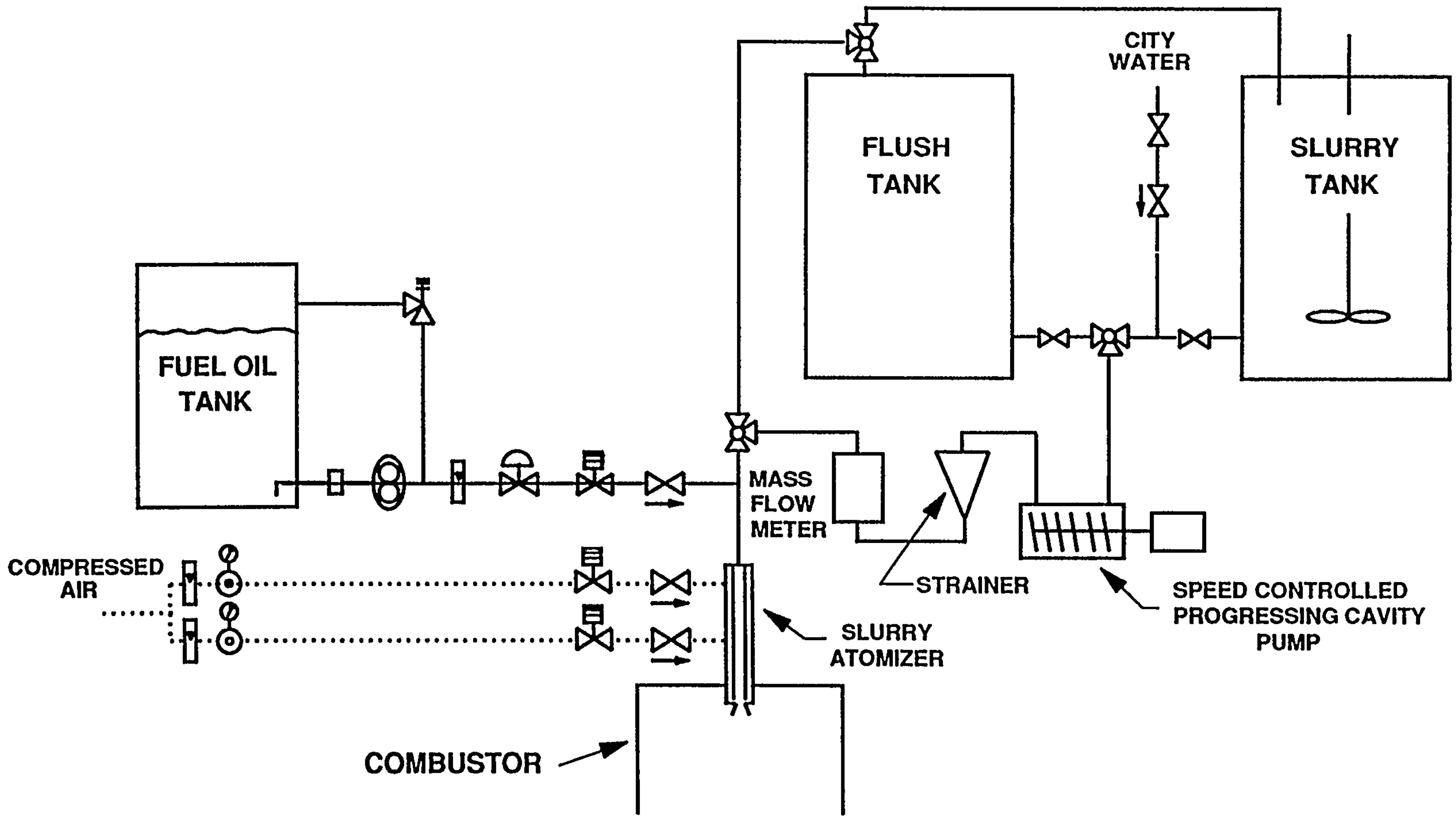

Figure 2.15 Flow Schematic of the Fuel Delivery System

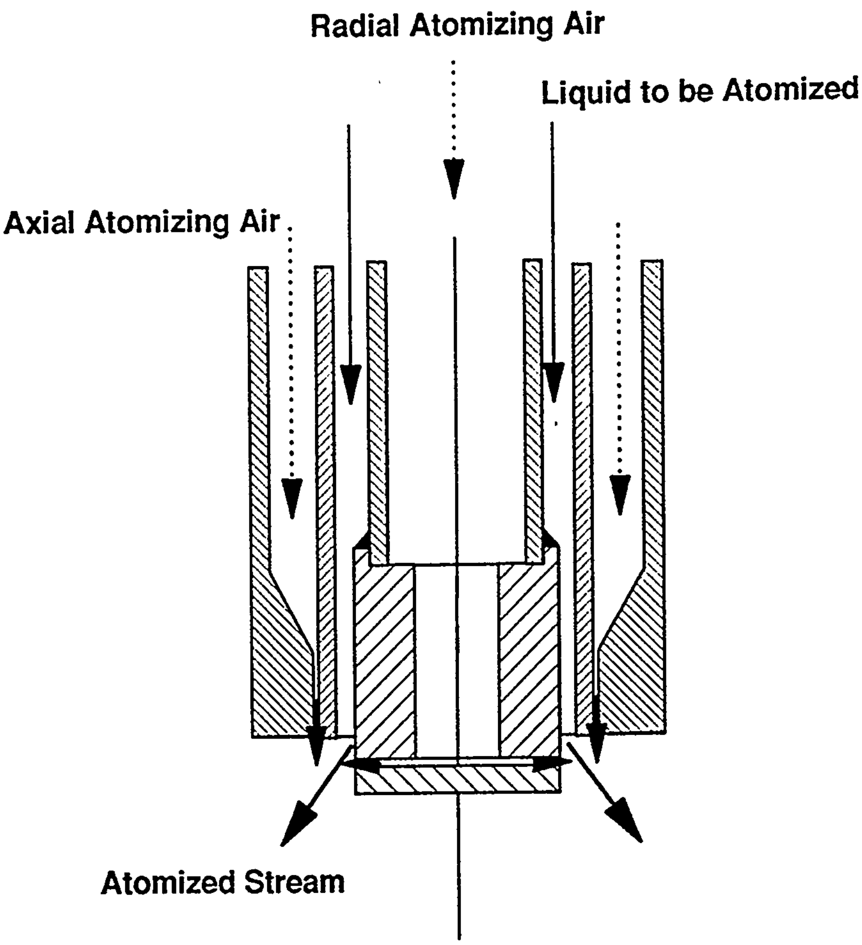

Figure 2.16 Tecogen Variable Spray Angle (VSA) Atomizer

TABLE 2.2

TECOGEN VSA ATOMIZER FEATURES

- Spray Angle Adjustable On-Line by Controlling Atomizing Air Flow – Allows Compensation for Slurry Properties
- Low Slurry Pressure
- External Mix/Low Wear
- Low Atomizing Air Flow
- Water or Air Cooled
- Operates on Both Slurry and Heating Oil
- Simple Construction/Low Cost

In designing the variable spray angle (VSA) atomizer, an analogy was made with Prefilming Airblast atomizers which are used for fuel injection in aircraft and industrial gas turbines. In a prefilming airblast atomizer, the liquid to be atomized is first spread out into a thin continuous sheet and then exposed on both sides to high velocity air. Lefebvre[2] derived a general correlation that takes into account fluid properties, velocity, geometry , and the air/liquid mass ratio on Sauter Mean Diameter (SMD). SMD is the diameter of a droplet whose ratio of volume to surface area is equal to that of the entire spray sample. This relationship is:

$$\begin{aligned} SMD = 0.073 \left[\frac{\sigma_L}{\rho_A U_A^2}\right]^{0.06} \left[\frac{\rho_L}{\rho_A}\right]^{0.1} D_p^{0.4} \left[1 + \frac{1}{ALR}\right] \\ + 0.015 \left[\frac{\mu_L^2 D_P}{\sigma_L \rho_L}\right]^{0.5} \left[1 + \frac{1}{ALR}\right] \end{aligned} \tag{10}$$

where:

σ is surface tension
ρ is density
μ is viscosity
U is the flow velocity
D_p is the diameter of the prefilming lip
ALR is the air /liquid ratio
Subscripts A and L are for air and the liquid being atomized, respectively.

Either one of the two terms in equation 10 dominates, depending on the properties of the fluid being atomized. For fluids with low viscosity, such as water or distilled light fuel oils such as kerosene, the first term in equation 10 dominates. However, for viscous fluids such as heavy fuel oils and CWS, the second term dominates. The effects of ALR and fluid properties are shown in Figure 2.17 for water, number 6 fuel oil (at 210°F), and CWS for viscosities ranging from 100 to 600 centipoise.

In making the analogy between a prefilming airblast and the VSA atomizer, one should be sure to consider that, due to the perpendicular orientation of the atomizing streams, the VSA imparts higher shear and, as such, it is expected that the coefficients of the two terms in equation 10 may be different; however, for design purposes, this equation is sufficient. The interesting feature of Figure 2.17 is that there is only a marginal increase in atomizer performance as the ALR is increased above 0.5.

Figures 2.18 through 2.20 show the variation in spray angle which can be achieved by varying the atomizing air flows. These photographs were taken with the atomizer operating with water at a flow rate equivalent to 5 MMBtu/hr. Characterization of the atomizer performance with both water and coal slurry was conducted by the University of Alabama using a Malvern Instruments particle sizer. The slurry used was produced by Jim Walter Resources, Inc., and had an apparent viscosity of 300 cp at 600 reciprocal seconds. Figure 2.21 gives the Sauter Mean Diameter (SMD) versus air liquid ratio

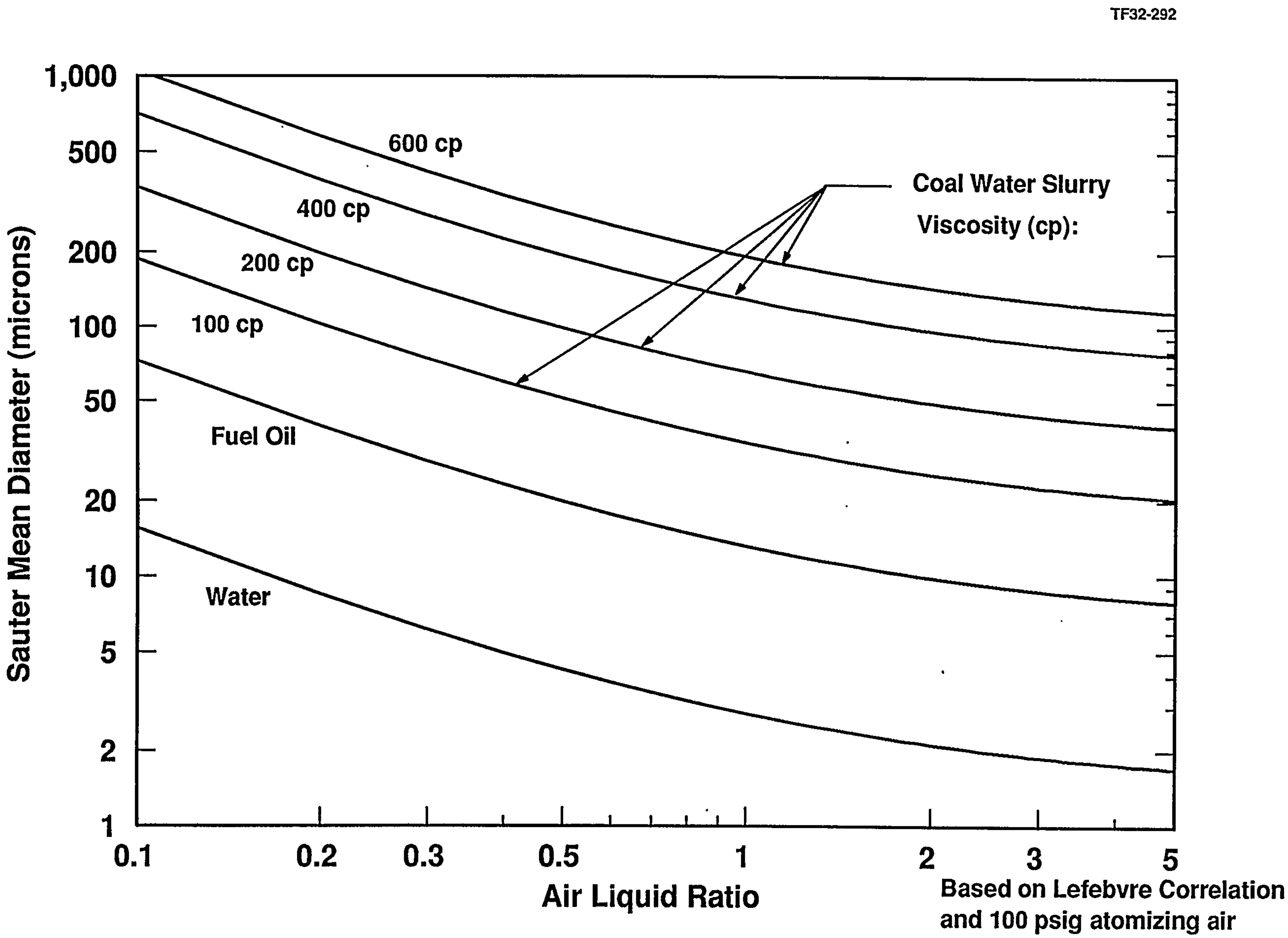

Figure 2.17 Effect of Air/Liquid Ratio and Liquid Viscosity on Twin-Fluid Atomizer Performance

Figure 2.18 VSA Atomizer with Narrow Spray Angle

Figure 2.19 VSA Atomizer with Intermediate Spray Angle

Figure 2.20 VSA Atomizer with Wide Spray Angle

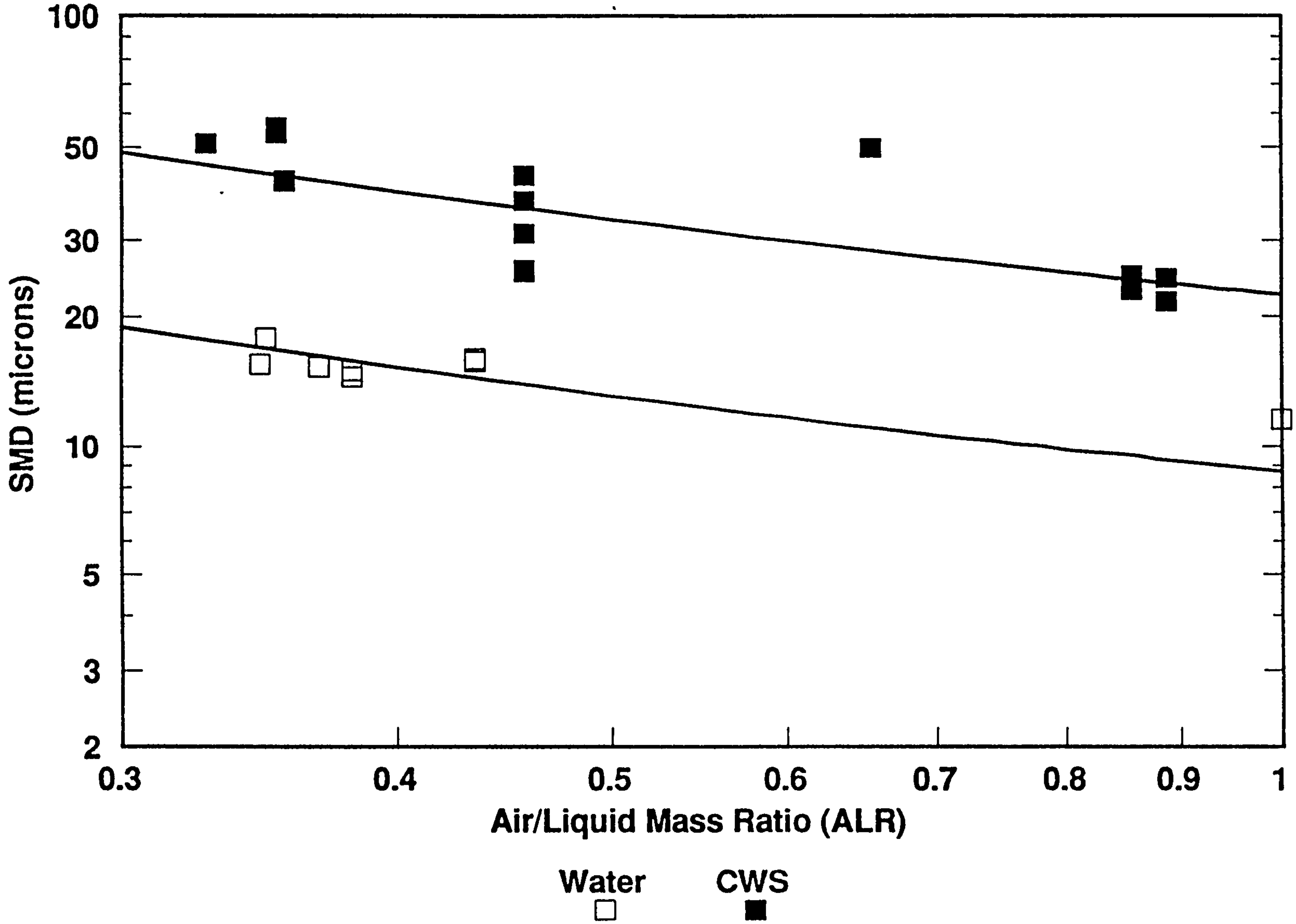

Figure 2.21 Data Reduction for Tecogen VSA Atomizer

for the two fluids. SMD is defined as the diameter of droplet whose ratio of volume to surface area is equal to that of the entire spray sample. Figure 2.22 gives the particle size distribution for two of the cases. This data are uncorrected for instrument obscuration.

The fuel system has also been simplified by the development of this atomizer, because the atomizer is capable of operating on fuel oil, slurry, and fuel oil and slurry simultaneously. This eliminates the need for a separate warm-up burner, and simplifies changing from oil to slurry and back, since air and/or water purging of the inactive nozzle is not required.

Also developed specifically for the fuel delivery system was a slurry strainer. The strainer design (see Figure 2.23) eliminates the dead spots found in a conventional basket strainer. This strainer, working in conjunction with the large slurry passages of the VSA, has eliminated plugging difficulties commonly encountered in slurry systems due to oversized coal particles or foreign matter.

2.2.4 Emissions Controls

To meet the targeted emission goals of no more than 1.2 lbs of SO_2 and 0.03 lbs of particulates per million Btu, the CWS-fired commercial scale space heating system must include flue gas pollution control equipment. Uncontrolled, the system will generate emissions of approximately 4 lbs of SO_2 per million Btu and 6.25 lbs of particulates per million Btu, depending on the exact coal composition. As discussed in Section 2.2, the control of NO_x to targeted levels is achieved through control of the combustion process and therefore, the pollution control equipment does not include NO_x reduction capabilities.

To achieve the required goals of 70% reduction of SO_2 and 99.5% particulates capture, dry duct injection of sorbent in conjunction with a fabric filter is utilized. In the duct injection process, a dry, powdered sorbent, namely sodium bicarbonate or trona, is injected directly into the flue gas duct upstream of the particulate control device. The sorbent undergoes rapid decomposition in the hot flue gas, creating a highly porous, reactive particle. SO_2 is absorbed onto the particle initially at the point of injection, and further absorption of SO_2 occurs in a baghouse, as the sulfur-laden gases pass through the filter cake. The baghouse is considered an integral part of the SO_2 removal equipment. Figure 2.24 illustrates the sorbent storage and injection equipment configuration. A variable speed screw feeder is used to meter and control the flow of sorbent to a compressed air-driven pneumatic eductor, which conveys the sorbent to the boiler exhaust duct. The screw feeder hopper can be loaded manually with bagged sorbent, or in a bulk mode through the use of a "super sack."

The baghouse is a conventional pulse jet fabric filter unit with a cloth surface area of 457 square ft. The unit is 4' by 4' with a height of approximately 13', and consists of 36 100" long bags. The bag material is P84, a nonflammable and thermostable organic fiber with a maximum use temperature of 500°F. Figure 2.25 is a photograph of the unit. The tall, upright configuration was chosen to minimize floor area requirements, since there were no overhead restrictions at either

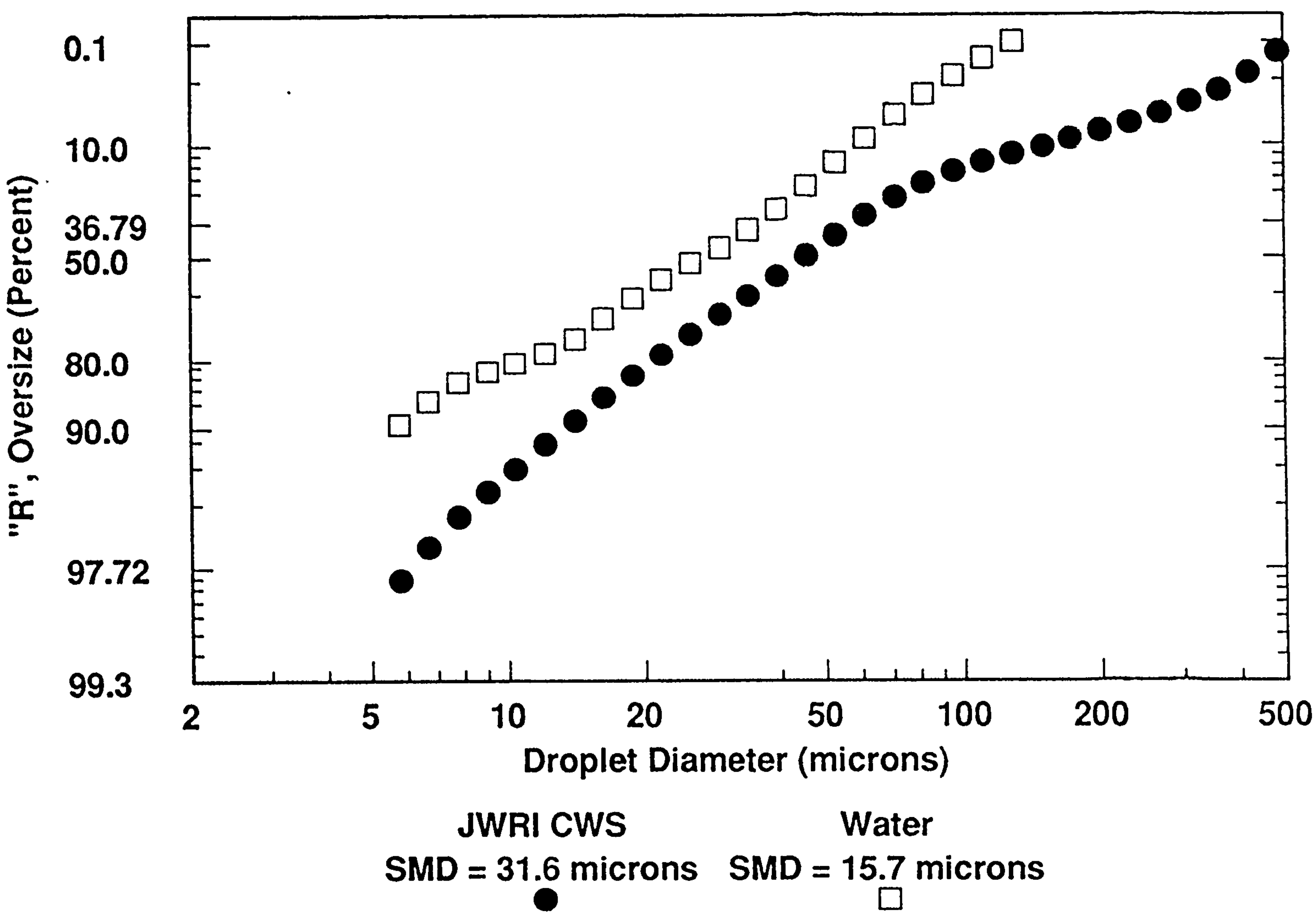

Figure 2.22 Droplet Size Distribution, Tecogen VSA Atomizer
Fluids: JWRI Coal Water Slurry (63.86% Solids) and Water

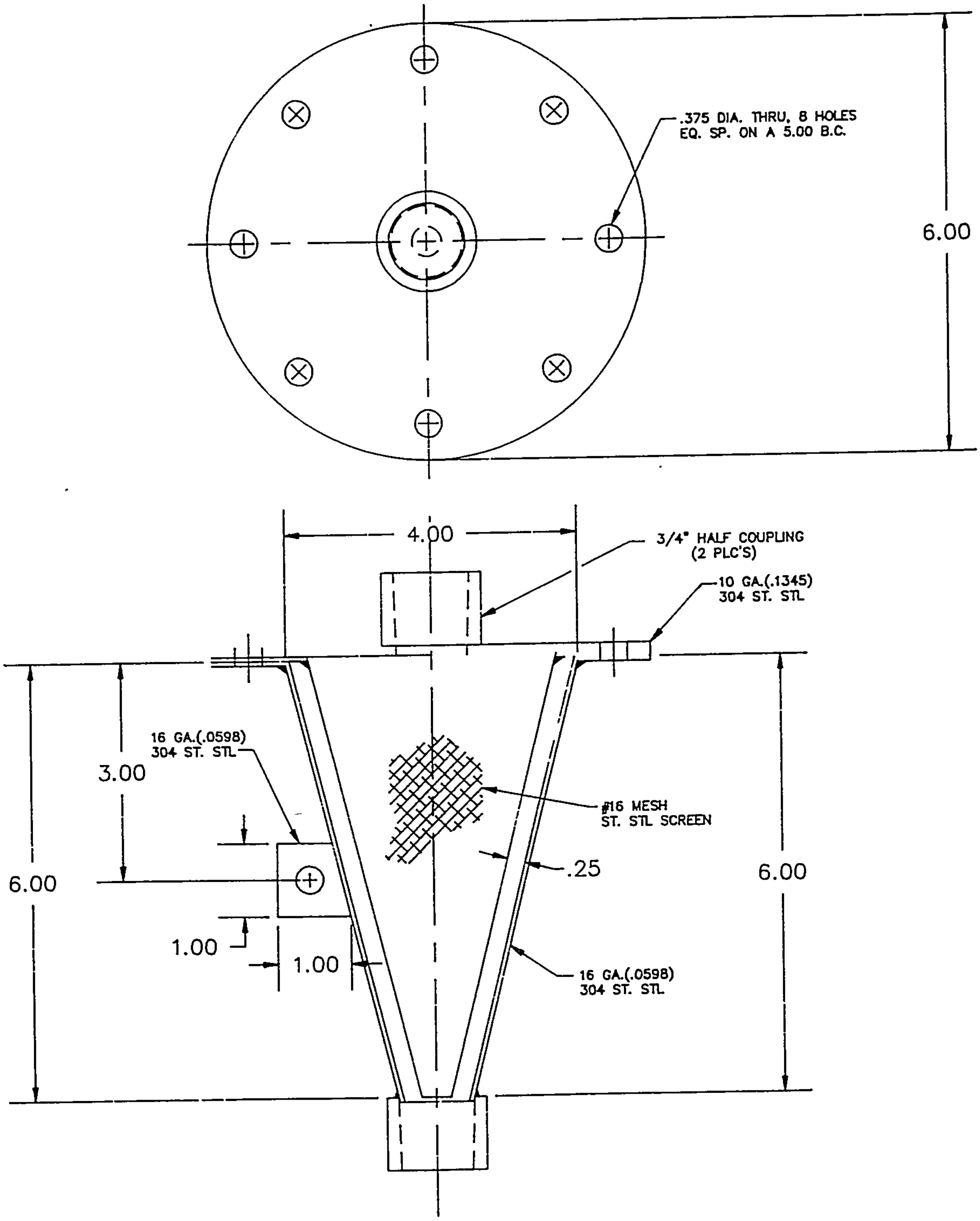

Figure 2.23 Slurry Strainer

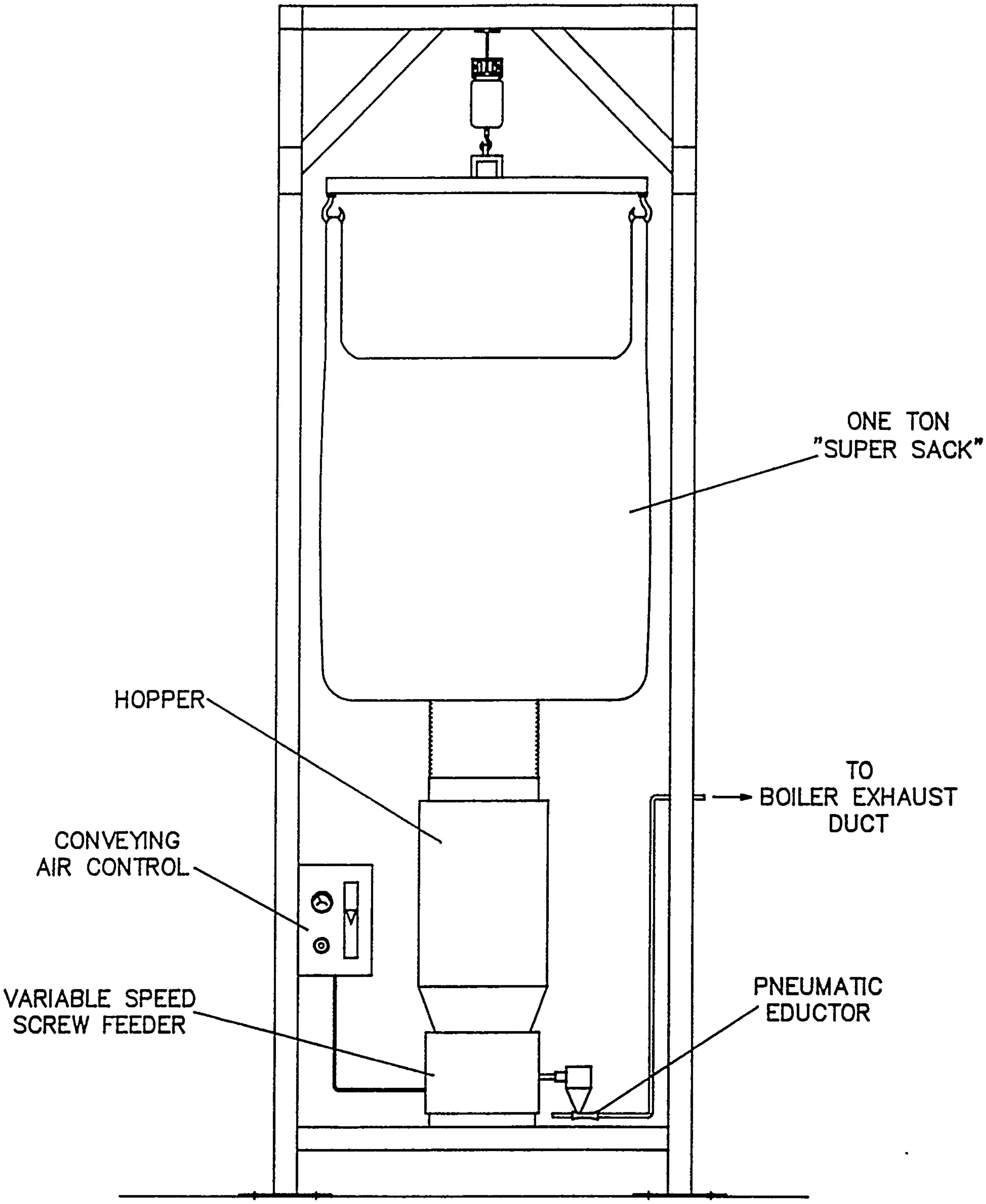

Figure 2.24 Sorbent Storage, Feed, and Conveying System

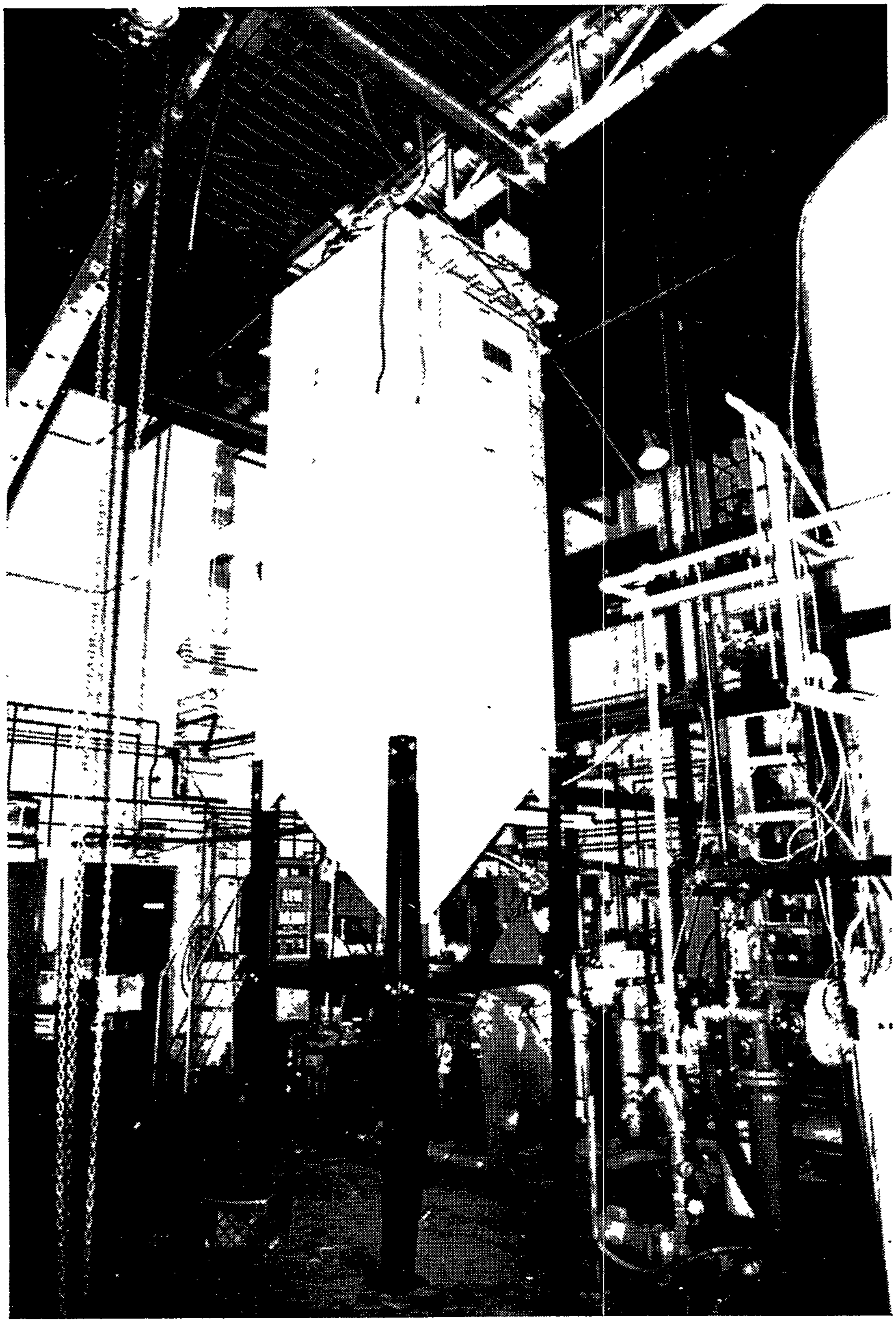

Figure 2.25 Baghouse Installation

Tecogen's laboratory facility or the demonstration site. Other geometries are available for applications where head room restrictions exist.

2.2.5 Controls

The space heating system was outfitted with a control system capable of ensuring safe, reliable, and fully automatic system operation. A process and instrumentation diagram for the process is shown in Figure 2.26. The control system consists of a General Electric Fanuc Series 90-30 Programmable Logic Controller. The controller provides for complete automatic or manual control of the system, including pushbutton start and stop, load following, safety interlocks, automatic fuel changeover, and alarm messages. The system has 6 analog output channels, 8 analog input channels, 4 thermocouple channels, 28 discrete output channels, and 16 discrete input channels. Operator interface is through a CRT-based operator interface terminal. This terminal has flow schematics which display key process variables and setpoints, and programmed function keys to allow complete control of the system, including selection and manipulation of all proportional control loops in manual mode.

Along with termination point junction boxes for sensors and controllers, the system has 2 main electrical enclosures: a main control panel and an instrument panel. The main control panel is shown in Figures 2.27 and 2.28. The main control panel houses the Operator Interface Terminal, Programmable Logic Controller, relays, and data acquisition boards. Figure 2.29 shows the internals of the instrument enclosure. This enclosure houses the atomizing air controllers and flowmeters, the fuel oil flowmeter and control valve, and miscellaneous pressure switches, transducers, and gauges.

The system also was equipped with a personal computer-based data logging system to permit monitoring and data reduction of key system variables needed for the development effort.

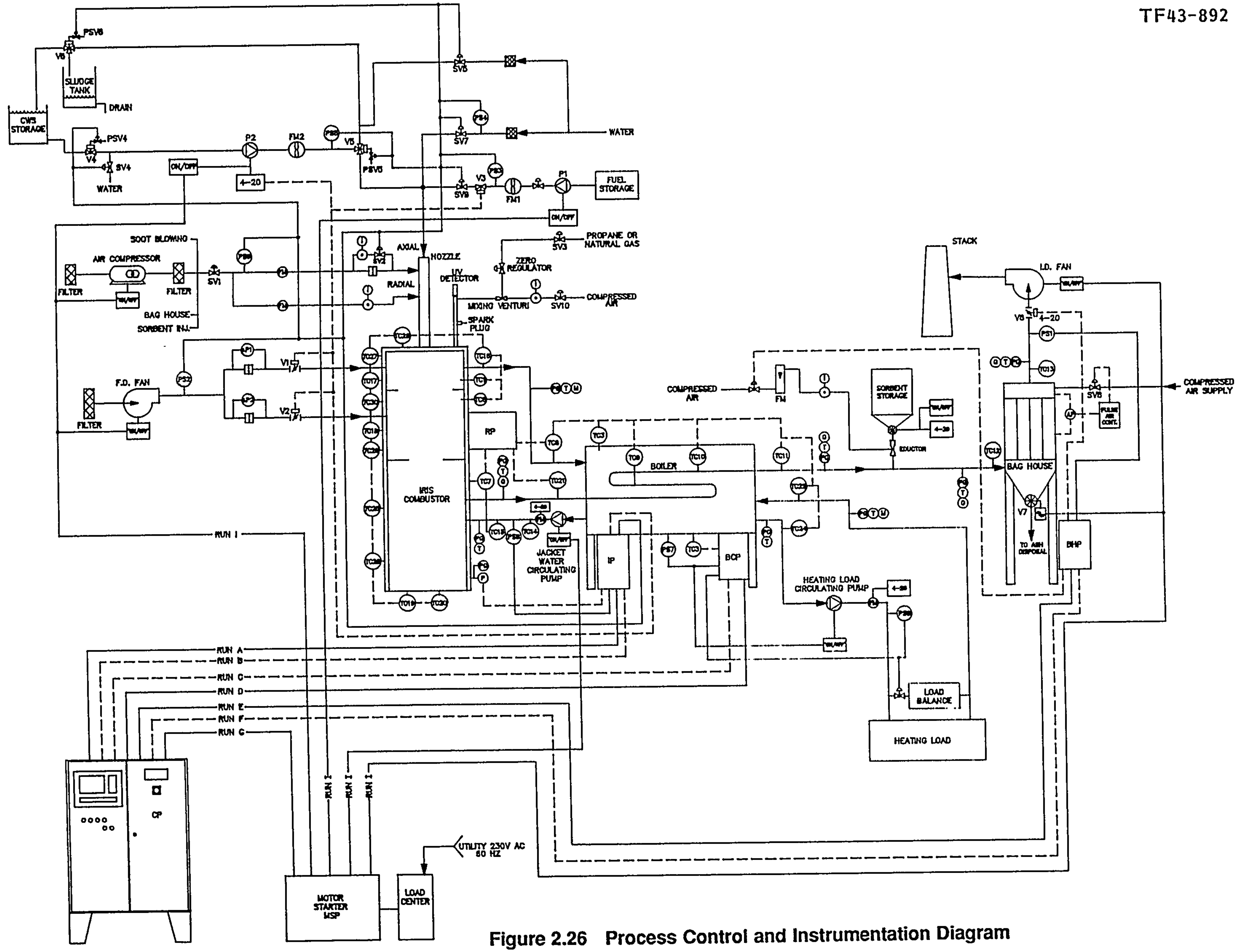

Figure 2.26 Process Control and Instrumentation Diagram

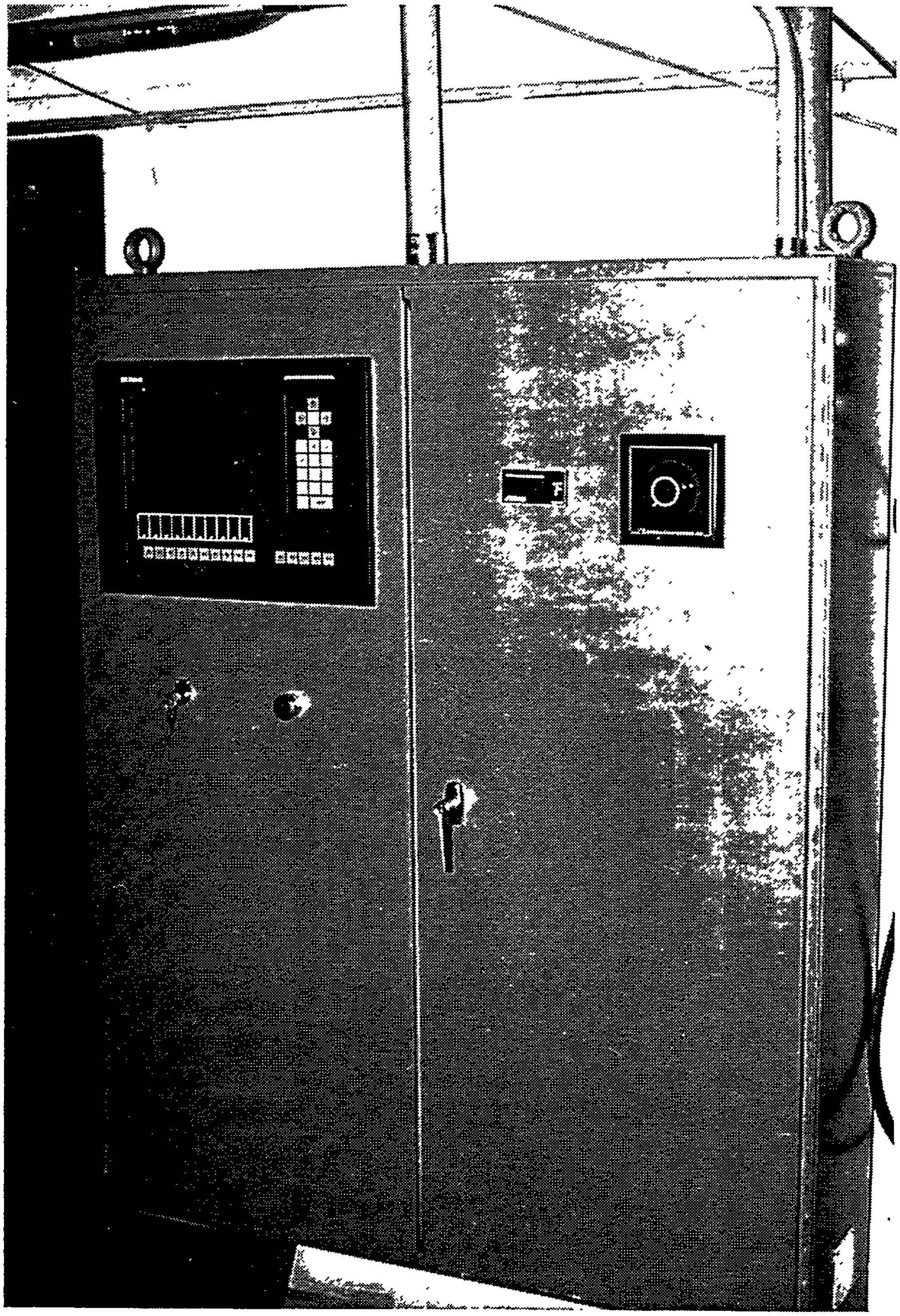

Figure 2.27 External View of the Main Control Panel

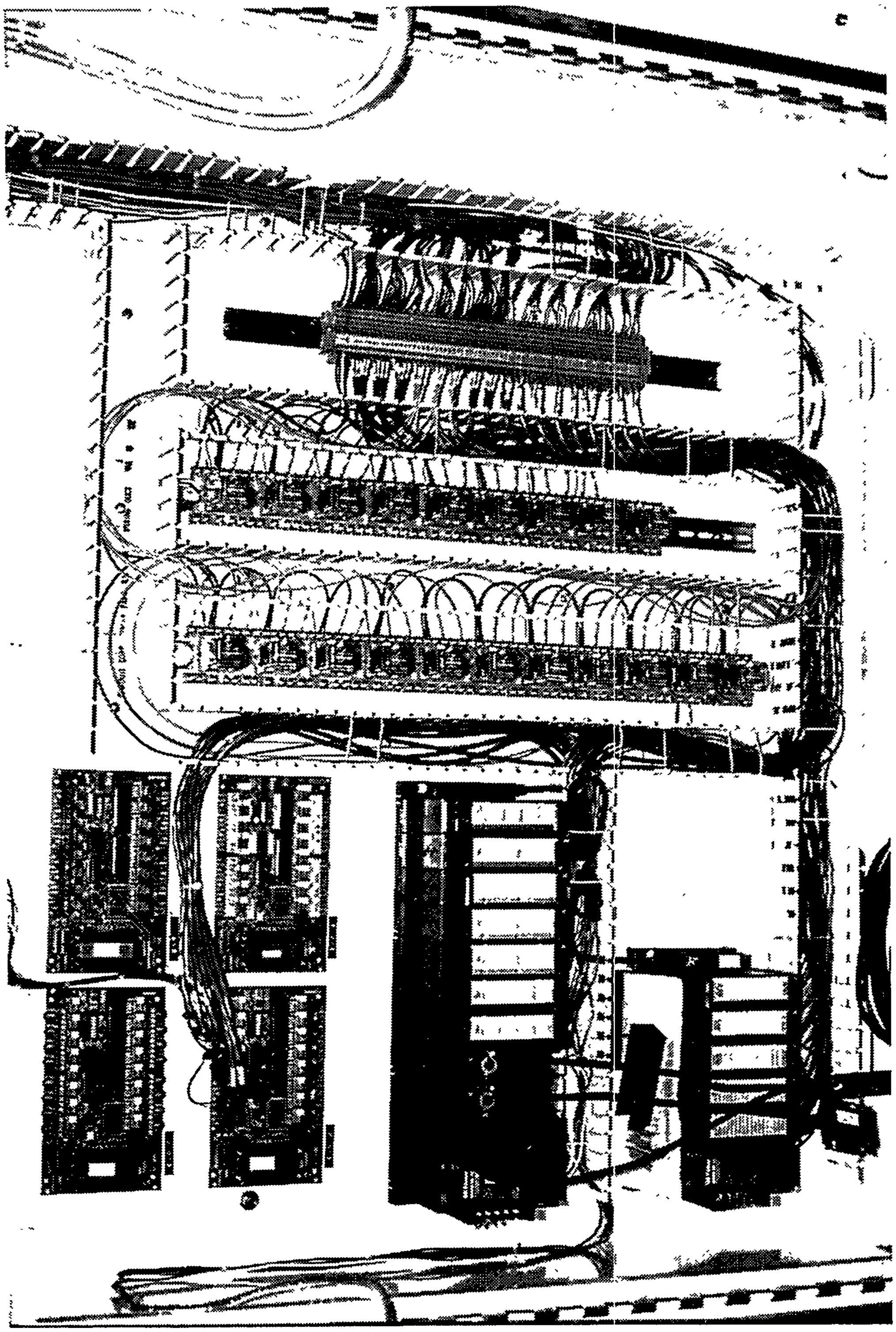

Figure 2.28 Internals of the Instrument Enclosure

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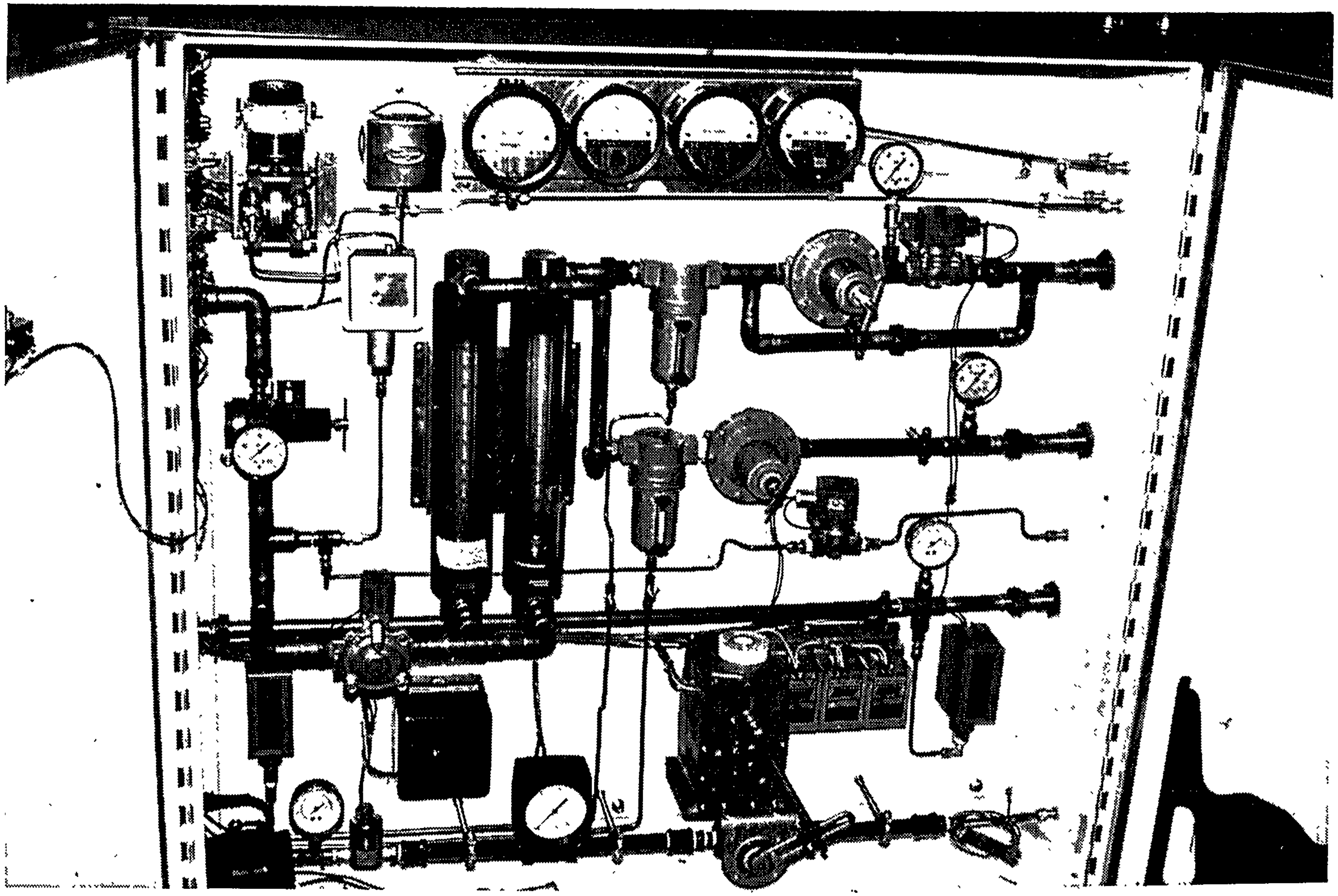

Figure 2.29 Internal Configuration of the Control Enclosure

3. SLURRY PREPARATION

3.1 SLURRY PREPARATION FACILITY

At the start of this development program, it was recognized that, although CWS has great potential as an alternative fuel form for smaller scale applications, CWS fuel is not easily obtained or widely produced at this time. Most suppliers and investigators are limited in their production capability and would be hard pressed to meet the demands of a commercial scale system with slurry firing rates of approximately 60 gph. To ensure a supply of CWS for the program, and also to provide both an engineering and economic database for slurry production at larger scales, a slurry preparation facility was set up to produce CWS for the program.

A process flow diagram for the system is given in Figure 3.1. Crushed coal (3" x 0") is received in 1-ton supersacks and fed to a hammermill via a variable speed screw feeder. The grinder has an integral aerodynamic classifier which limits the ground coal top size to under approximately 175 microns. From the classifier, the coal is conveyed to a series arrangement of primary and secondary cyclones and discharged into a mixing tank via rotary valves. The conveying air can either be operated in a closed loop configuration or in a once through, open loop configuration. It was found that with coal moisture content of approximately 10% or greater, the system must be operated in the open loop configuration to prevent moisture build-up in the conveying lines and resulting coal deposition. A pulse jet baghouse is used to collect fines passing the cyclones, approximately 1% of the coal flow.

In the mixing tank, the pulverized coal is fully wetted with the help of tank mixers and a fluid circulation loop, which takes suction from the bottom of the mixing tank and discharges the coal/water mixture (CWM) onto the surface. An air-operated diaphragm pump is used to circulate the slurry and is also used as a transfer pump.

The system is operated in a batch mode by pre-filling the mixing tank with the necessary water and additives, and running the pulverizer until the CWM reaches a pre-determined starting point. The density of the slurry proved to be a key process control variable, in that it is an indirect measurement of slurry loading. Coalmaster A23, manufactured by Henkel Corporation, is used as a dispersant, and FloconC, manufactured by Pfizer Chemical, is used as a stabilizer. On a coal weight basis, their concentrations are, on average, 10,000 and 700 ppm, respectively.

Figure 3.2 shows the equipment configuration and Figures 3.3 and 3.4 are photographs of the equipment. The equipment is arranged on 2 independent structures: the grinding stand and mixing stand. System operation is from an operator station mounted on the mixing stand. System start and stop is via a single pushbutton, and the control system ensures proper sequencing and safety interlocks.

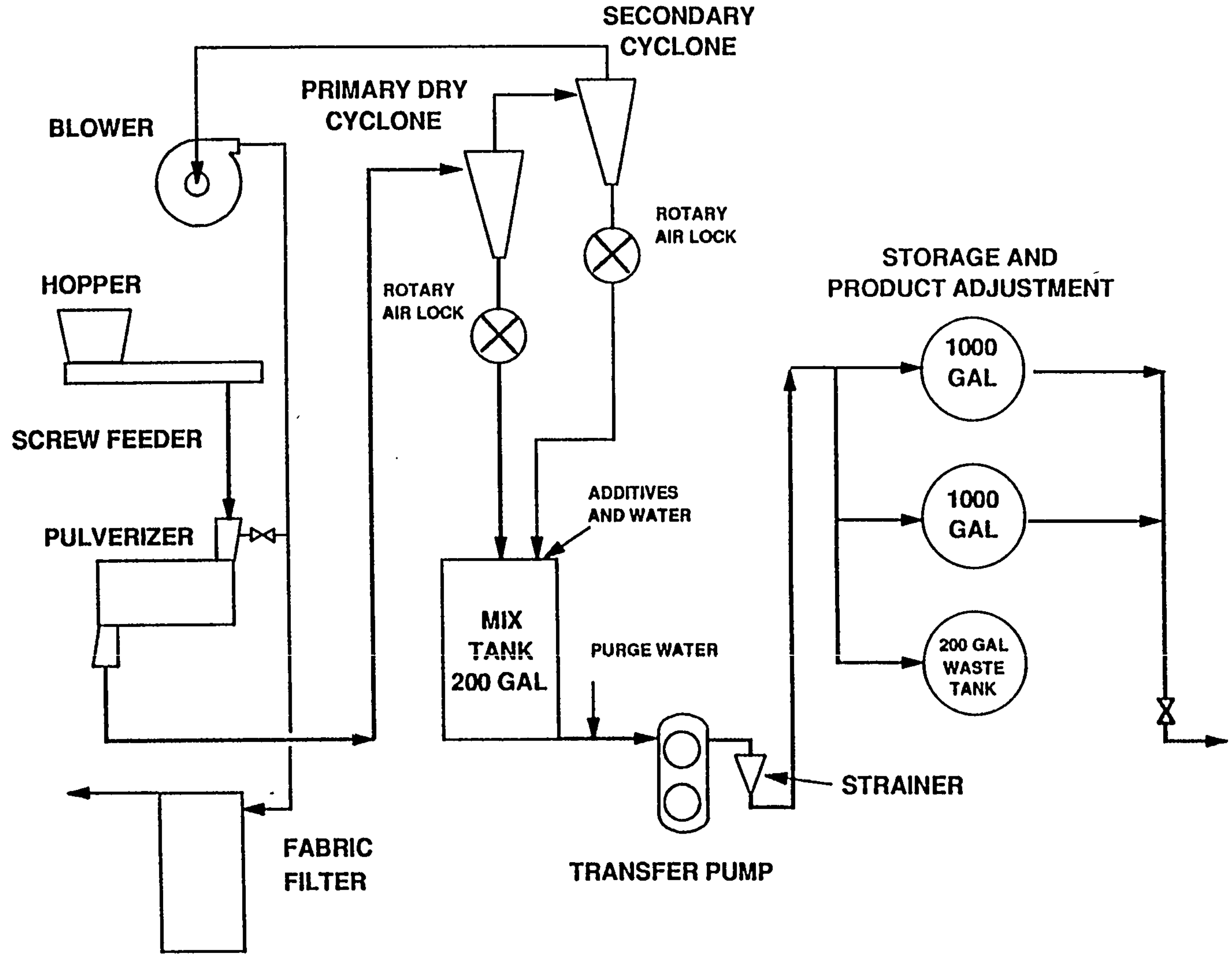

Figure 3.1 Slurry Production Facility Flow Schematic

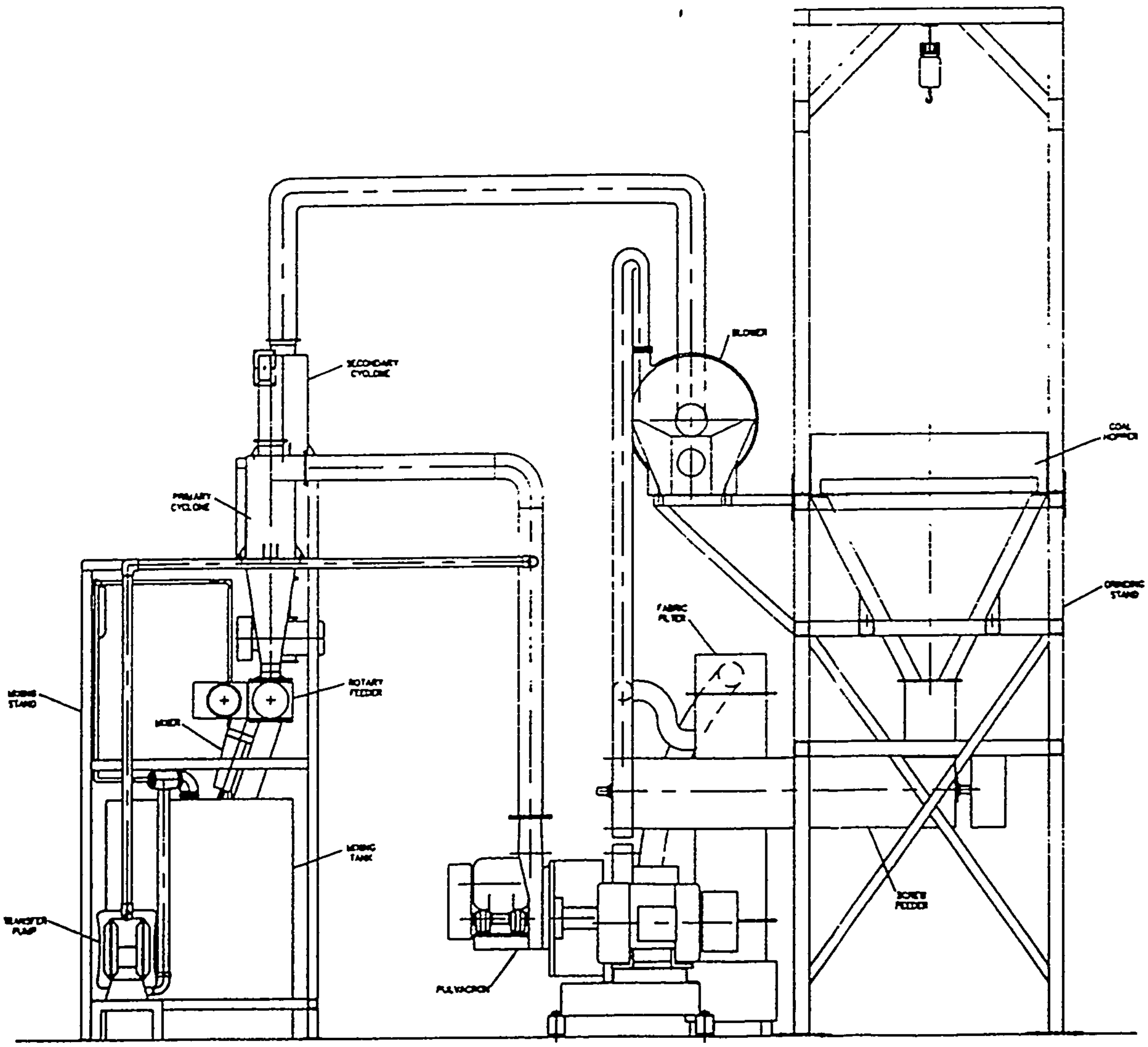

Figure 3.2 Slurry Equipment Layout

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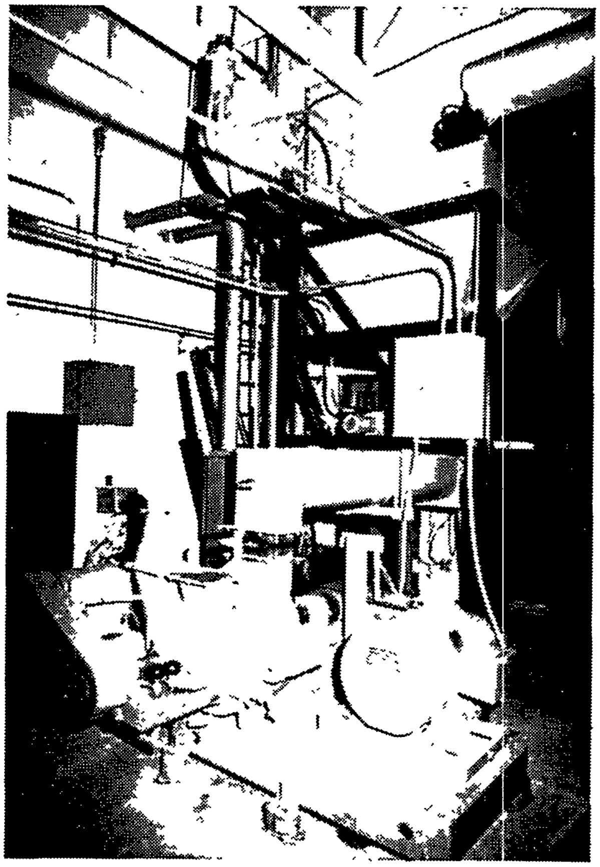

Figure 3.3 Slurry Production Facility Coal Grinding Stand

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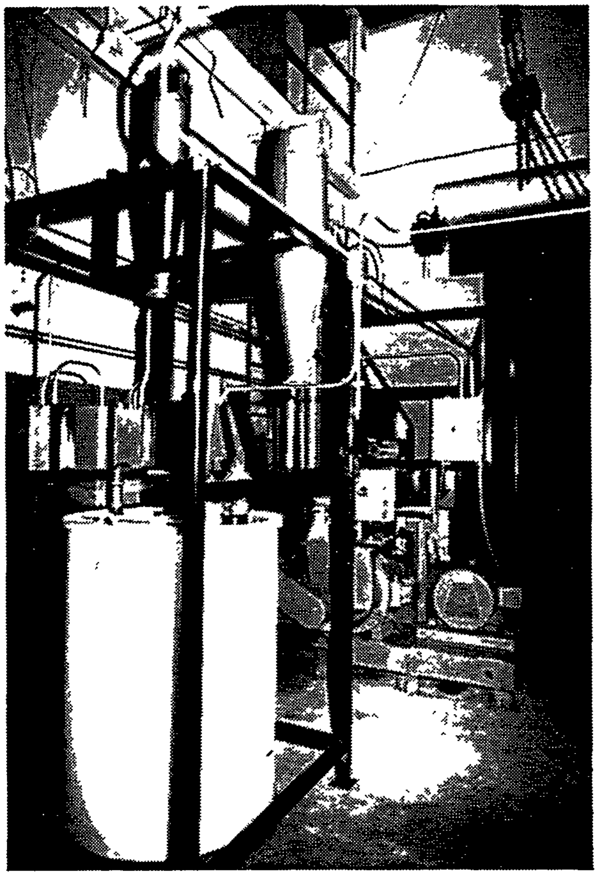

Figure 3.4 Slurry Production Facility Mixing Stand

3.2 SLURRY PRODUCTION

During the course of the development program, upwards of 75 tons of coal were processed into approximately 30,000 gallons of slurry. Three coals were processed: Eastern Kentucky Hazard Prince Mine, Illinois No. 5 Wabash Mine, and Illinois No. 6 Delta Mine. Table 3.1 gives the proximate and ultimate analysis for the three coals. The ash content of the Illinois No. 5 coal varied during the course of the program from 7 to 10% due to changes in the washing circuit at the mine and seam quality. These are run of mine coals without any additional washing or beneficiation other than that performed at the mine to ensure consistent quality.

Figure 3.5 gives typical coal particle size distributions for the coals after grinding. During testing with the Illinois No. 5 coal, the pulverizer was reconditioned and an additional beater plate was added along with a larger motor. This was done mainly to increase the throughput of the unit without sacrificing the grind size. With these changes, the system throughput was increased from 300 lbs/hr to 450 lbs/hr.

Table 3.2 gives the typical slurry properties for the three coals. As can be seen in the table, coal loadings were between 55% and 60%. For each of the coals, the maximum coal loading while maintaining a viscosity of 200 cp at 60 reciprocal seconds, was utilized. Figure 3.6 shows typical viscosities for the three CWS fuels.

TABLE 1

COAL PROXIMATE AND ULTIMATE ANALYSIS

KENTUCKY HAZARD PRINCE MINE					
Proximate Analysis			**Ultimate Analysis**		
	As Received	**Dry Basis**		**As Received**	**Dry Basis**
% Moisture	2.69	xxxxx	% Moisture	2.69	xxxxx
% Ash	3.62	3.72	% Carbon	78.91	81.09
% Volatile	35.93	36.92	% Hydrogen	5.25	5.39
% Fixed Carbon	57.76	59.36	% Nitrogen	1.63	1.67
	100.00	100.00	% Sulfur	0.74	0.76
			% Ash	3.62	3.72
Btu/lb (HHV)	14144	14535	% Oxygen (diff.)	7.16	7.37
% Sulfur	0.74	0.76		100.00	100.00
MAF Btu		15097			

ILLINOIS NO. 5 WABASH MINE					
Proximate Analysis			**Ultimate Analysis**		
	As Received	**Dry Basis**		**As Received**	**Dry Basis**
% Moisture	14.94	xxxxx	% Moisture	14.94	xxxxx
% Ash	6.17	7.25	% Carbon	64.30	75.60
% Volatile	33.25	39.09	% Hydrogen	4.24	4.98
% Fixed Carbon	45.64	53.66	% Nitrogen	1.43	1.68
	100.00	100.00	% Chlorine	.0.15	0.18
			% Sulfur	1.36	1.60
Btu/lb (HHV)	11439	13450	% Ash	6.17	7.25
% Sulfur	1.36	1.60	% Oxygen (diff.)	7.41	8.71
MAF Btu		14501		100.00	100.00

ILLINOIS NO. 6 DELTA MINE					
Proximate Analysis			**Ultimate Analysis**		
	As Received	**Dry Basis**		**As Received**	**Dry Basis**
% Moisture	9.44	xxxxx	% Moisture	9.44	xxxxx
% Ash	10.65	11.76	% Carbon	64.42	71.13
% Volatile	33.14	36.60	% Hydrogen	4.31	4.76
% Fixed Carbon	46.77	51.64	% Nitrogen	1.34	1.48
	100.00	100.00	% Chlorine	0.09	0.10
			% Sulfur	2.84	3.14
Btu/lb (HHV)	11592	12800	% Ash	10.65	11.76
% Sulfur	2.84	3.14	% Oxygen (diff.)	6.91	7.63
MAF Btu		14506		100.00	100.00

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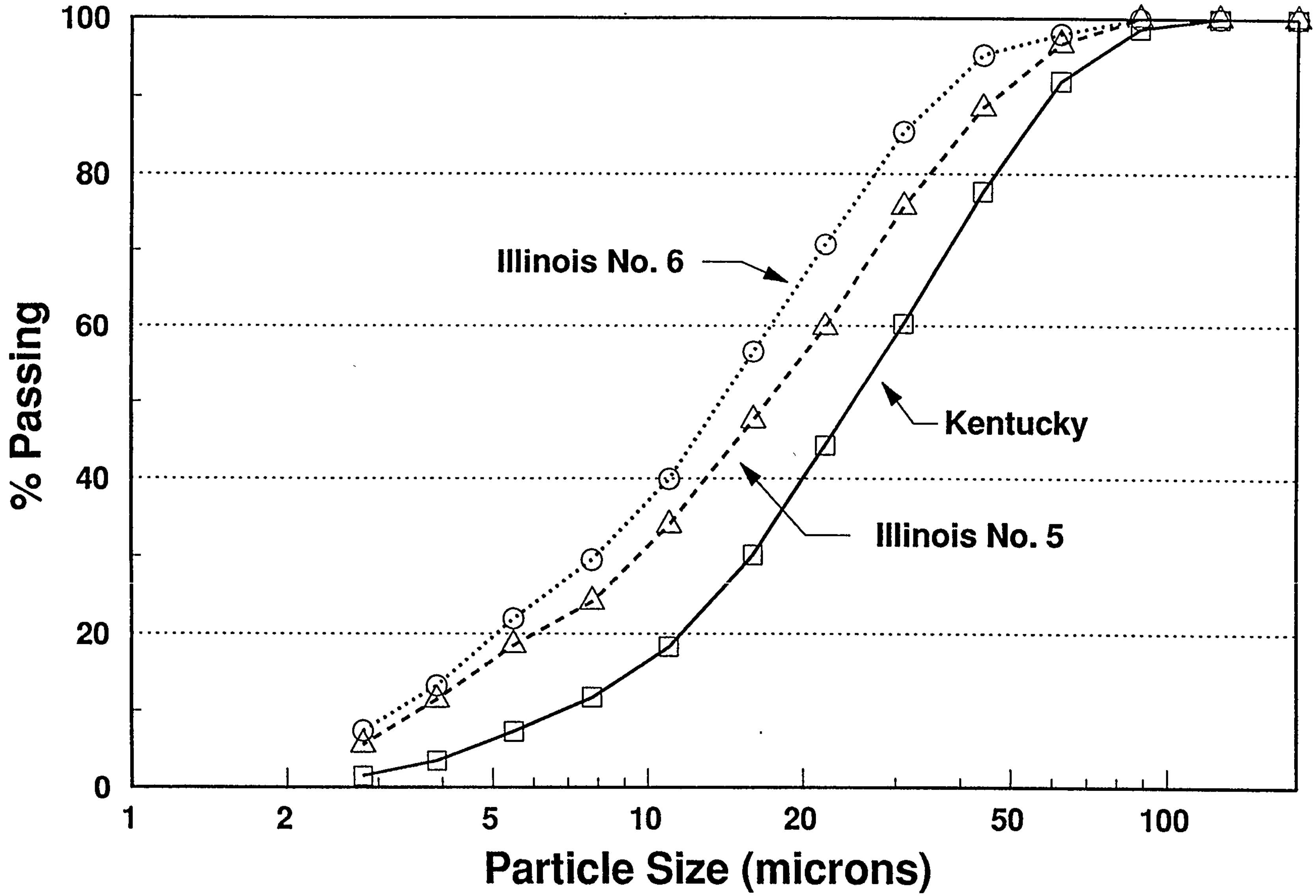

Figure 3.5 Typical Coal Particle Size Distributions for the Coals After Grinding

TABLE 2

TYPICAL SLURRY PROPERTIES

Coal	Kentucky	Illinois No. 5	Illinois No. 6
Coal Loading	59%	55%	57%
Particle Size (mmd)	30 μm	20 μm	18 μm
Specific Gravity	1.15	1.17	1.20
A23 (dry mass coal)	10,000 ppm	15,000 ppm	15,000 ppm
Flocon	700 ppm	700 ppm	700 ppm
Viscosity at 80 1/sec	200 cP	200 cP	200 cP
Heating Value	8,500 Btu/lb	7,400 Btu/lb	7,300 Btu/lb

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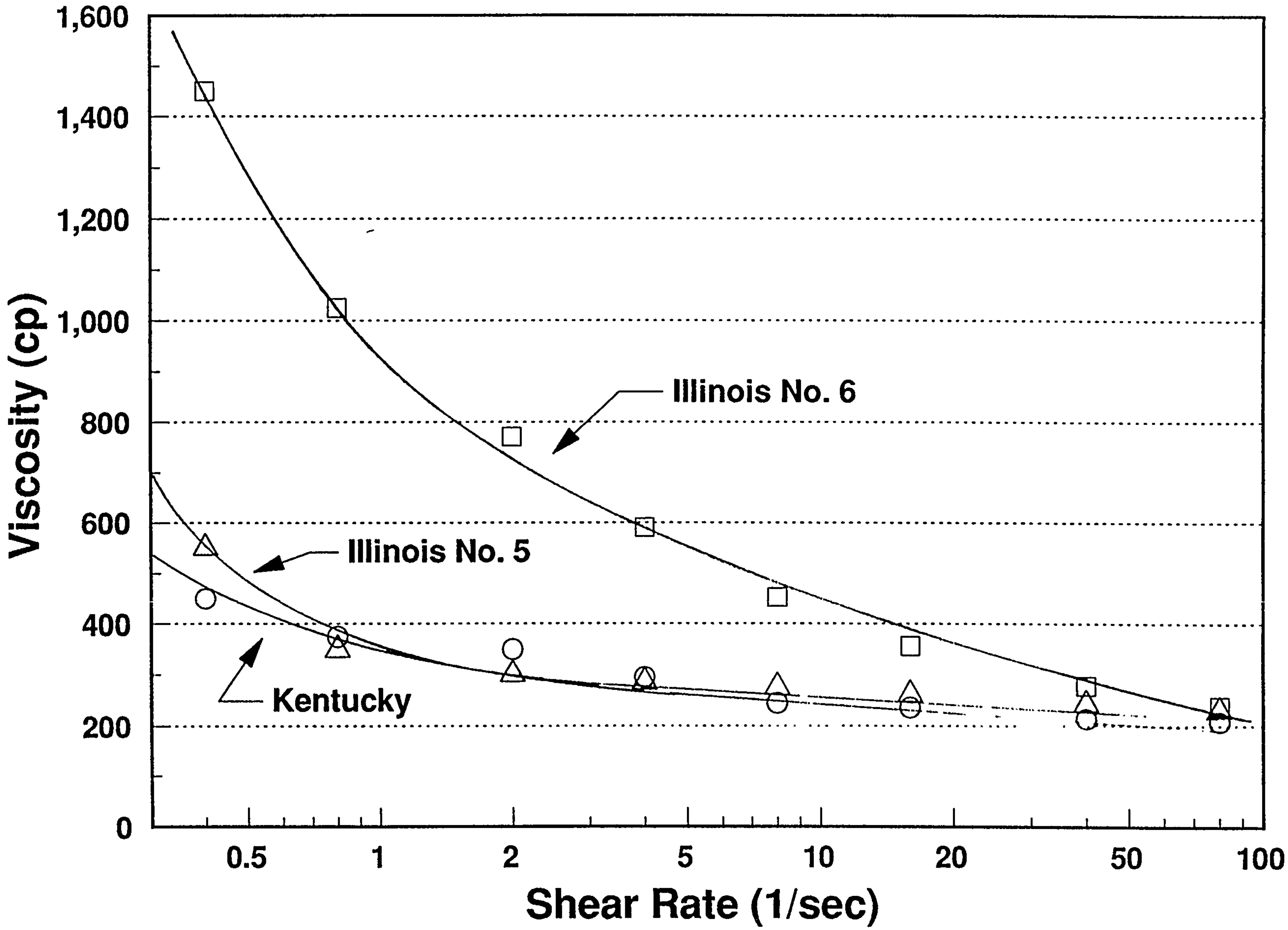

Figure 3.6 Typical Viscosities for the Three CWS Fuels

4. TEST RESULTS

Three series of tests were completed as part of the development program. The first series of tests, component and system tests, was performed to provide preliminary evaluation of component and system performance, identify key operating variables and their ranges, and establish appropriate operating conditions for subsequent Proof-of-Concept (POC) testing. These tests verified that the combustor technology had been successfully scaled to the commercial market size, that the integration of the major system components, especially the integration of the combustor with a firetube boiler was feasible, and that the system had the potential to meet the performance goals. This testing included over 100 hours of system operation.

The second series of tests, POC tests, was performed to evaluate overall performance of the space heating system and to demonstrate that the concept is technically feasible, both from a performance standpoint and from a maintenance and reliability standpoint. Combustion and thermal efficiencies, tendencies to slag, foul, erode and corrode, and gaseous and particulate emissions were evaluated.

The third test series involved a field demonstration of the integrated system at a representative commercial market sector facility. Short and long-term operation of the system was conducted to fully assess the performance and reliability of the combustion system. Of particular importance was the evaluation of system operability and maintenance requirements.

This section of the report discusses the results of the overall testing and operation of the individual components and the system. Since several design changes were made during the test campaign as a result of test results, a description of the hardware changes and final equipment configuration is included. In describing the test results, in particular the results of the field demonstration, close attention is paid to the operability of the system, and design improvements capable of increasing system reliability and maintainability are also discussed.

4.1 TEST OPERATION

4.1.1 System Tests

System testing consisted of both component and integrated tests to enable preliminary evaluation of individual components and subsystems. As part of this test series, a previously built prototype IRIS combustor was utilized to obtain preliminary combustor configuration design data. Among the design variables evaluated were:

Air inlet geometry and velocity
Partition diameter
Slurry injection location
Slurry atomizer types
Fuel oil nozzle arrangement
Pilot and ignition arrangements.

Over 80 hours of cold flow, atomization, and combustion testing were performed.

Based on these results and the previously discussed scale-up analysis, a commercial scale combustor was designed, built, and tested. For these preliminary combustor tests, the combustor was fired into a quench tank where the products of combustion were cooled using a water spray. Figure 4.1 shows the test configuration. These tests confirmed that the combustor could maintain stable combustion of coal slurry made from 3 parent coals: West Virginia Upper Elkhorn No. 3, Illinois No. 6, and Kentucky Hazard, at firing rates of up to 4.5 MMBtu/hr. Approximately 25 hours of combustor testing were achieved, with test durations from tens of minutes to several hours.

With initial combustor operation verified, the heat recovery and pollution control equipment and subsystems were installed, and preliminary check-out testing of the integrated system was performed. Figure 4.2 shows the test configuration. Ten integrated system tests were performed with an accumulated operation of over 100 hours. Table 4.1 lists of the test durations. During these tests, the system was operated at firing rates from 1.25 to 5 MMBtu/hr, utilizing coal water slurries produced via the previously described coal water slurry production facility.

4.1.2 Proof-of-Concept Tests

During the POC test period, the integrated system was operated for over 500 hours, with slurry-firing making up close to 70% of these operating hours. Table 4.2 gives a summary of the test operations. During the course of the testing, approximately 7,000 gallons of Kentucky slurry, 6,500 gallons of Illinois No. 5 slurry, and 3,500 gallons of Illinois No. 6 slurry were burned.

For most of this testing, the system was operated in the configuration shown in Figure 4.2. In this configuration, the heat recovery boiler was operated as a steam boiler with the steam vented to atmosphere, and the combustor and transition chamber operating on a separate circulating system discharging the extracted heat to a roof-mounted radiator. For the final tests, the boiler was operated as a hot water unit in the configuration shown in Figure 4.3, with the generated heat dissipated through a load compensating radiator.

4.1.3 Demonstration Operation

Demonstration operation involved use of the integrated system in a typical commercial market sector installation. The High Bay Building at the Illinois Coal Development Park (ICDP) was the host demonstration site. The ICDP is operated under a cooperative research and development agreement between Southern Illinois University at Carbondale and the Illinois Department of Energy and Natural Resources (IDENR). The objective of the ICDP is to conduct both basic and applied research aimed at the development of technologies to use the abundant coal resources in the State of Illinois in an environmentally sound and cost effective manner.

The High Bay Building is a multi-use facility housing classrooms, laboratories, combustion equipment, a grinding facility, and offices. The building has a floor plan of 12,400 ft^2 and an enclosed volume of approximately 330,000 cubic feet. The high bay area is 36' by 122', with a 36' roof height. This area was utilized to house the space heating system. Figure 4.4 shows the building layout.

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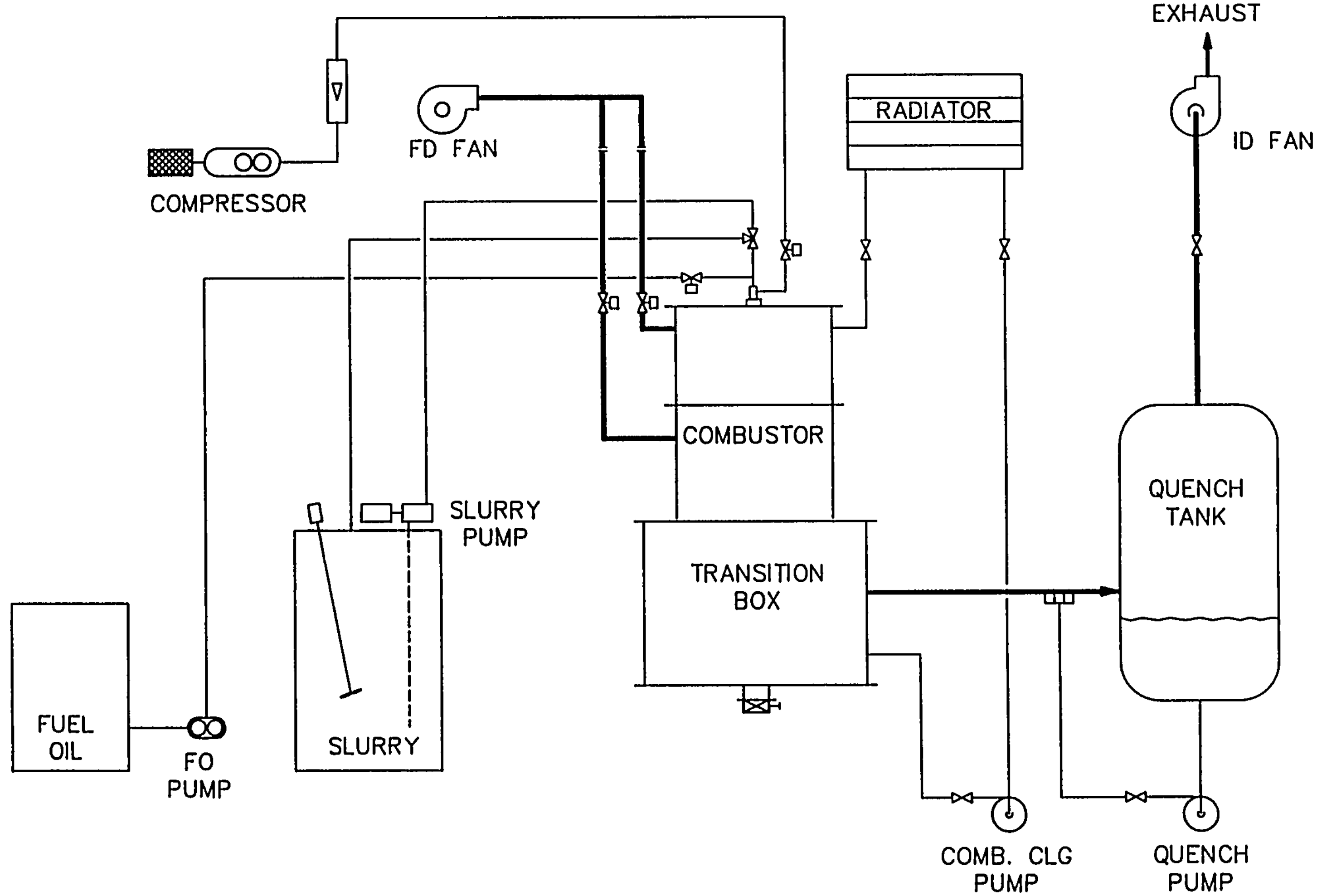

Figure 4.1 System Tests Configuration – Combustor Test Series

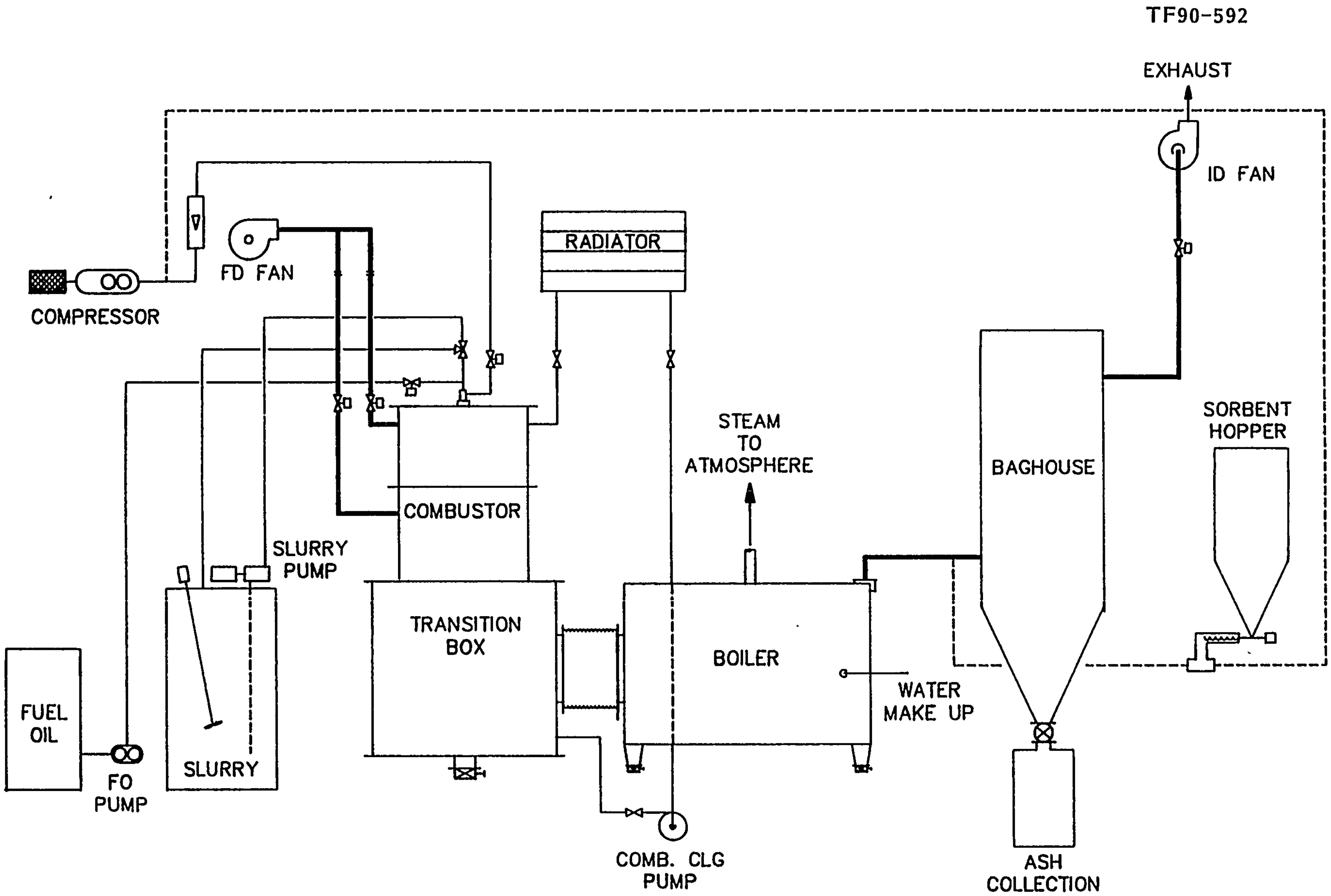

Figure 4.2 Schematic of System Test Configuration

TABLE 4.1

INTEGRATED SYSTEM TEST SUMMARY

DATE	TEST DURATION (HOURS)
11/12	3
11/13	5
11/15	7
11/21	6
12/3	8
12/17	13
12/19	10
12/27	7
1/3-4	36
1/7	8

TABLE 4.2

POC TEST SUMMARY

Date	Length of Test (Hours)	Length of Slurry Firing (%)	Coal
January			
15	8	62	Kentucky
February			
4	8	62	Kentucky
9	7	71	Kentucky
14	4	50	Kentucky
20	7	57	Kentucky
March			
6	6	67	Kentucky
11	4	50	Kentucky
17	8	75	Kentucky
25	4	50	Kentucky
30	6	66	Kentucky
April			
9	6	66	Kentucky
16	7	71	Kentucky
23	8	75	Kentucky
May			
14	3	0	Kentucky
15	4	75	Kentucky
22	7	57	Kentucky
June			
25	14	86	Kentucky
26	8	87	Kentucky
July			
1	16	87	Kentucky
7	6	66	Illinois No. 5
10	7	71	Illinois No. 5
15	7	71	Illinois No. 5
16	8	75	Illinois No. 5
21	7	71	Illinois No. 5
22	10	90	Illinois No. 5
August			
3	5	60	Illinois No. 5
5/6	26	92	Illinois No. 5
24	11	73	Illinois No. 5
25	10	90	Illinois No. 5
September			
2/3	34	94	Illinois No. 5
9	12	83	Illinois No. 5
10	6	83	Illinois No. 5
11	9	89	Illinois No. 5
15	7	71	Illinois No. 6
16/17/18	44	73	Illinois No. 5 & 6
29	7	57	Illinois No. 6
October			
30/1/2	60	50	Illinois No. 6
5–9	100	40	Illinois No. 6
TOTAL	511	66	94 Hours Kentucky 145 Hours Illinois No. 5 99 Hours Illinois No. 6

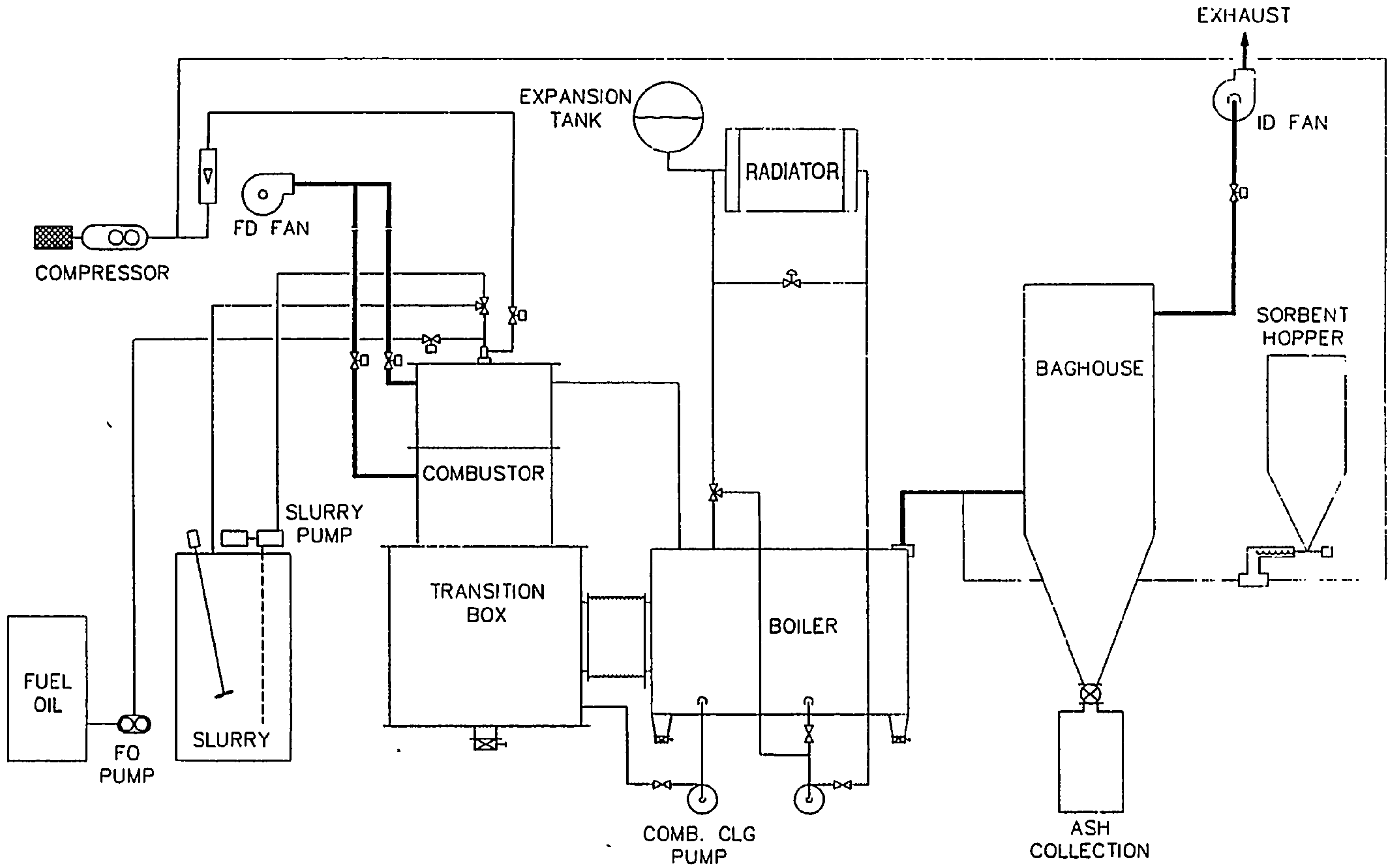

Figure 4.3 System Tests Configuration Integrated System Test Series – 10/7/92

Prior to installation of the coal slurry-fired space heating system, the High Bay Building was electrically heated with a combination of electric unit heaters and roof units with ducts. The electric unit heaters were replaced with hot water unit heaters supplied by distribution piping from the space heating system heat recovery unit.

Figures 4.5 and 4.6 show the equipment configuration at the demonstration site. A load dump radiator was included with the equipment to permit operation of the system during periods when the building load was low, and to baseload the system for full load operation.

During the demonstration, the system was operated for over 700 hours, with approximately 550 hours of coal water slurry-firing. Table 4.3 summarizes the system operation.

4.2 SYSTEM PERFORMANCE

The system performance goals for space and water heating requirements of commercial buildings are listed below:

Ignition	Fully automatic startup with system purge and ignition verification
Turndown Ratio	3:1
Reliability/Safety	Comparable to oil-fired commercial boilers
Thermal Efficiency	>80%
Combustion Efficiency	>99%
Routine Operating/ Maintenance Labor	Less than one dedicated man-hour per day and an additional two man-hours per week
Ash Removal	Dust-free and automatic or semiautomatic
Scheduled Maintenance	$\leq$ twice a year
Service Life	Overall system $\geq$ 20 years
Emissions	1.2 lb $SO_2/10^6$ Btu 0.3 lb $NO_x/10^6$ Btu 0.03 lb particulates/10^6 Btu

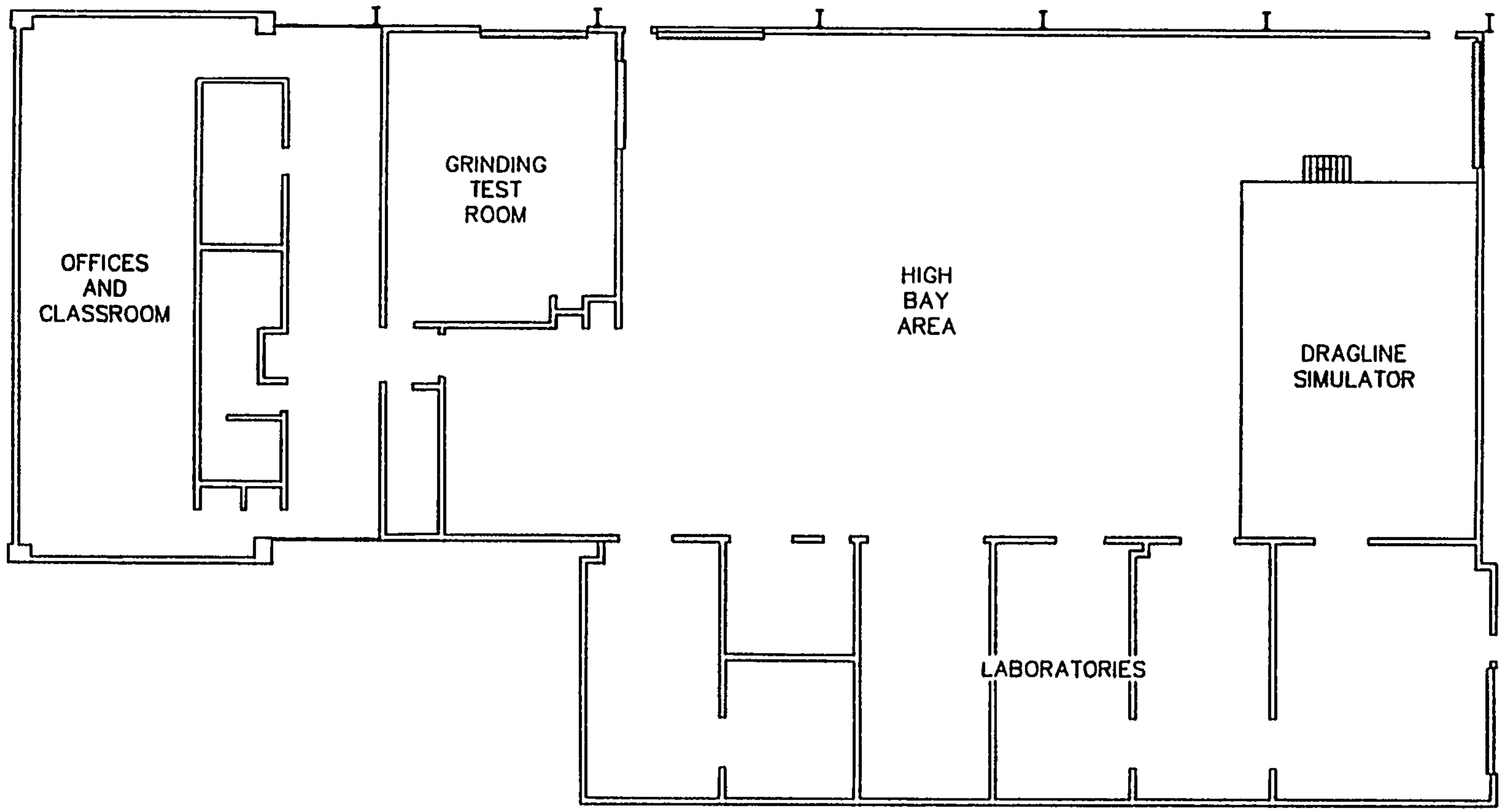

Figure 4.4 High Bay Building Layout

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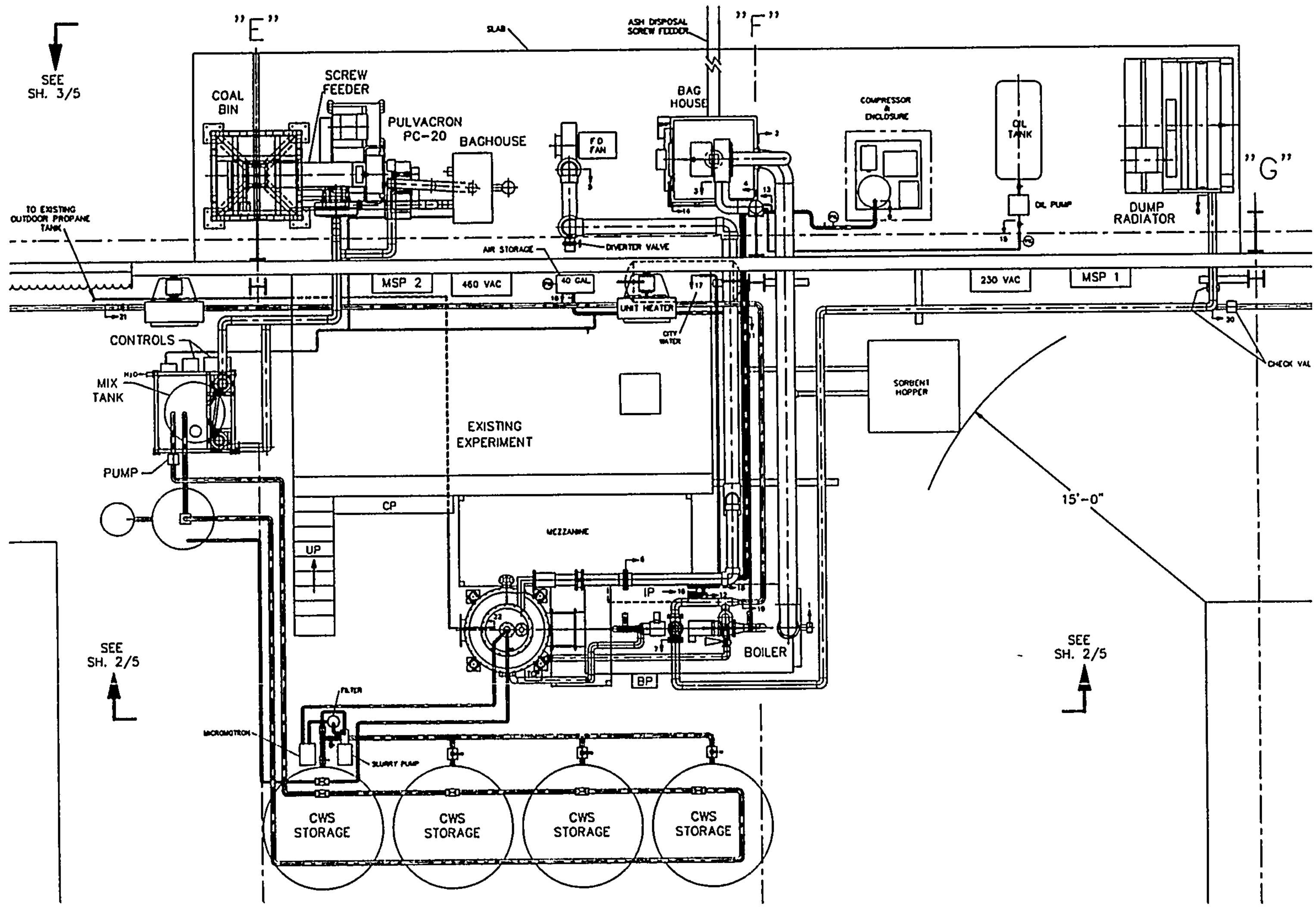

Figure 4.5 Equipment Configuration at Demonstration Site

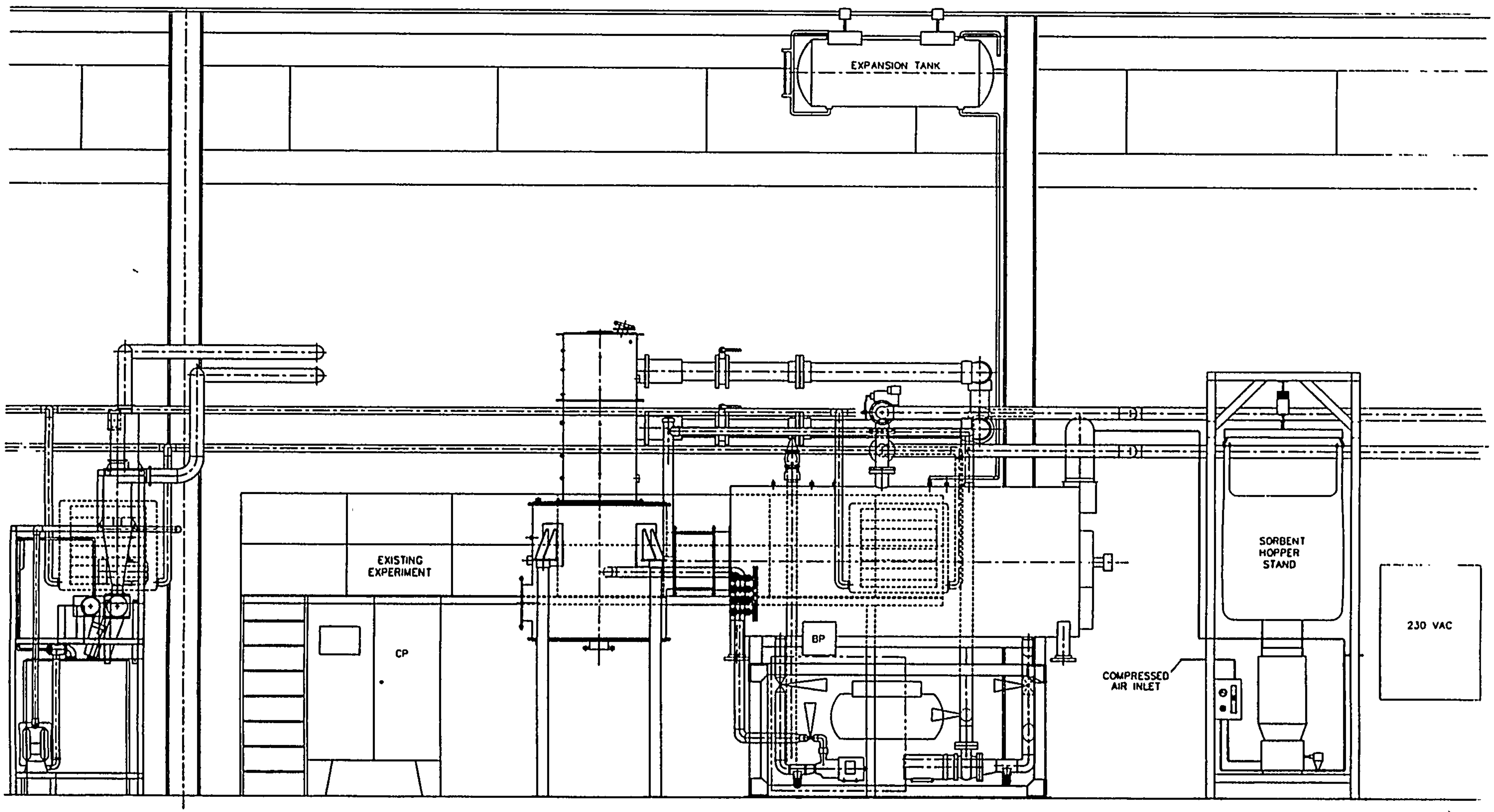

Figure 4.6 Equipment Configuration at Demonstration Site

TABLE 4.3

DEMONSTRATION OPERATION SUMMARY

Date	Length of Operation (Hours)	Length of Slurry Firing (%)	Coal
July			
Shakedown Testing	60	0	
August			
Shakedown Testing	24	33	Kentucky Hazard
27	12	50	Illinois 5 Wabash
30	10	80	Illinois 5 Wabash
31	12	80	Illinois 5 Wabash
September			
2	16	87	Illinois 5 Wabash
3	15	80	Illinois 5 Wabash
6	10	70	Illinois 5 Wabash
October			
19	10	80	Illinois 5 Wabash
November			
2	12	83	Illinois 5 Wabash
3	12	75	"
5	18	88	"
6	20	90	"
7	22	90	"
8	17	88	"
9	18	60	"
10	16	94	"
11	11	100	"
15	24	92	"
16	4	100	"
17	9	88	"
19	8	87	"
22	16	81	"
23	9	83	"
30	24	92	"
December			
1	11	91	Illinois 5 Wabash
2	21	95	"
3	11	100	"
5	8	83	"
13	23	91	"
14	10	100	"
15	22	95	"
16	15	95	"
17	18	89	"
18	12	80	"
20	17	88	"
21	6	60	"
March			
2	8	20	Illinois 5 Wabash
3	10	87	"
11	5	80	"
14	8	75	"
16	12	92	"
17	21	95	"
18	19	89	"
19	5	10	"
22	24	92	"
23	18	89	"
29	5	30	"
30	15	93	"
Total	733 Hrs	560 Hrs	

There are wide variations in state and local air pollution control regulations for commercial scale space heating systems. In addition, these regulations are all subject to change. Therefore, the abovementioned emissions specifications chosen as the program goals by the DOE are those that are expected to be achieved based on the present state of development of coal cleaning, combustion, and flue gas cleanup technologies. These goals are consistent with Title IV of the Clean Air Act Amendments of 1990, which will limit SO_2 emissions to 1.2 lbs/MMBtu, and NO_x emissions to between 0.45 and 0.5 lbs/MMBtu from coal-fired utility boilers. For coal-fired systems to become environmentally, and hence commercially acceptable, for this market sector however, emissions levels will ultimately need to be comparable to those produced by fuel oil-fired commercial scale units, which are:

0.4 lb $SO_2/10^6$ Btu, 0.2 lb $NO_x/10^6$ Btu, and 0.02 lb particulates/10^6 Btu.

In designing the emissions control strategy for the system and evaluating system performance, close attention was paid to the likelihood that the emission levels from the system may need to be lower than those of the program goals. Fabric filter particulate control devices can generally achieve the lower particulate emissions and, through increased sorbent injection and residence times, the lower sulfur emissions can be met with the duct injection process. As shown in Section 4.2.2, NO_X levels of 0.2 lb/$NO_2/10^6$ Btu can be met with the CWS combustor.

Following is a discussion of the system performance as related to the system performance goals. Since system performance in general and emissions in particular are both dependent on coal properties, variations in system performance encountered with each of the three coals utilized are addressed.

4.2.1 Ignition

The combustion system has been successfully ignited over 300 times without incident. For laboratory testing, the system was ignited with a natural gas pilot, and during demonstration site operation, propane was utilized. The pilot consists of a Honeywell Flame Safeguard System with an ultraviolet flame sensor. The pilot is interlocked with the fuel to ensure safe operation. A second safety interlock is triggered by combustion chamber temperature. Once fuel is introduced to the combustor, if the combustion chamber temperature does not reach a pre-set temperature in the prescribed time period, the fuel flow will automatically be stopped. In addition, fuel flow will be interrupted whenever the combustor temperature drops below this value. Before re-starting the system, a purge sequence is automatically initiated. The pilot can be operated on either a continuous or intermittent basis.

From a cold start, the system is operated on fuel oil for approximately 1 hour at a firing rate of 1.5 MMBtu/hr to bring the boiler water up to temperature (165°F) and the baghouse temperature above the dew point before switching to slurry. With the boiler water at temperature, fuel switchover can occur in approximately 15 minutes. Switchover is accomplished by bringing on the CWS at a preselected low fire level and, after a prescribed period of cofiring, the fuel oil is shut off as the slurry is increased to meet the system thermal requirements.

4.2.2 Combustor

System tests performed during the component development stage of the program revealed that material accumulation in the combustor occurred during prolonged combustor operation at high loads. During the POC tests, several design modifications were implemented to eliminate this material accumulation. The final combustor configuration resulted from a thorough investigation of design and operating parameters including: combustor wall material, partition location and size, atomizer spray angle, and combustion air staging. The combustor design evolution was influenced strongly by the need to burn progressively higher ash coals with changing ash properties. Table 4.4 gives the ash fusion temperatures for the three coals.

Figures 4.7 through 4.11 illustrate the progression of changes made to the internal combustor geometry. Although refractory surfaces could be used in the lower regions of the combustor when burning the high ash fusion temperature Kentucky coal, ash attachment to the refractory surfaces was problematic for the lower fusion temperature Illinois coals. Best results were obtained with all three coals, with metal liners and water-cooled partitions making up the combustor internal surfaces. Various arrangements were investigated to control metal liner temperatures, while at the same time controlling heat extraction from the combustor and allowing for liner growth. The final arrangement, as shown in the combustor sketches, is to allow the liners to operate as floating shields. In this configuration, rather than having a refractory material between the liner and water-cooled shell, and controlling liner temperature through conduction, the liner is offset from the water-cooled shell by a quarter inch air gap and is allowed to radiate back to the shell. This configuration allows for unrestrained circumferential expansion of the liner and eliminates the possibility of hot spots, which can develop if the liner separates from the refractory in the contact arrangement.

Initially, combustor liners were made using Type 310 Stainless Steel. POC testing revealed significant metal corrosion however, and the liner material was upgraded to a high temperature alloy manufactured by Rolled Alloys, RA85H. This material contains 61% iron, 18.5% chromium, 14.5% nickel, and small percentages of silicon, aluminum, and manganese for high temperature strength, thermal fatigue resistance, and resistance to carburization. All liners, including the roof liner, are 1/4" thick for added strength and distortion resistance.

In addition to eliminating material accumulation in the combustor, the combustor modifications also resulted in a reduction in the NO_x produced, allowing performance goals to be met. Figure 4.12 shows the reduction in NO_x achieved in going from the baseline refractory lined combustion chamber (Figure 4.7) to the metal lined/water-cooled upper chamber configuration (Figure 4.8). The NO_x reductions realized with the metal liner/water-cooled partition configuration can be attributed to more uniform devolatilization and burning of the coal particles, a reduction in wall temperatures, where the bulk of particle burnout occurs, and a slight reduction in the bulk gas temperature resulting from increased heat extraction. As can be seen in the figure, NO_x emission goals were met over the full range of combustor load.

TABLE 4.4

ASH FUSION TEMPERATURE

	Kentucky		Illinois No. 5		Illinois No. 6	
Fusion Temperature	**Red.**	**Oxid.**	**Red.**	**Oxid.**	**Red.**	**Oxid.**
Initial Deformation	2700+	2700+	2053	2475	2052	2468
Softening	2700+	2700+	2163	2528	2152	2508
Hemispherical	2700+	2700+	2258	2570	2283	2549
Fluid	2700+	2700+	2360	2613	2389	2595
Ash (% Dry)	3.7		7.2 POC 10.3 DEMO		11.7	

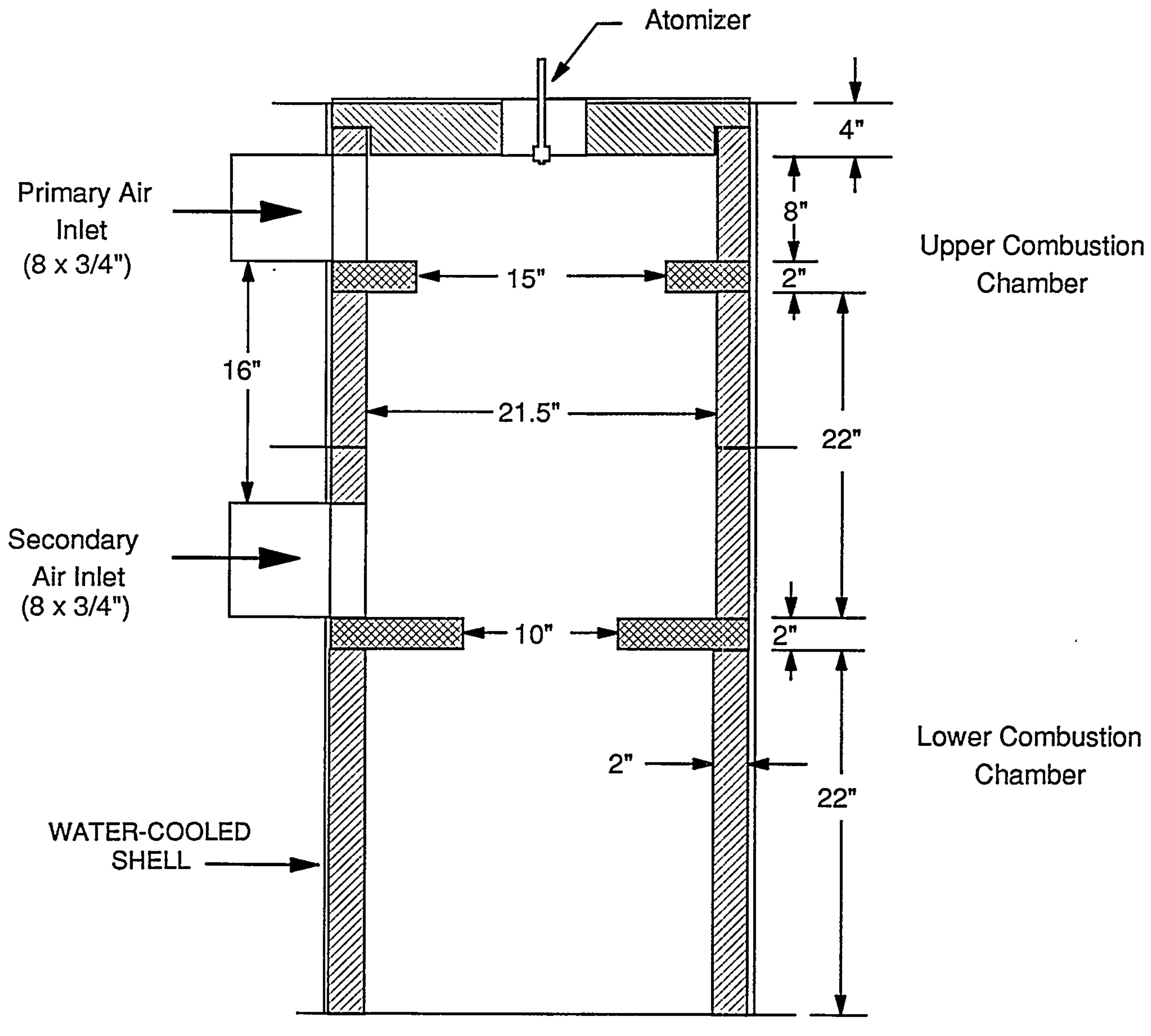

Figure 4.7 Refractory Lined Combustor Configuration

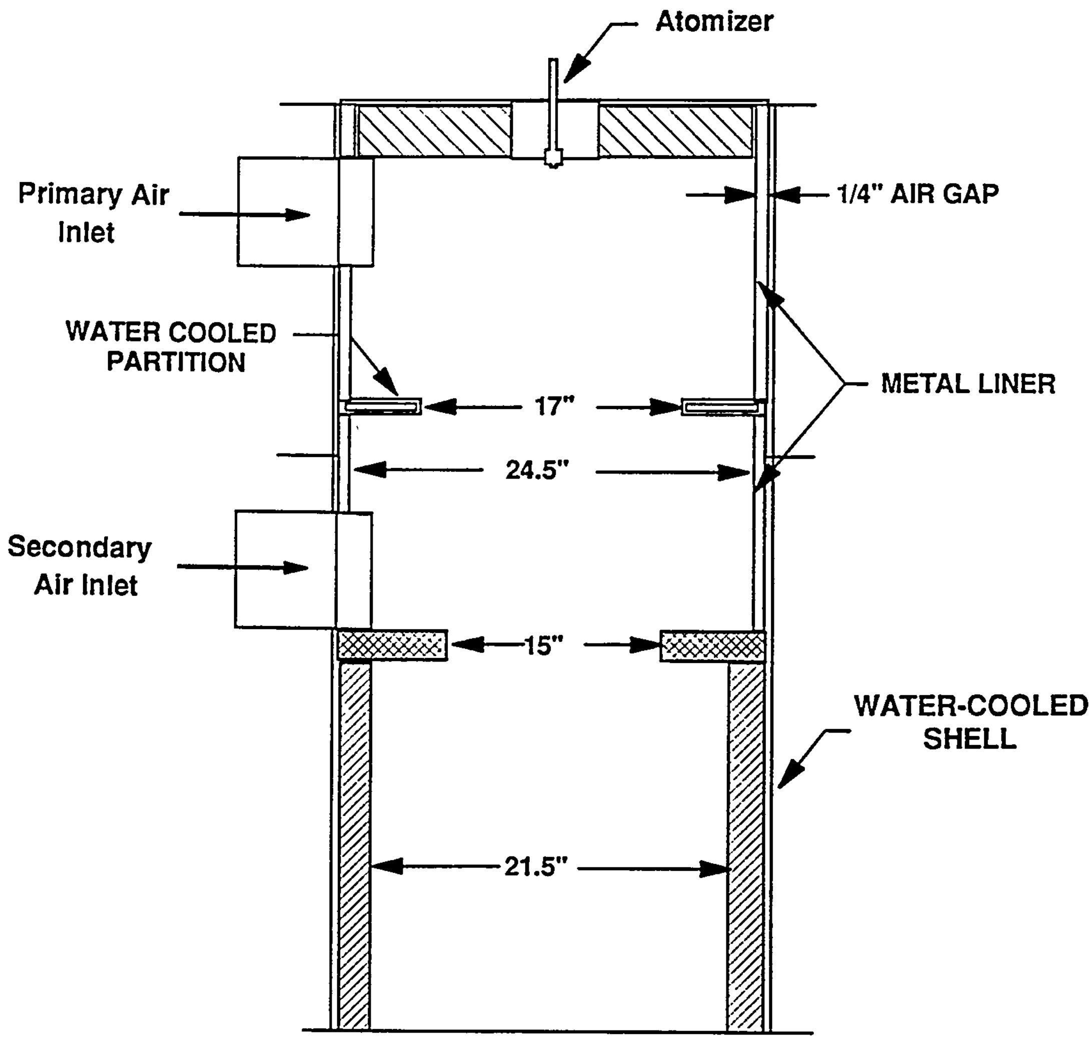

Figure 4.8 Metal Lined/Water Cooled Partition – Upper Chamber Combustion Configuration

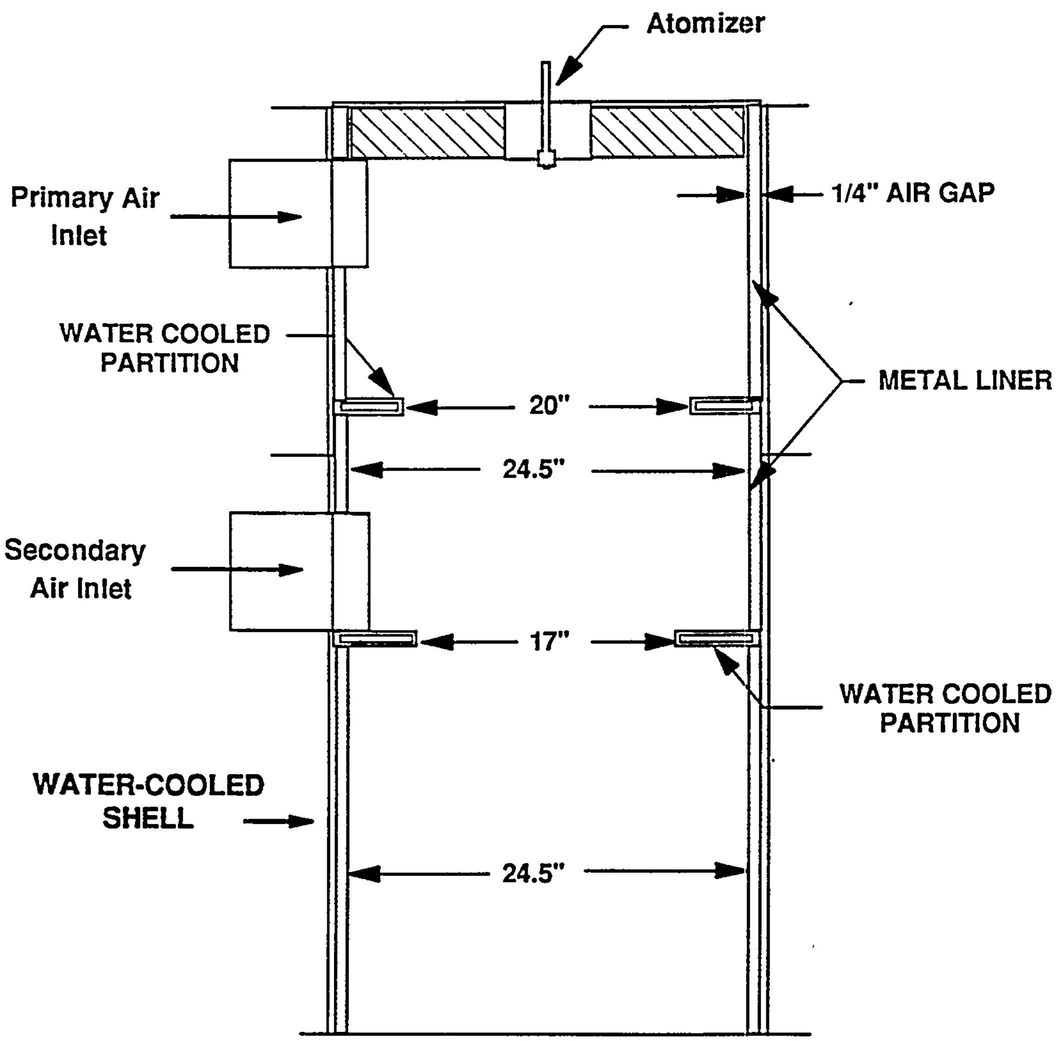

Figure 4.9 Combustor Configuration With Full Length Metal Liner Water Cooled Partitions

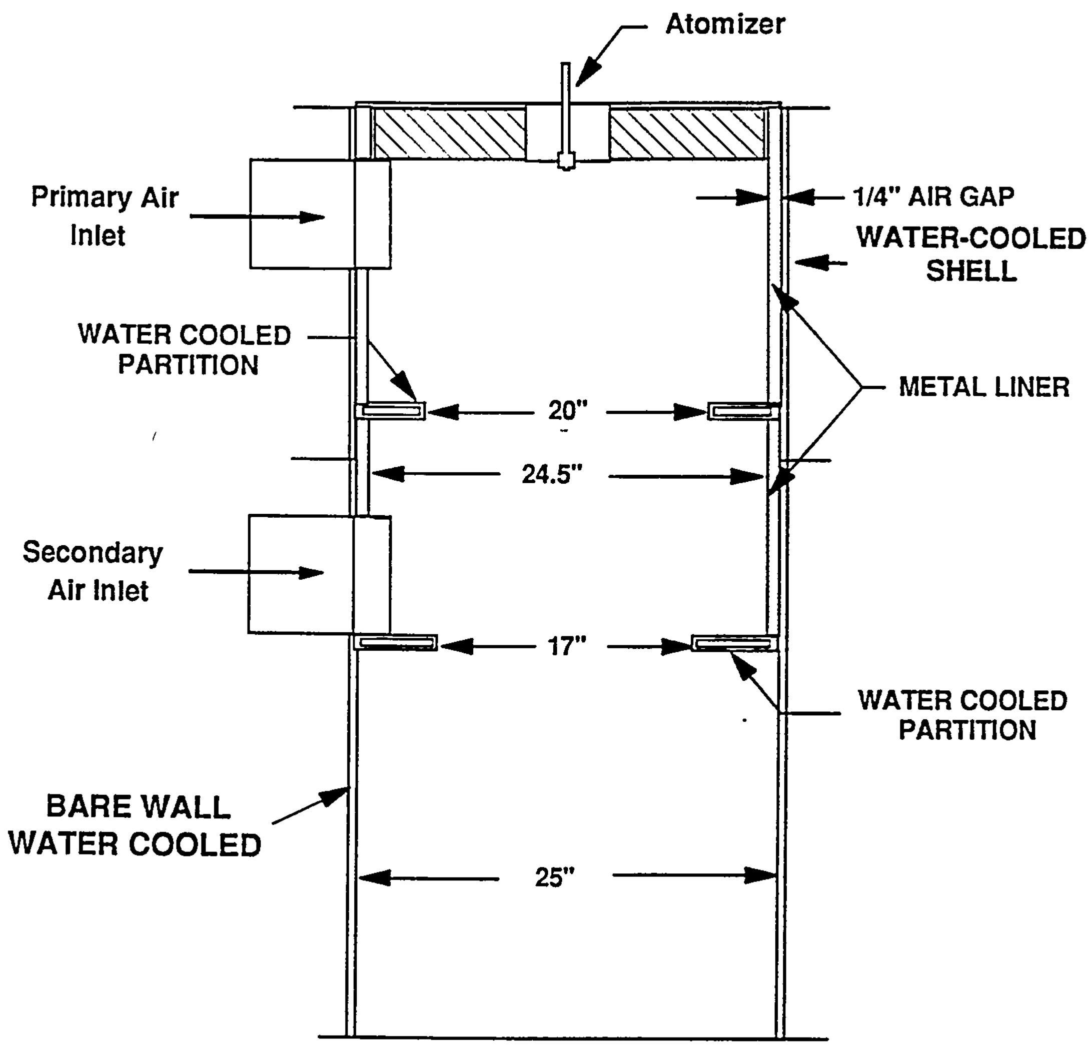

Figure 4.10 Bare Wall – Water Cooled Lower Combustor

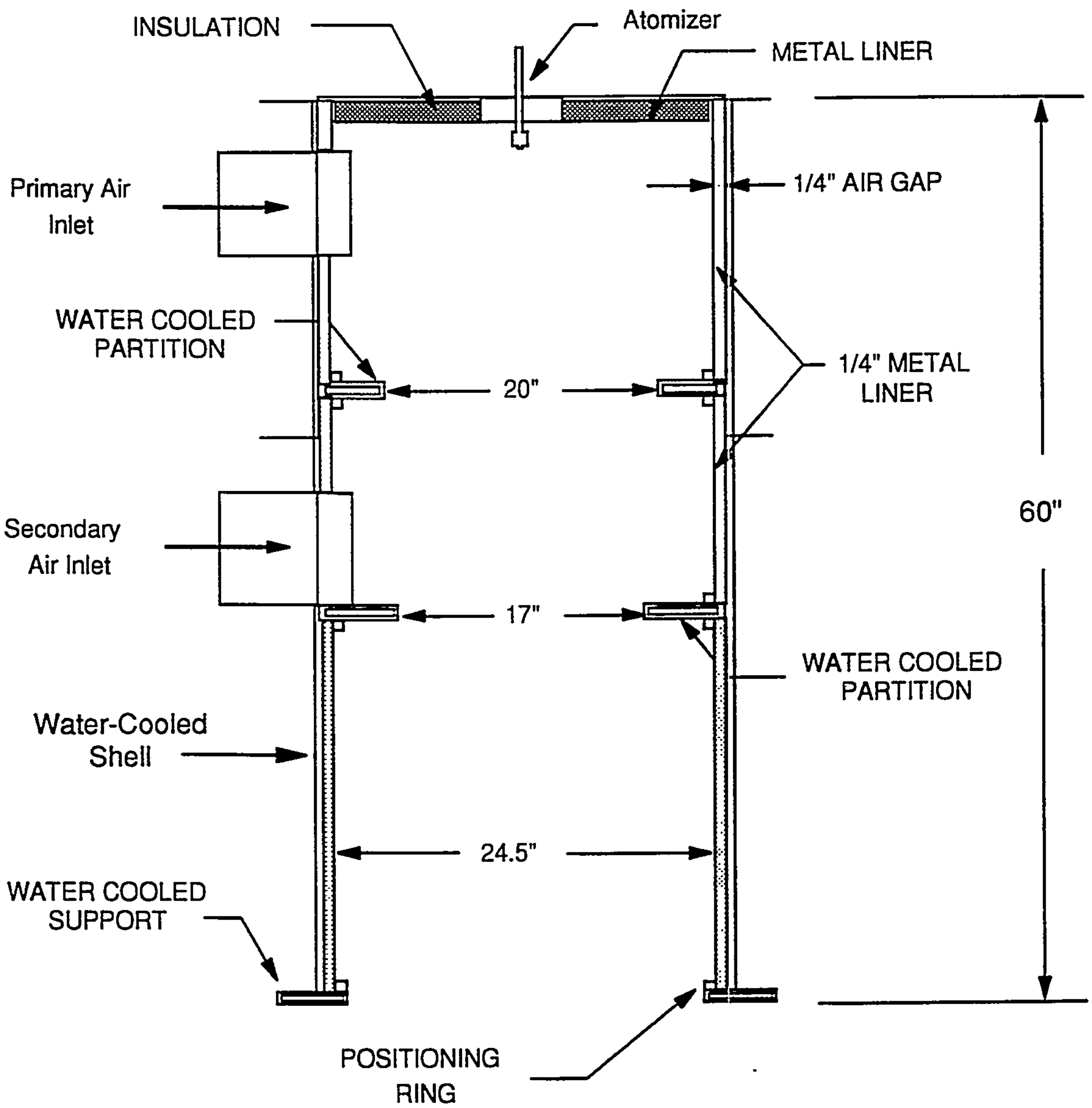

Figure 4.11 Combustor Configuration With Metal Roof Liner

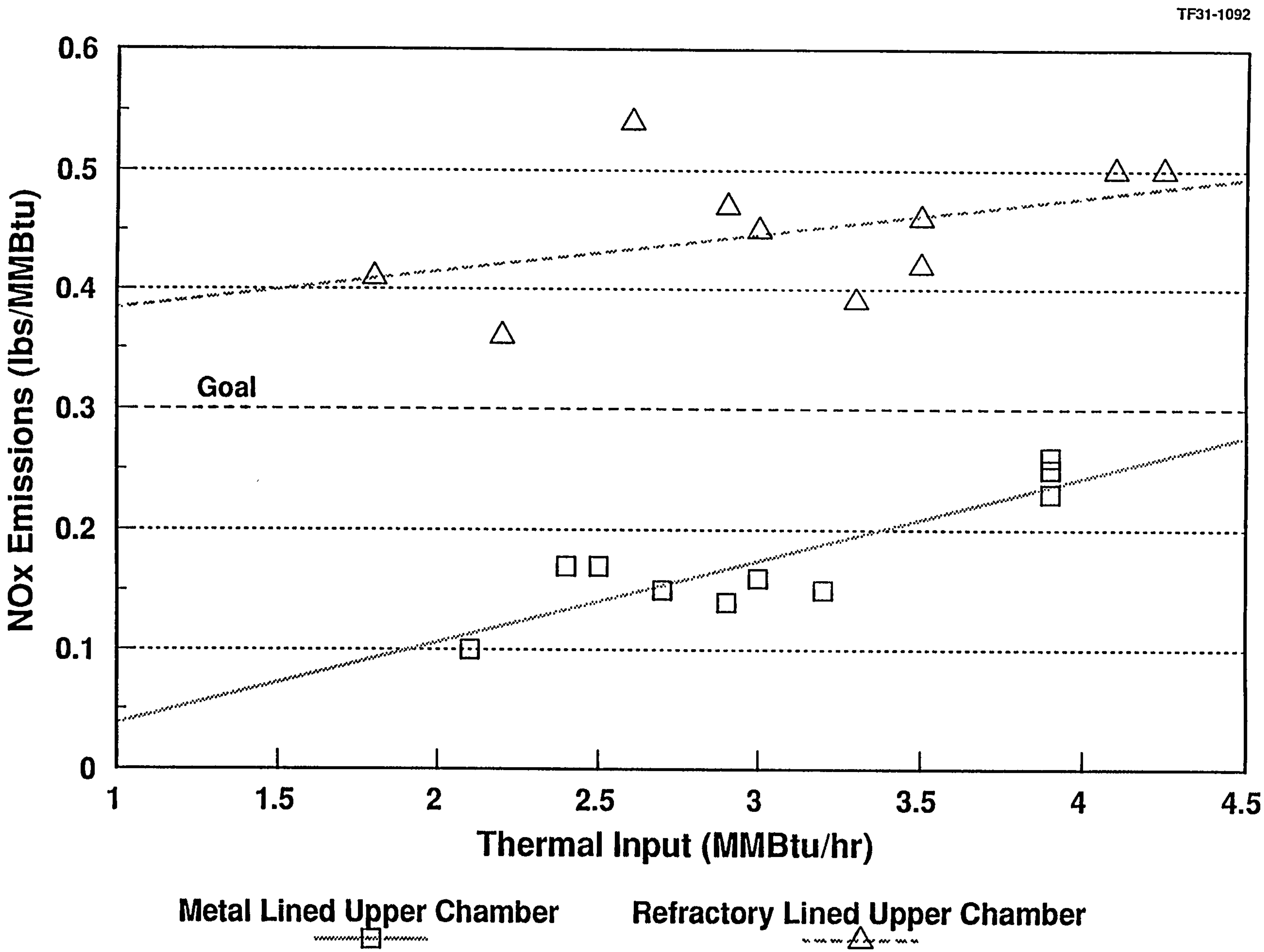

Figure 4.12 NO_x Emissions With Refractory and Metal Lined Upper Combustor Chamber Kentucky CWS

When Illinois CWS was burned in the metal liner/water-cooled partition upper chamber configuration (Figure 4.8), NO_x formation, as shown in Figure 4.13, was greater than that for the Kentucky CWS as shown in Figure 4.12. This higher NO_x formation was a result of material deposition on the remaining refractory within the combustor. Whereas the Kentucky coal with an ash fusion temperature in excess of 2700°F did not stick to this refractory, the lower fusion temperature Illinois coal readily attached to these surfaces. To eliminate this material accumulation and also reduce NO_x, the lower chamber refractory was replaced with a metal liner and water-cooled partition similar to that utilized in the upper combustion chamber.

This arrangement reduced the material accumulation on the lower chamber walls, but did not entirely eliminate it, and, as a result, NO_x formation was only slightly reduced (see Figure 4.13). Oxidation of the stainless steel liner in the lower chamber was partly responsible for the ability of the ash to attach itself rather tenaciously to the lower liner walls, resulting in wall burning.

The third set of data on Figure 4.13 shows the NO_x levels for the combustor configuration of Figure 4.10. This configuration, with water-cooled metal surfaces below the lower partition, entirely eliminated material accumulation in the lower combustor and also significantly reduced NO_x formation. The performance goal of 0.3 lbs NO_x per MMBtu was achieved throughout the entire load range.

For the refractory lined combustor, combustion efficiencies greater than 99% were achieved while burning Kentucky CWS. Combustion efficiencies for the various deposition management combustor configurations utilizing Illinois No. 5 CWS are given in Table 4.5. There was a slight drop in combustion efficiency from the baseline, refractory lined, combustor configuration. This reduction can be attributed to the lower heating value of the Illinois CWS and to the slightly lower bulk temperature in these configurations due to the additional heat extraction. Table 4.6 summarizes the heat extraction data for the different configurations.

For the final combustor configuration, Figure 4.11, utilized during demonstration operation, NO_x levels (see Figure 4.13) were similar to those achieved with the water-cooled metal surface configuration. This result can be primarily attributed to the reduction of material accumulation in the combustor due to the change in the combustor wall materials, and also a change in the combustor operation, wherein periodic automatic cleaning was implemented. Combustion efficiencies were in line with those obtained with the similar metal lined configuration utilized during POC testing. Figure 4.14 shows representative combustion efficiencies achieved during the course of the demonstration testing. As discussed in the subsequent section on ash management, approximately 25% of the coal ash was collected in the transition chamber. Combustion efficiencies were effected by a number of process variables, including primary zone stoichiometry, overall stoichiometry, thermal input, and slurry properties. In general, overall combustion efficiencies of 96 and 99% were maintained.

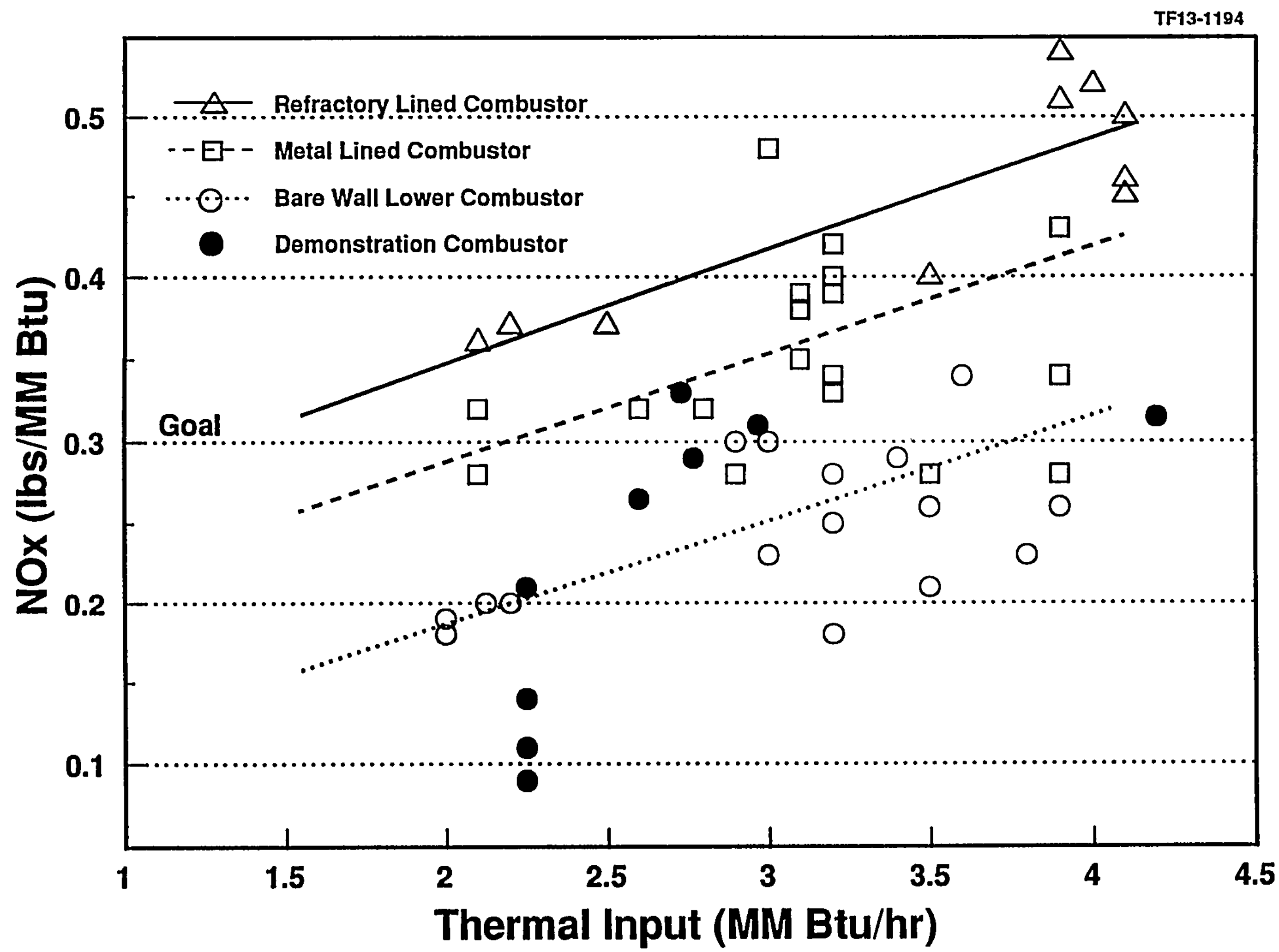

Figure 4.13 NO_x Emissions With Illinois Coals

TABLE 4.5

COMBUSTION EFFICIENCIES FOR THE VARIOUS DEPOSITION MANAGEMENT COMBUSTOR CONFIGURATIONS UTILIZING ILLINOIS NO. 5

	Refractory Lower Chamber			Metal Lined Lower Chamber				Bare Wall Lower Chamber		Transition Chamber Deposit
Run Date Thermal Input	7/16/92 4.0 MM	7/16/92 2.5 MM	7/16/92 4.0 MM	8/5/92 3.0 MM	9/2/92 2.7 MM	9/3/92 3.2 MM	9/10/92 3.6 MM	9/15/92 2.6 MM	9/16/92 3.5 MM	
Combustion Efficiency	98.7	98.7	98.0	99.6	96.3	98.8	97.3	96.8	97.7	100.0

TABLE 4.6

COMBUSTOR/TRANSITION CHAMBER HEAT EXTRACTION (Btu/hr)

Configuration	A Refractory Lined Combustor	B Refractory Lined Lower Combustor	C Metal Lined Lower Combustor	D Bare Wall Lower Combustor
Upper Chamber	127,000	204,000*	183,000*	115,000*
Lower Chamber	212,000	156,000	309,000*	620,000*
COMBUSTOR TOTAL	339,000	444,000	492,000	735,000
Transition Chamber	260,000	250,000	230,000	240,000
TOTAL	599,000	694,000	722,000	975,000
TOTAL (% FULL LOAD INPUT)	**15.0**	**17.3**	**18.0**	**24.4**

*Includes water-cooled partition.

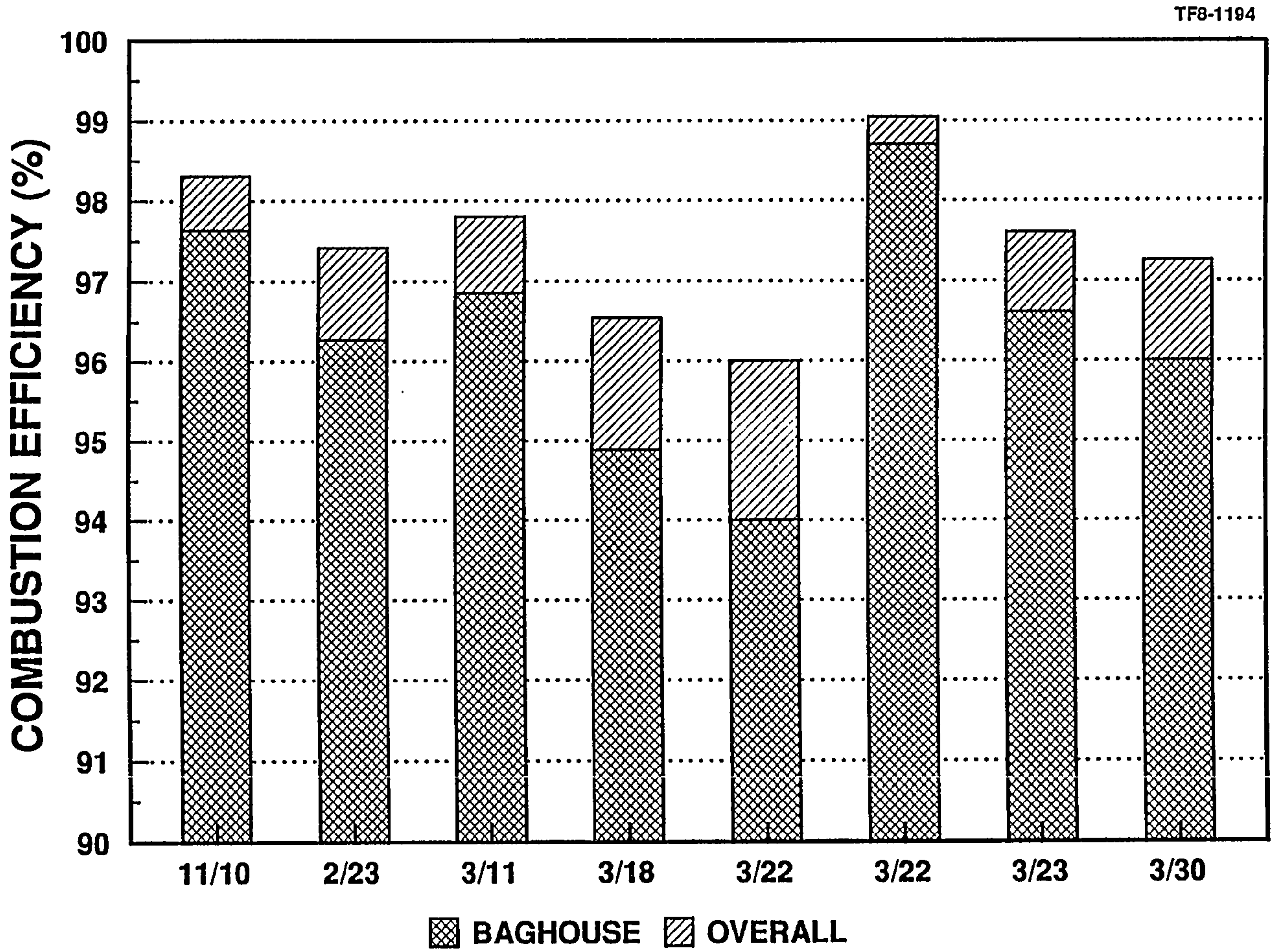

Figure 4.14 Combustion Efficiency During Demonstration Operation

4.2.3 Boiler

As discussed in Section 2.2.2, initial testing with the boiler revealed the need for on-line cleaning of the boiler heat transfer surfaces. A compressed air soot blower system was, therefore, installed. Figure 4.15 is a plot of the boiler exit temperature with and without the soot blowing system and Figure 4.16 shows the boiler exit temperature as a function of load and operating hours. These curves clearly show the effectiveness of the soot blowing system in keeping the tubes clean.

One area which is not covered by the soot blowing system and is prone to ash deposition is the entrance to the boiler. Figure 4.17 is a schematic of the Transition Chamber/Boiler Connection configuration with and without a refractory liner used to control ash deposition. A drawing of the revamped unit would be more useful. Ash deposition onto the refractory surfaces in this area, although not sufficient to impact system performance for the length of tests conducted during the POC testing, was projected to limit the long term commercial operation. To minimize the deposition in this region and to ensure that the deposits, if any, can be easily removed, a liner of RA85H was added to this region, extending slightly inward of the transition chamber refractory and slightly beyond the boiler morrison tube refractory.

The boiler tubes remained free of ash build up throughout the demonstration operation and no corrosion or erosion of the boiler tube sheets or tubes has been detected.

4.2.4 Emissions Controls

Unregulated SO_2 emissions for the Kentucky Hazard, Illinois No. 5, and Illinois No. 6 coals are 1.0, 2.4, and 4.9 lbs/MMBtu, respectively. Corresponding uncontrolled particulate emissions for these coals are 2.5, 5.4, and 9.1 lbs/MMBtu, assuming that all ash is entrained in the flue gas.

The ability to control SO_2 emissions levels below the performance goal of 1.2 lbs/MMBtu was demonstrated for the Illinois coals. Since the Kentucky coal is a compliance coal as far as sulfur emissions are concerned, sulfur removal from the exhaust gas was not necessary. Figure 4.18 shows a typical plot of SO_2 emissions for Illinois No. 5. SO_2 emissions were reduced to below the design goal at a sodium to sulfur stoichiometric ratio of approximately 0.65. A similar plot for Illinois No. 6 operation is given in Figure 4.19.

As discussed in Section 2.2.4, particulate emissions are controlled through the use of a conventional pulse jet baghouse filter. The performance goal of 0.03 lbs/MMBtu is well within the performance specifications of the Flex Kleen unit and fabric filters in general. For the ash and sorbent particle sizes encountered, the manufacturer, based on historical design data and operating experience, guarantees an exit dust loading of 0.013 grains per standard cubic foot throughout the operating range of the system. Table 4.7 summarizes the operating conditions for both average (3 MMBtu/hr) and maximum design conditions (5 MMBtu/hr).

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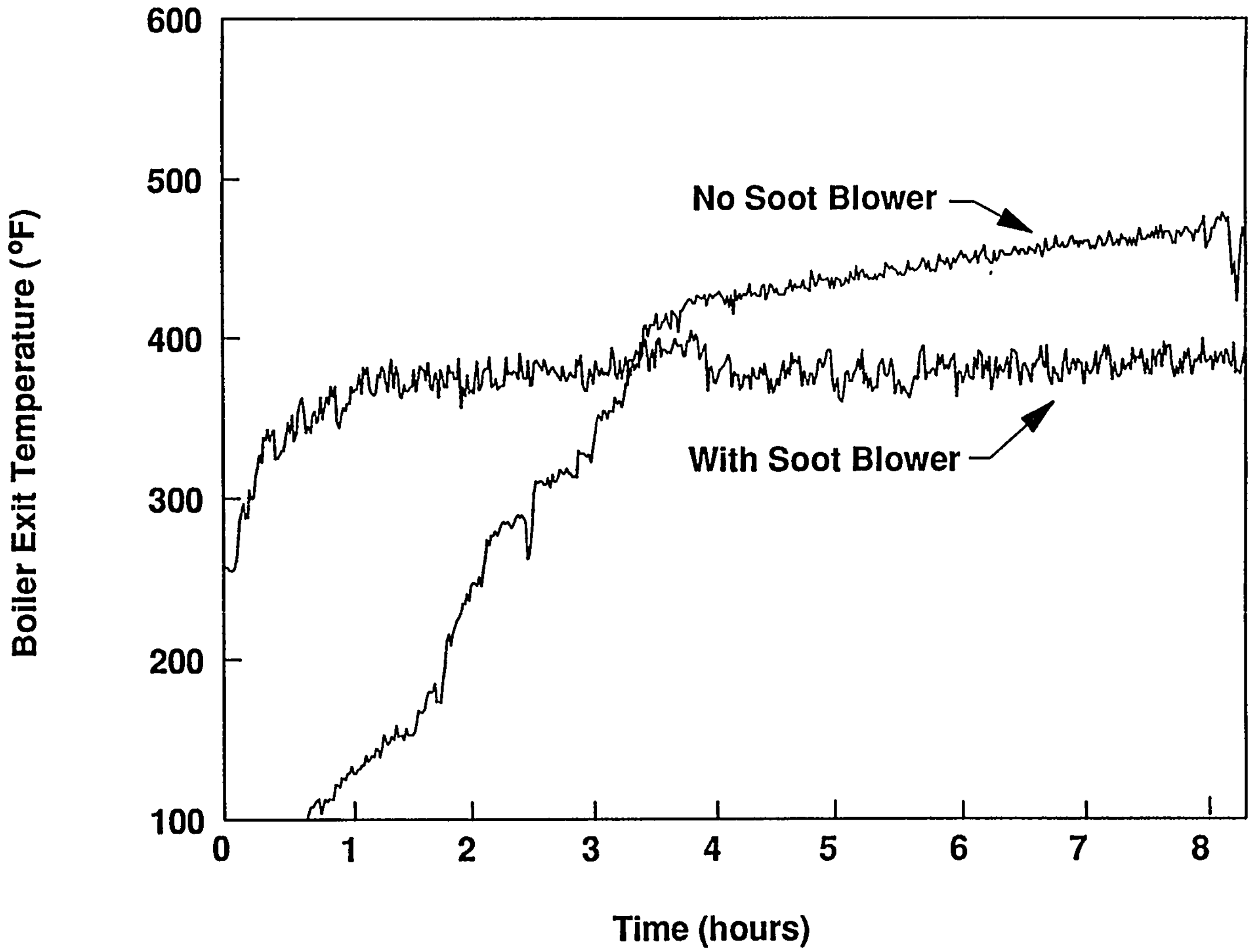

Figure 4.15 Boiler Exit Temperature

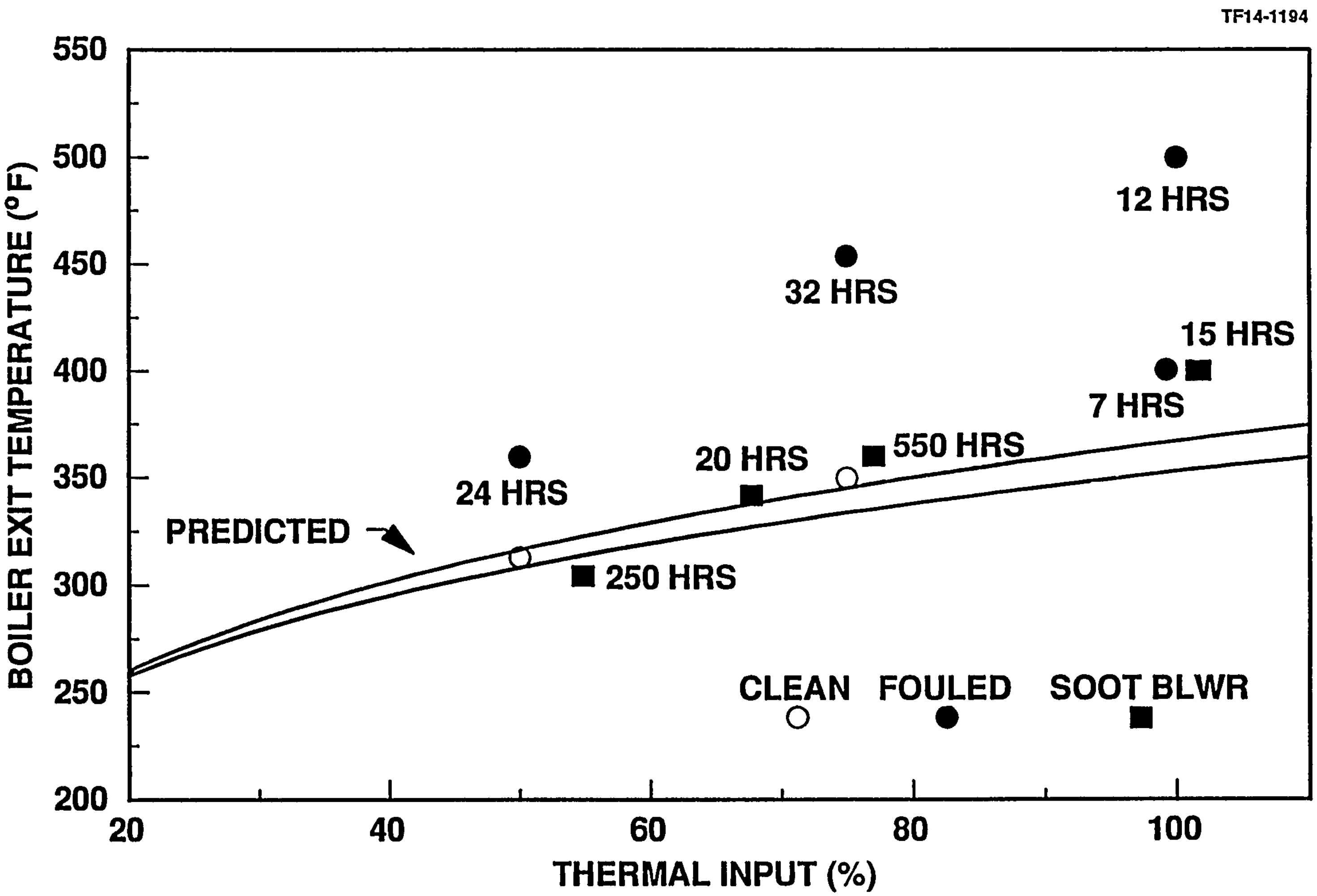

Figure 4.16 Boiler Performance

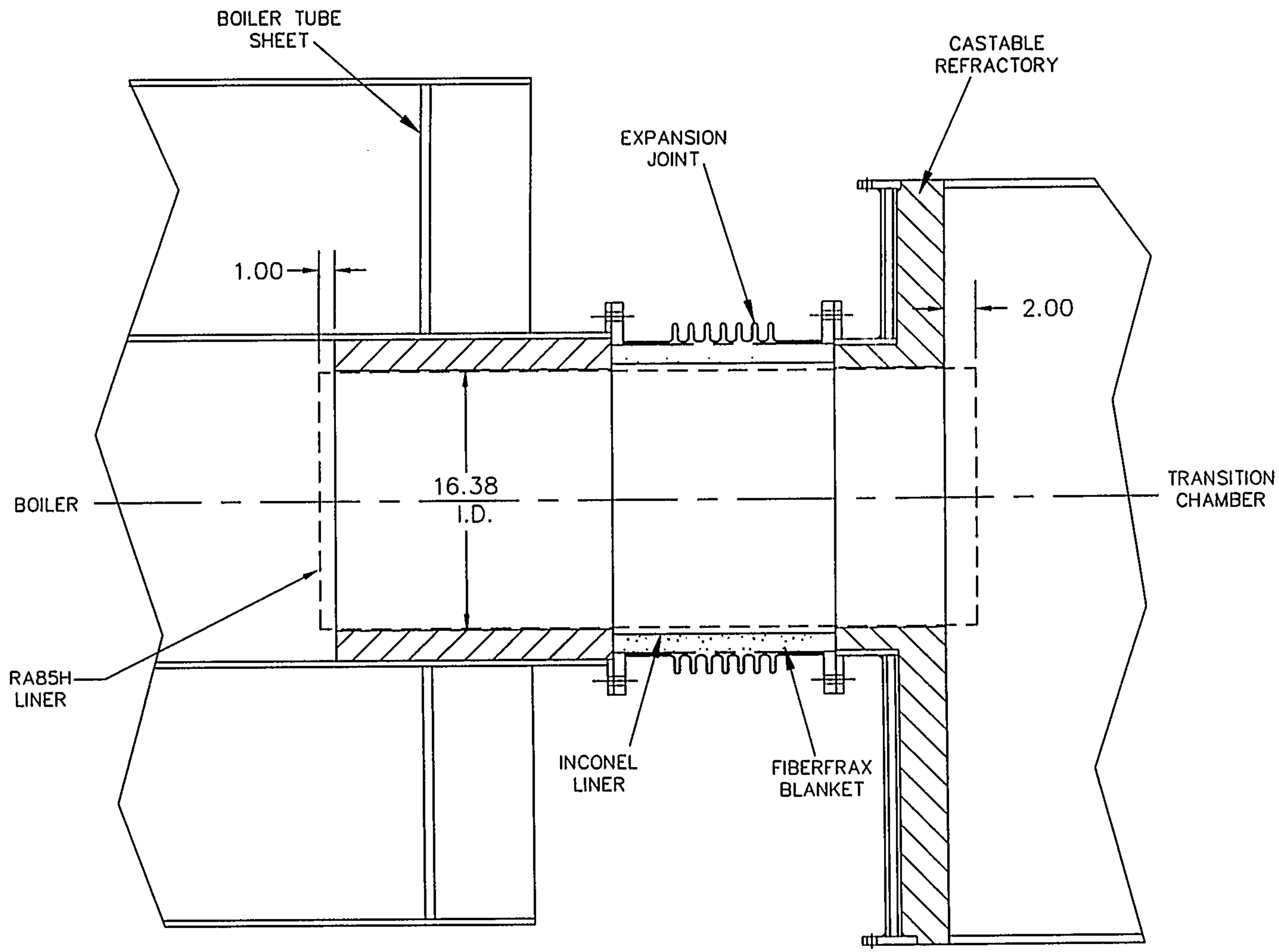

Figure 4.17 Transition Chamber/Boiler Connection (Refractory Lined) (RA85H Liner Shown in Dashed Line)

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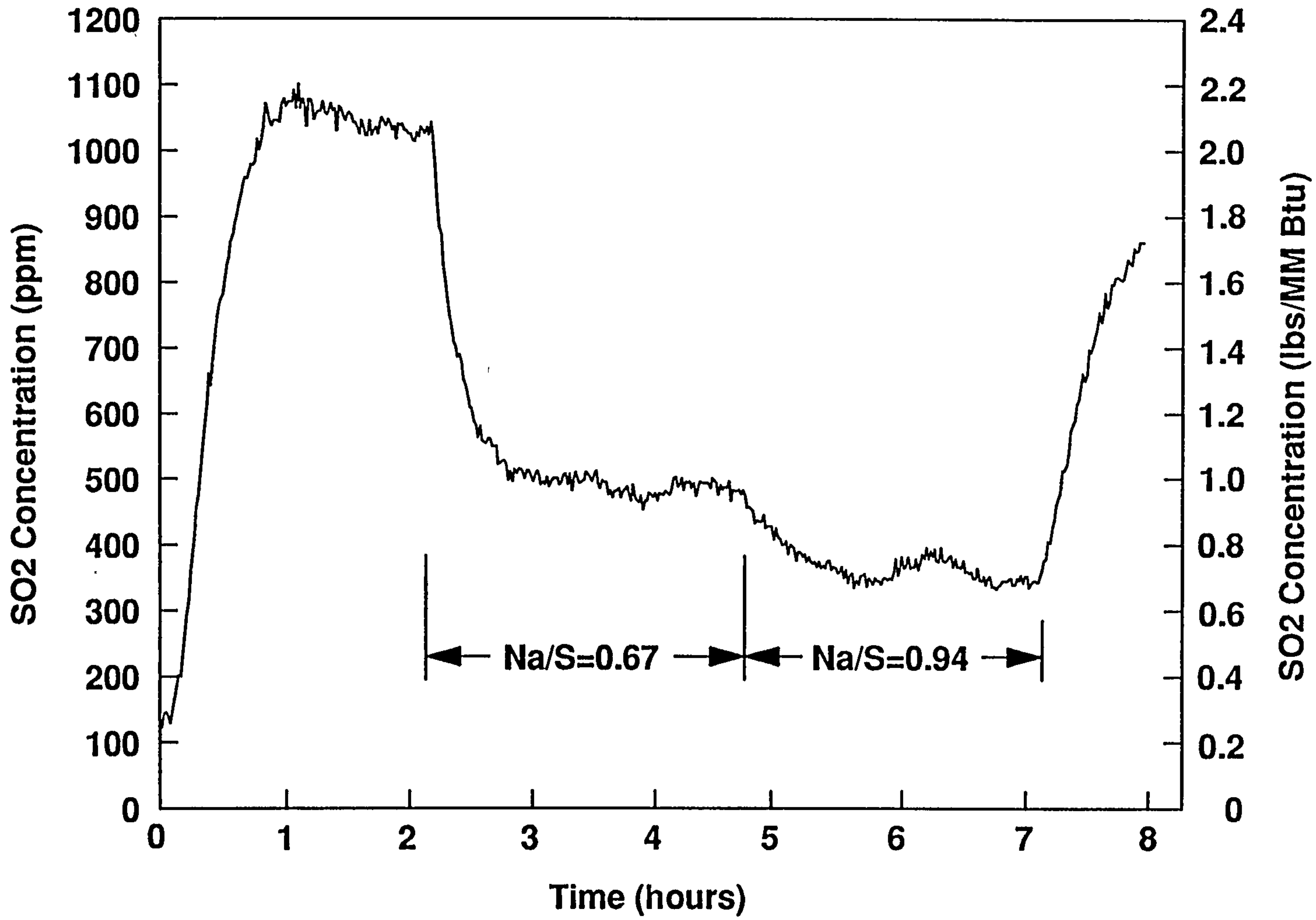

Figure 4.18 SO_2 Concentration at Baghouse Exit – Illinois No. 5 CWS

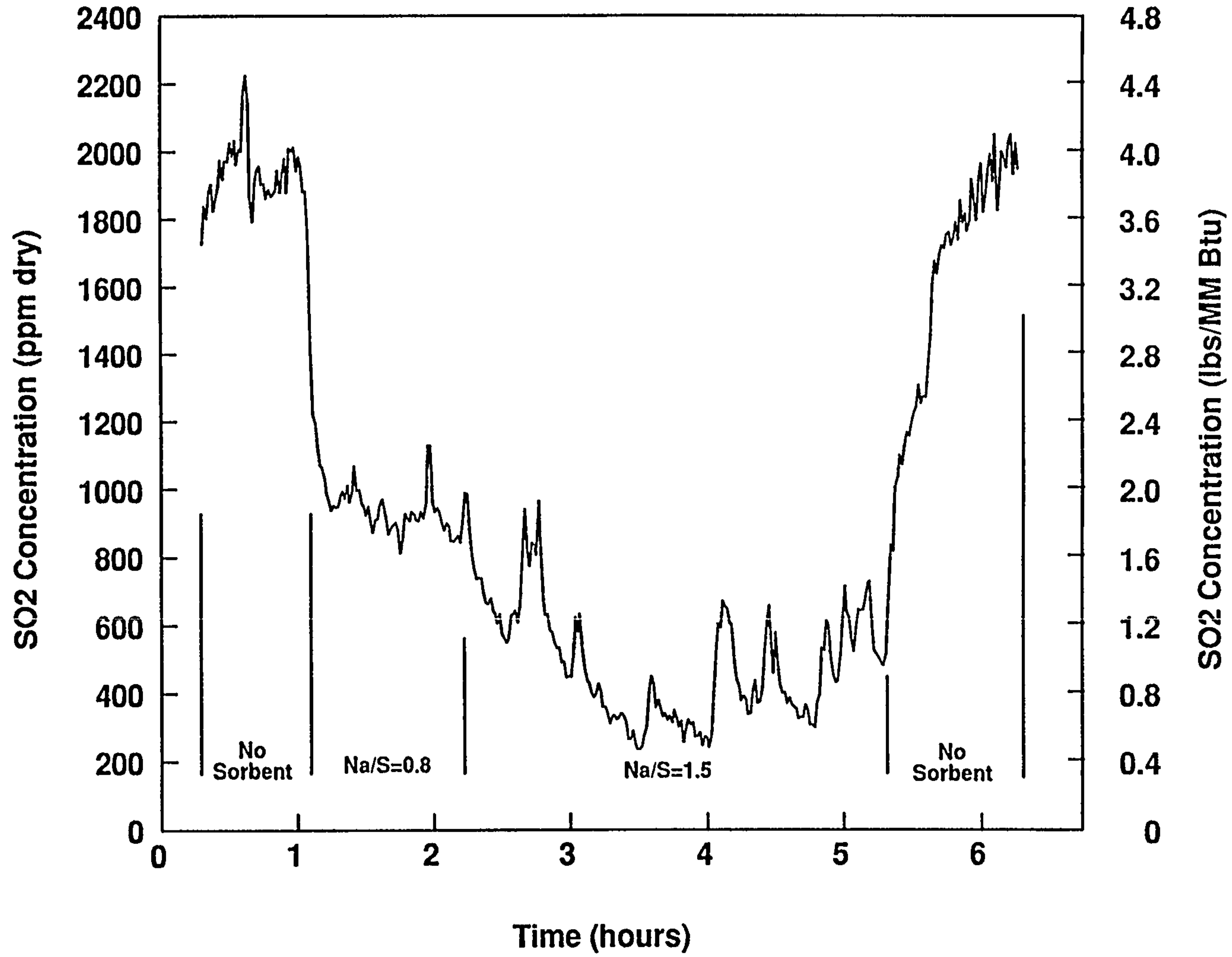

Figure 4.19 SO_2 Emissions With Illinois No. 6 CWS

TABLE 4.7

PROJECTED OPERATING CONDITIONS FOR AVERAGE AND MAXIMUM FIRE CONDITIONS

Thermal Input	Average	Maximum
Inlet Temperature (°F)	375	425
Inlet Gas Flow (acfm)	1136	2022
Inlet Dust Flow (lbs/hr)	47	80
Air to Cloth Ratio	2.49	4.4
Inlet Gas Loading (gr/scf)	7.75	7.86
Outlet Gas Loading (gr/scf)	0.013	0.013
Outlet Dust Flow (lbs/hr)	0.079	0.132
Capture Efficiency	99.83	99.84

4.2.5 Ash Management

During the course of the development program, a significant amount of attention was paid to eliminating ash/char accumulation in the combustor, especially when burning low ash fusion temperature coals. Although significant reductions were achieved through the combustor and atomizer designs and subsequent modifications, during periods of prolonged operation, gradual accumulation of ash/char deposits would eventually degrade combustor performance if left untreated. To counteract this, the control software was configured to shut down the slurry flow momentarily to allow for self-cleaning of the combustor through thermal cycling and air sweeping of any material accumulation. The system is then automatically restarted with fuel oil and, once temperatures are re-established, slurry firing is resumed. The entire procedure lasts approximately 15 minutes and is initiated every six hours.

This periodic combustor self-cleaning, along with continuous drop out of large agglomerated ash, does result in ash accumulation in the transition chamber, which during the demonstration operation limited the amount of continuous operation of the system. With the relatively high ash (10 to 13 wt. % ash) Illinois No. 5 coal utilized during the demonstration, the transition chamber had to be cleaned out approximately every 48 hours of operation. Approximately 25% of the total coal ash is collected in the transition chamber, and, in the current transition chamber configuration, it requires approximately 2 hours of system shutdown to manually remove this material from the chamber.

Several concepts have been developed to provide for on-line removal of ash from the transition chamber, but program resources were not sufficient to permit implementation. The simplest of these concepts would be to modify the transition chamber bottom to allow ash discharge into a collection container during combustor operation. Since the ash collected in the transition chamber is agglomerated and not readily free flowing, the bottom opening must be sufficiently large to permit drop-out of the material. An alternate approach is to install a mechanical device to break up the agglomerated ash at the base and pneumatically convey the ash directly to baghouse, where it can be conveyed to the ash container by the baghouse screw conveyor.

4.2.6 Miscellaneous Hardware/Operational Improvements

In addition to the hardware and operational changes described above and the normal types of adjustments and fixes associated with new equipment and system start-up and shakedown, several additional hardware/operational improvements were made to the combustion system and associated equipment during the course of the demonstration operation. These are discussed briefly:

- Pulverizer

During the course of slurry production during laboratory and initial host site demonstration, periodic coal jams at the pulverizer inlet were encountered. To keep up with the demands of the space heating system during continuous operation, which required three slurry batches to be made in an 8 hour period, the pulverizer inlet was enlarged to prevent jams when grinding larger size, higher moisture content coals.

- Slurry Production

At the start of the demonstration operation, slurry properties were found to vary considerably while the fuel was stored in the storage tanks. To maintain proper slurry viscosity, a decrease in coal loading and additional dispersant were necessary. It was found that slurry PH was changing with time, adversely degrading the effectiveness of the dispersant. During the remainder of the demonstration, slurry PH was closely monitored with a hand held PH meter, and the PH was maintained at PH = 8.0 through the addition of ammonium hydroxide.

- Slurry Pump

Excessive wear was encountered in the slurry pump mechanical seal, which led to excessive slurry leakage. This wear was caused by coal particles getting in between the graphite/metal sealing surfaces, resulting in rapid destruction of the graphite sealing ring. The slurry pump was replaced with a similar unit having a packing seal rather than a mechanical seal. The packing seal was adjusted periodically to control leakage from the pump.

- Combustor Head

During the course of demonstration operation, combustor operation changed somewhat suddenly, with higher gas temperatures recorded in the upper chamber and difficulty maintaining slurry combustion. Initially, a dirty atomizer was suspected, but upon closer inspection, distortion of the combustor head liner was detected. The combustor head was removed, and it was found that several of the head liner attachment bolts had overheated, resulting in loss of support for the liner sections. One of the liner pie-shaped sections pulled away from the cover, resulting in distortion of the combustor flow field and direct slurry impingement on this section.

An alternate head liner configuration was designed and installed. The alternate design (see Figure 4.20) eliminates the need for attachment bolts, relying on an anchoring collar penetrating up through the head cover to support the center of the liner. The outer edge of the liner rests on the combustor upper chamber wall liner rather than being suspended from the head cover. The refractory material previously installed between the liner and the water-cooled head was also removed.

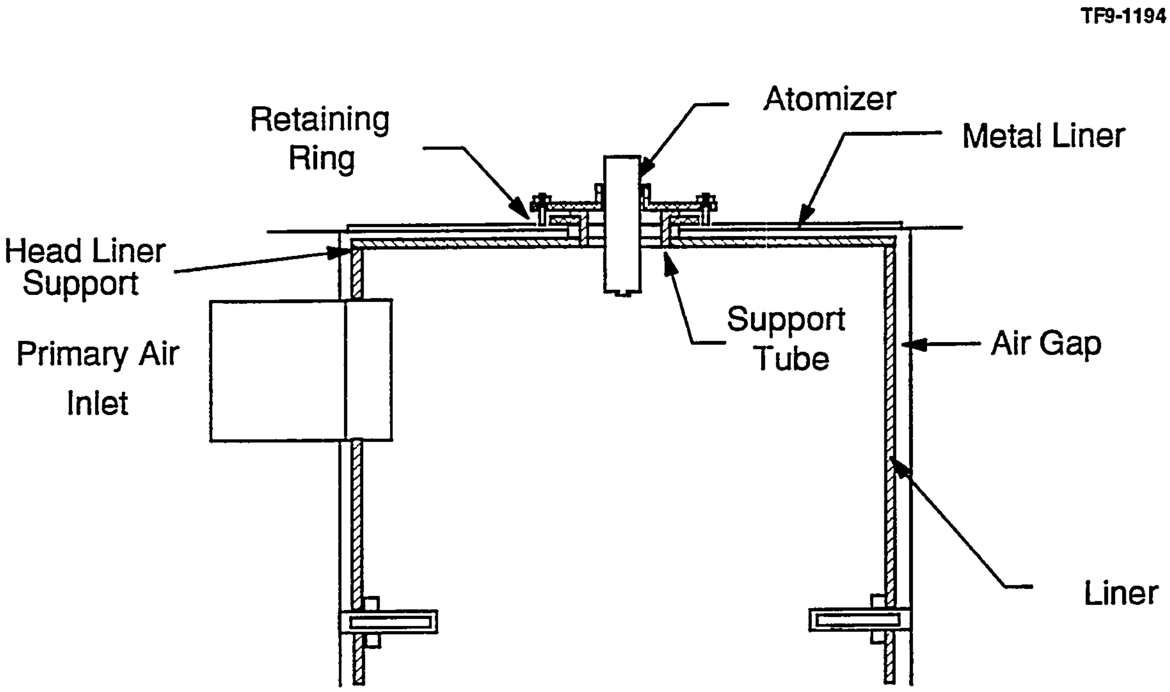

Figure 4.20 Head Liner Configuration

Additionally, it was found that the combustor upper chamber wall liner had a significant amount of wall loss just above the partition due to thermal and chemical effects. It was, therefore, decided to replace this liner at the same time. Thermocouples were installed directly onto the liner to closely monitor the liner temperatures at locations where excessive temperatures were evident. Also, the maximum combustor temperature setpoint will be lowered to initiate automatic system shutdown at lower upper chamber gas temperatures.

Analysis of the run data prior to the liner failure suggests that the initial cause of the higher upper chamber temperatures was a faulty secondary air flow differential pressure transmitter. A false reading was being detected, causing improper air flow to the combustor. This resulted in a change in the combustor vortex strength and a corresponding change in the flame location in the upper chamber. With the flame moved closer to the head, the temperature limits of the liner attachment bolts were exceeded. Modifications were made to the control software to limit the range of the primary and secondary air flows to further prevent a repeat of these events. The faulty pressure transmitter was replaced.

- Baghouse

Condensate traps were installed on the pressure sensing legs leading to the automatic pulse jet system. A handhole access was incorporated into the baghouse hopper to allow inspection of the rotary valve and hopper.

4.3 PERFORMANCE SUMMARY

Table 4.8 summarizes the overall system performance on each of the 3 coals evaluated during testing, and compares achieved performance to the program goals. Best performance results were obtained with the low ash Eastern Kentucky coal, but even with the higher ash, lower heating value Illinois coals, performance goals were met. With the Illinois coals, especially Illinois No. 6 with greater than 10% ash, system operation was more sensitive to slight changes in coal loading, slurry viscosity, and operating setpoints.

Figure 4.21 illustrates the turn down capability, ability to follow load, and operating flexibility of the system using Illinois No. 6 slurry. This figure plots the slurry flowrate and corresponding thermal input to the system over a 3 1/2 hour period. Figure 4.22 shows the corresponding combustor upper chamber gas temperature. Although this temperature, which is adjacent to the primary air inlet, varies slightly with changes in primary combustion air flow, resulting from load changes and changes in stoichiometry, it illustrates the stability of the combustion process over the full load range.

TABLE 4.8

PERFORMANCE GOALS

	Goal	Kentucky	Illinois No. 5	Illinois No. 6
Ignition	Safe and Reliable	30 Successful Starts	100 Successful Starts	30 Successful Starts
Turndown	3:1	4:1	3:1	3:1
Thermal Efficiency (percent)	>80	85 Clean 75 Dirty	85 with Soot Blower	85 with Soot Blower
Combustion Efficiency (percent)	>99	Baghouse Ash Burnout >99	96 – 99	97 – 99
Emissions (lb/mil Btu)				
NO_x	<0.3	0.26	0.30	0.27
SO_x	<1.2	1.03 lb/MMBtu (Compliance)	0.68	0.80
Particulates	<0.03	Baghouse Control	Baghouse Control	Baghouse Control

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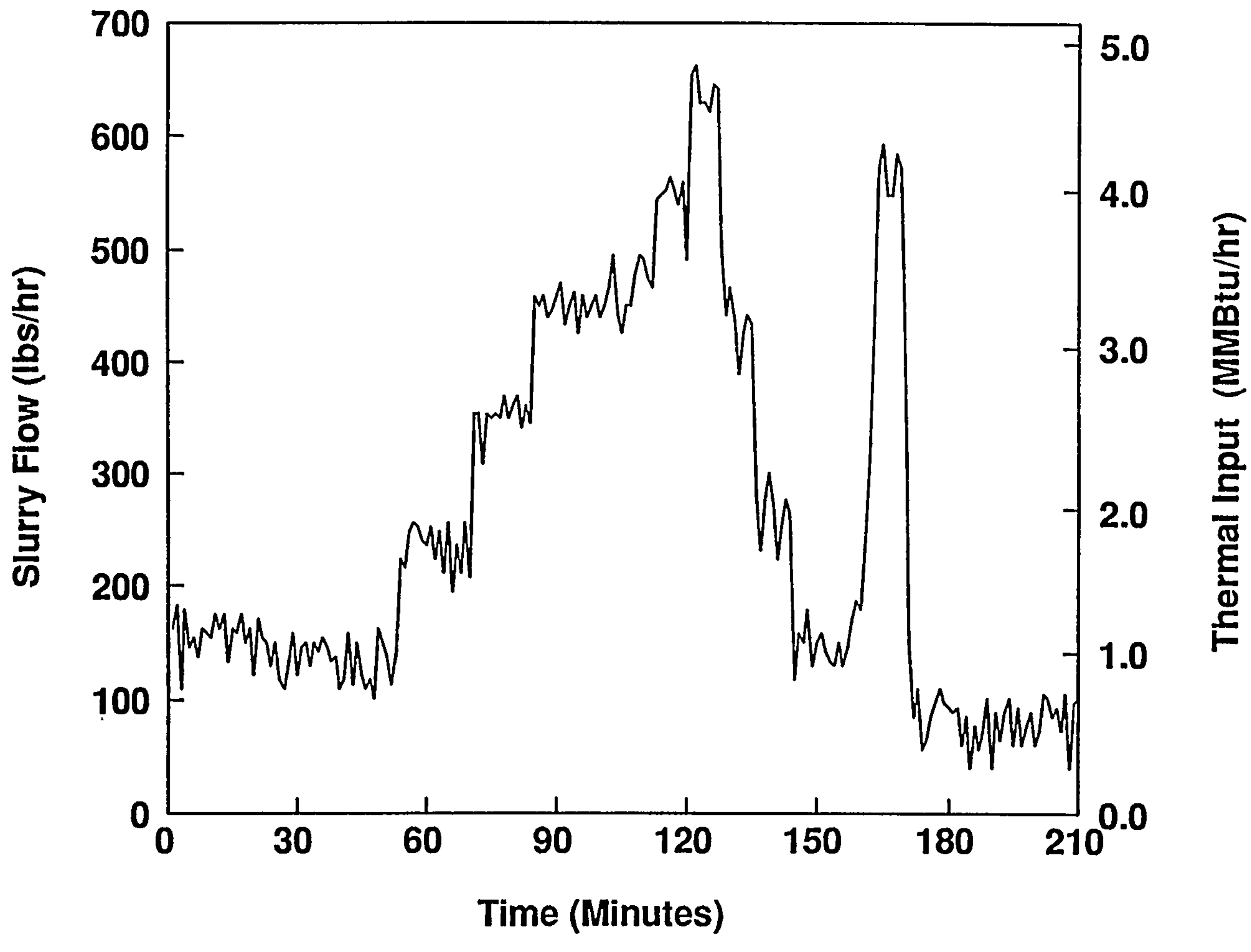

Figure 4.21 Thermal Input Versus Time With Illinois No. 6

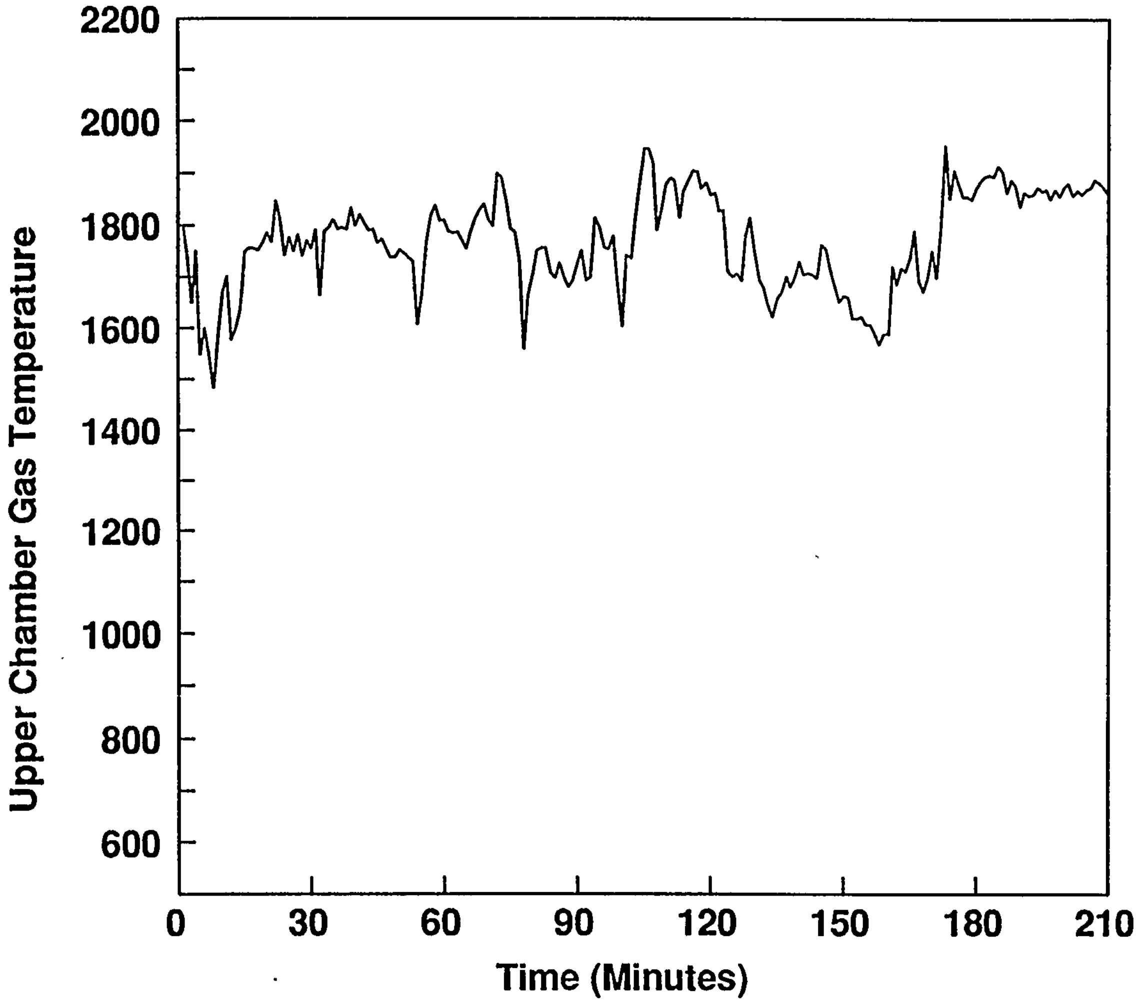

Figure 4.22 Combustor Upper Chamber Gas Temperature

In summary, the laboratory testing and host site operation has demonstrated the technical viability of the integrated system. The CWS combustor technology was scaled to the commercial market size, integration of the combustor technology with a conventional firetube boiler was demonstrated, and a highly efficient, low wear slurry nozzle was developed. Host site operation has demonstrated that the system can operate in an automatic, unmanned mode similar to premium fuel systems. Testing has demonstrated the ability to meet system performance goals utilizing 3 coals of varying quality, including high sulfur, high ash, Illinois No. 6 coal. Over the course of the development campaign, the system has operated for over 1300 hours, consuming over 30,000 gallons of slurry, demonstrating both the system's reliability and flexibility of operation. With all 3 coals, emission levels were below program goals and anticipated Clean Air Act levels. Operation requirements of system turndown, automatic startup, and trouble free operation were also demonstrated.

5. ECONOMIC EVALUATION

The commercial scale coal slurry-fired space heating system needs to be economically competitive, in addition to being technically sound and environmentally acceptable if it is going to successfully penetrate the market now dominated by oil and natural gas systems. The economic feasibility of the system is determined by capital investment and operating cost considerations. Due to the need for pollution control equipment, capital investment for a coal-fired system is greater than oil and natural gas systems, and therefore, total operating costs, including the cost for sorbent materials and ash disposal, must be lower for the coal-based system. A summary follows of the economic evaluation, including an assessment of the delivered slurry cost based on historical projections and the information gained in the design and operation of the slurry production facility for the program.

5.1 DIRECT INVESTMENT

The total direct investment required to install the heating system includes equipment, engineering, installation, and capital costs. These costs have been determined for the CWS-fired system and premium fuel (oil and natural gas) systems. The direct investment cost variation between oil and natural gas systems is small and therefore are treated as one, as far as direct investment is concerned. Although there is a slight increase in equipment and installed costs for steam systems as compared to hot water systems, this variation was deemed small and therefore a hot water system is used for the economic evaluation.

Figure 5.1 shows the equipment costs for premium fuel (fuel oil and natural gas) and CWS-fired systems. For the premium fuel system, the equipment costs are based on current York-Shipley pricing and includes all equipment with a typical "boiler island," including all necessary instruments and controls. The main connection points are: forced draft fan inlet, boiler outlet, burner fuel inlet, circulating water supply and return flanges, boiler connections for blowdown, drain, vent and boiler water make-up, and electrical enclosure terminal strips. The range in costs presented for the premium fuel systems is a result of the small difference in price for fuel oil, natural gas, and dual fuel equipment. More significantly, the reduction in price per unit thermal output is associated with less conservative boiler sizing at the expense of thermal efficiency.

For the CWS-fired system, the high volume manufacturing cost for CWS-fired space heating systems was determined based on the equipment costs for the development unit and the experience of Tecogen and York-Shipley in performing similar scale-up and commercialization. Table 5.1 summarizes the development unit equipment costs and the predicted high volume costs for a 3.2 MMBtu/hr thermal output unit. The range in costs presented for the CWS-fired system is mainly a result of the uncertainty in high volume production cost pricing and variation in scope of supply, especially regarding instrumentation and controls to achieve fully automatic operation. As seen in Figure 5.1, the equipment costs for the CWS system is on average two to three times that of the premium fuel system, depending on the size of the unit. This difference is mainly a result of the added

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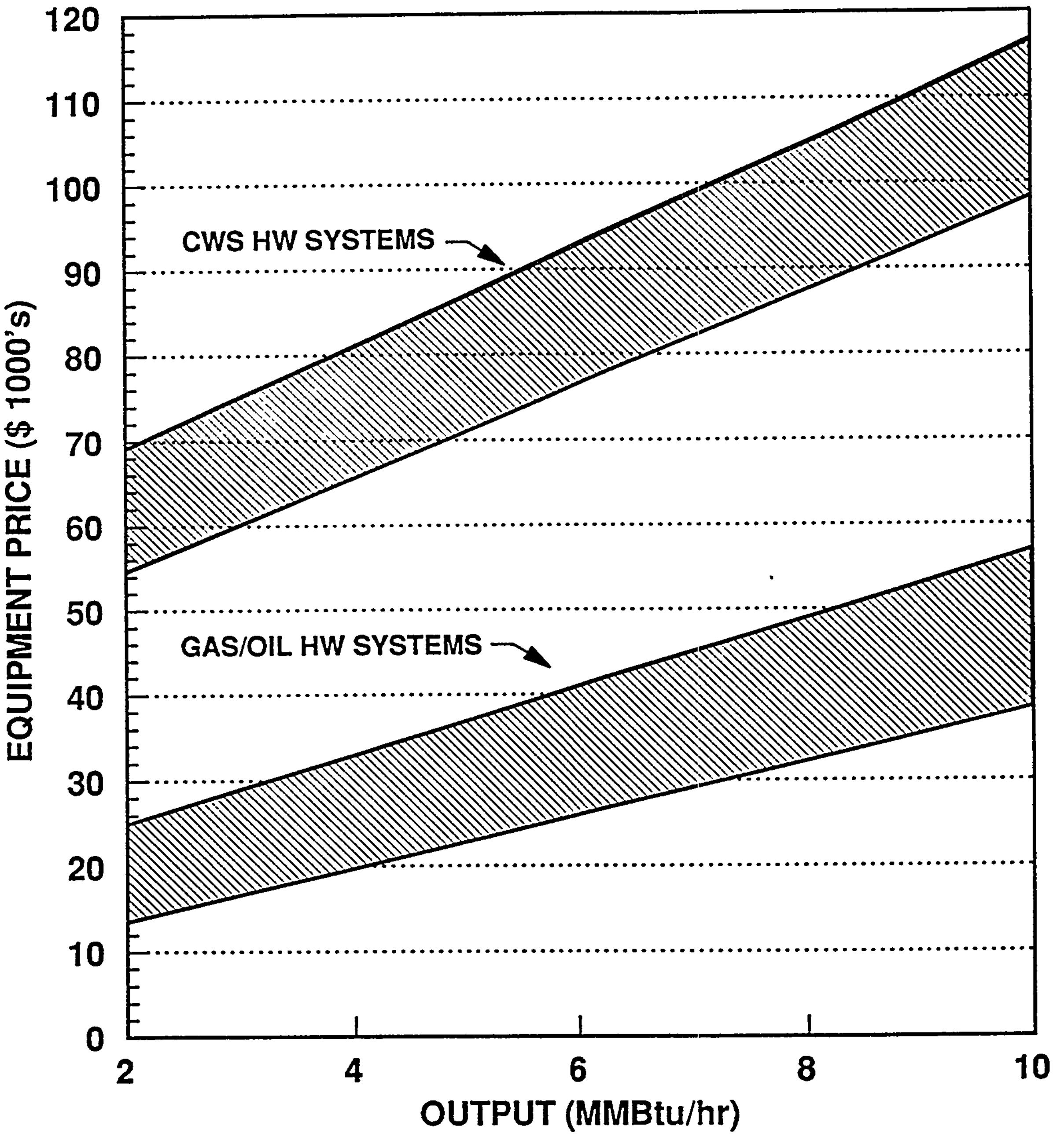

Figure 5.1 CWS and Premium Fuel Hot Water Boiler Equipment Costs

TABLE 5.1

EQUIPMENT COST ESTIMATE FOR 3.2 MMBTU/HR THERMAL OUTPUT CWS SYSTEM

SYSTEM COMPONENTS	DEVELOPMENT UNIT COST ($)	HIGH VOLUME SYSTEM COST ($)
COMBUSTOR/BOILER		
Combustor/Transition Chamber	20,790	3,500
Expansion Joint	1,075	1,075
Boiler	19,230	19,230
Combustor Cooling Water Pump	679	679
Soot Blower	4,330	3,000
Exhaust Piping	1,909	NA
Combustor Cooling Water Piping	2,000	800
Structure	1,000	600
Subtotal	51,013	28,684
COMBUSTION AIR SYSTEM		
FD Fan	2,060	1,500
Air Control Valves	1,896	1,200
Air Piping	500	NA
Subtotal	4,456	2,700
EMISSIONS CONTROL SYSTEM		
ID Fan	1,165	800
Exhaust Damper	1,650	NA
Baghouse	7,879	6,000
Sorbent Feeder	3,860	3,000
SO_2 Reactor	3,300	2,000
Sorbent Storage Hopper	2,000	2,000
Ash Collection System	NA	3,000
Subtotal	20,819	16,800
FUEL SYSTEM		
Fuel Oil Pump	321	321
Fuel Oil Flow Meter	720	NA
Fuel Oil Control Valve	969	969
Slurry Pump & Controller	1,456	1,000
Slurry Flow Meter	5,590	NA
Threeway Valves	1,569	520
Atomizer	1,600	2,500
Pilot System & Flame Safety	572	572
Subtotal	12,797	5,882
CONTROLS		
Controller	11,000	2,500
Relays, Breakers & Starters	2,170	2,170
Enclosures	2,037	1,000
Pressure Transmitters	2,595	500
Cooling Water Flow Meter	1,670	NA
Circulation Water Flow Meter	1,670	NA
Combustor Water Flow Meters	990	NA
Subtotal	22,132	6,170
TOTAL	106,887	60,236

NA = Not Applicable

pollution control equipment required of the coal-based system. The costs can be reduced, if low sulfur CWS fuel is utilized, by eliminating the need for the equipment associated with post combustion sulfur removal. It is likely, even with the most aggressive coal cleaning techniques, that particulate control equipment will be necessary because, even with zero ash in the CWS fuel at 99% combustion efficiency, particulate emissions would exceed standards.

Figure 5.2 gives the corresponding installation costs for the systems. The installation costs include placement of the equipment at the site, all plumbing and stack connections, and all electrical hook-ups. It does not include the piping and equipment associated with the building's heating system; 50 feet of circulating water piping in the boiler room is included for interface with the system. Also not included is the cost of the fuel storage tanks for either the oil or CWS systems.

Finally, Figure 5.3 gives the total investment costs for the premium fuel and CWS-fired systems. The total investment cost or capital cost is the sum of the equipment and installation costs, along with costs associated with site engineering and design, permit procurement, and system start-up. In summary, the total capital investment for a CWS-fired space heating system is estimated to be approximately 2 to 2 1/2 times higher than a premium fuel system.

5.2 OPERATING COSTS

Since the total investment required for a CWS-fired space heating system is significantly higher than a premium fuel system, operating costs must be less to justify the greater initial investment. Operating costs consist of fixed and variable types. Fixed costs are independent of capacity factor, while variable costs are mostly made up of consumables and maintenance charges. Operating costs include operating and maintenance labor, spare parts, and consumables. Consumable costs can include fuel, water, electricity, chemicals, and waste disposal.

Operating costs for both premium fuel and CWS-fired systems were determined for a wide range of operating conditions and baseline assumptions. Since the difference in energy costs between the premium fuels and CWS is the economic driver making the use of CWS attractive, the economic comparison is made on the basis of the differential fuel cost. This also simplifies the comparison because it enables the results to be compared independently of fuel price projections. Price projections can be made independently and the resultant differential fuel cost utilized to evaluate the economic benefit of the CWS-based system. In Section 5.3, the projected fuel cost differential between CWS fuels and oil and natural gas is discussed.

Two economic indicators are utilized to assess the attractiveness of the CWS-based heating system: simple payback and total life cycle savings. In evaluating alternate technologies which require additional up-front capital expenditures such as the CWS-fired space heating system, commercial and industrial users typically are most interested in how soon the equipment will pay for itself, or simple payback, and the accepted time period for payback is influenced by the total savings potential of the alternative system for the life of the equipment, or total life cycle savings.

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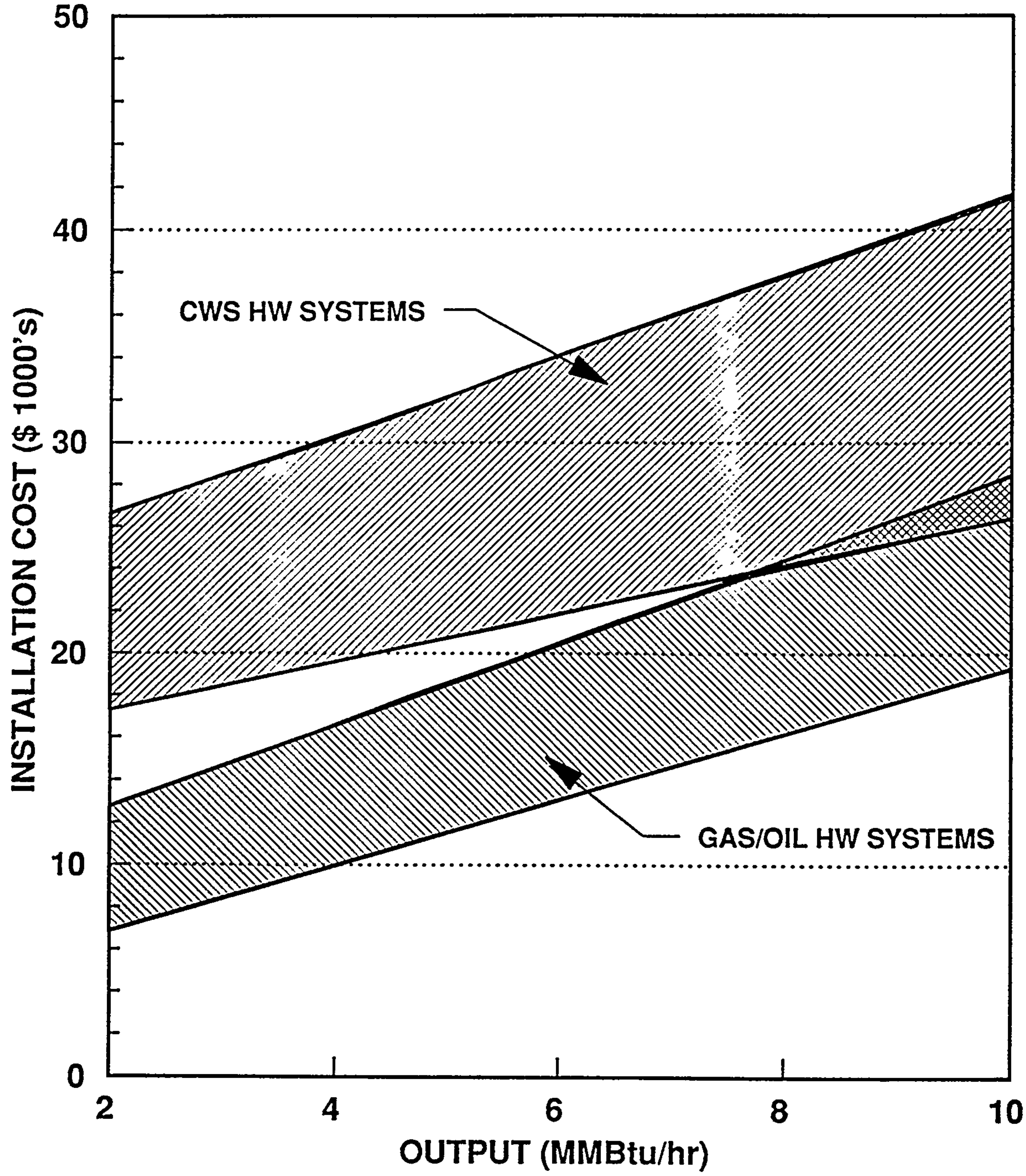

Figure 5.2 CWS and Premium Fuel Hot Water Boiler System Installation Costs

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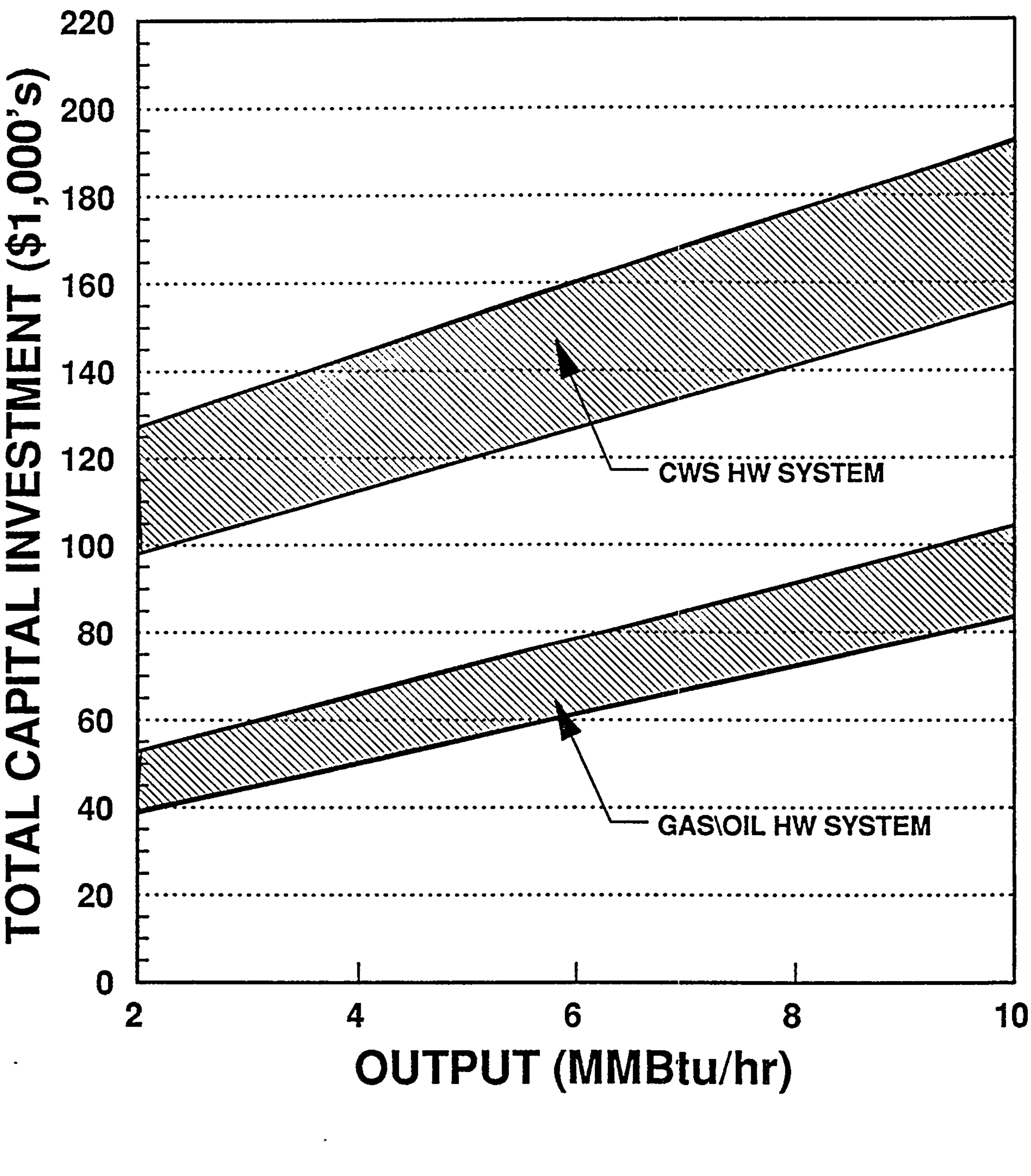

Figure 5.3 CWS and Premium Fuel Hot Water Boiler Total Capital Investment

Figures 5.4 through 5.6 show the results for the simple payback analysis for each of the program coals. Table 5.2 summarizes the assumptions made in determining the system payback. It is evident from these results that CWS quality, i.e., sulfur and ash content, strongly influences the payback period. This is more clearly illustrated in Figure 5.7, where the payback period vs. fuel cost differential is plotted for 5 coals of varying sulfur and ash content for a 6 MMBtu/hr system. Three of the coals are the coals utilized in the test program, Eastern Kentucky Hazard, Illinois No. 5, and Illinois No. 6, and the 2 additional coals, a low ash (3.7%), high sulfur (3.14%) coal, and a high ash (11.8%), low sulfur (0.76%) coal, are utilized to demonstrate the sensitivity of the payback period to coal quality. It is evident from the plot that sulfur content of the coal strongly influences the payback period through increased sorbent cost and correspondingly higher disposal costs.

This is further illustrated in Figures 5.8 through 5.10, which give the breakdown in annual operating costs for the various size systems and coals. For the high sulfur Illinois No. 6 coal, the combined cost for sorbent and disposal of the spent sorbent/ash mixture exceeds the cost of the slurry, drastically increasing the payback period. The annual fuel costs are calculated for a baseline slurry price of $2/MMBtu, and therefore, depending on transportation charges associated with fuel delivery, the CWS fuel costs will be correspondingly a greater percentage of the total annual costs.

The payback period and annual operating costs shown in Figures 5.4 through 5.10 were based on an overall annual system utilization of only 20%. This 20% utilization was based on a 5 month heating season and an average load factor of 50%. Payback periods can be drastically reduced if the CWS system is operated as a baseload system, which would increase the average load factor to closer to 100%, or if the system is utilized year round for non-space heating applications, such as domestic hot water or process heating. Figure 5.11 gives the required payback period for a system utilizing Illinois No. 5 CWS operating for the 5 month heating season as a baseload unit (3600 hours, load factor = 1.0). Since maintenance costs are fixed, the payback period is less than half the baseline case of Figure 5.5.

Total life cycle savings for the corresponding cases of Figures 5.4 through 5.6 are given in Figures 5.12 through 5.14. Since the life cycle savings are incurred over the entire 20 year operating life of the equipment, the following escalation factors were utilized: a general interest rate of 5% was used for the cost of money, a price increase of 3% a year for sorbent, a price increase of 10% a year for ash disposal, and an escalation rate of 8% per year for maintenance. An annual price escalation of 5% was used for the premium fuels and a 1% escalation was used for the CWS fuels (see Figure 5.15).

These figures show that, for the low and moderate sulfur fuels, present value life cycle savings of millions of dollars are predicted at moderate CWS to premium fuel price differentials. For the higher sulfur Illinois No. 6, slightly higher differentials are required to achieve this level of savings, but, especially for the larger size units (8 to 10 MMBtu/hr), significant saving can be obtained at fuel cost differentials of $4/MMBtu.

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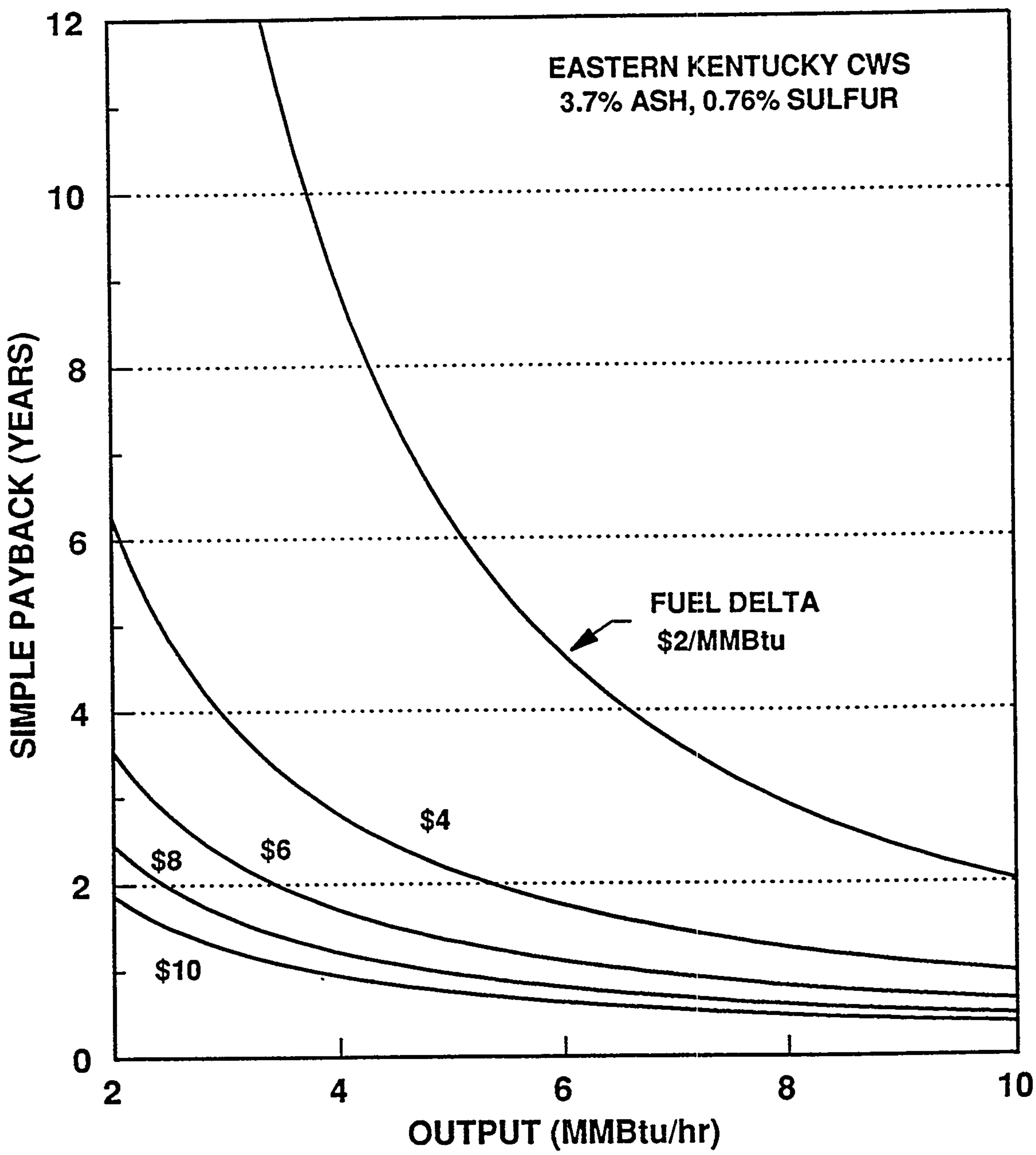

Figure 5.4 CWS-Fired System Capital Payback Utilizing Eastern Kentucky CWS

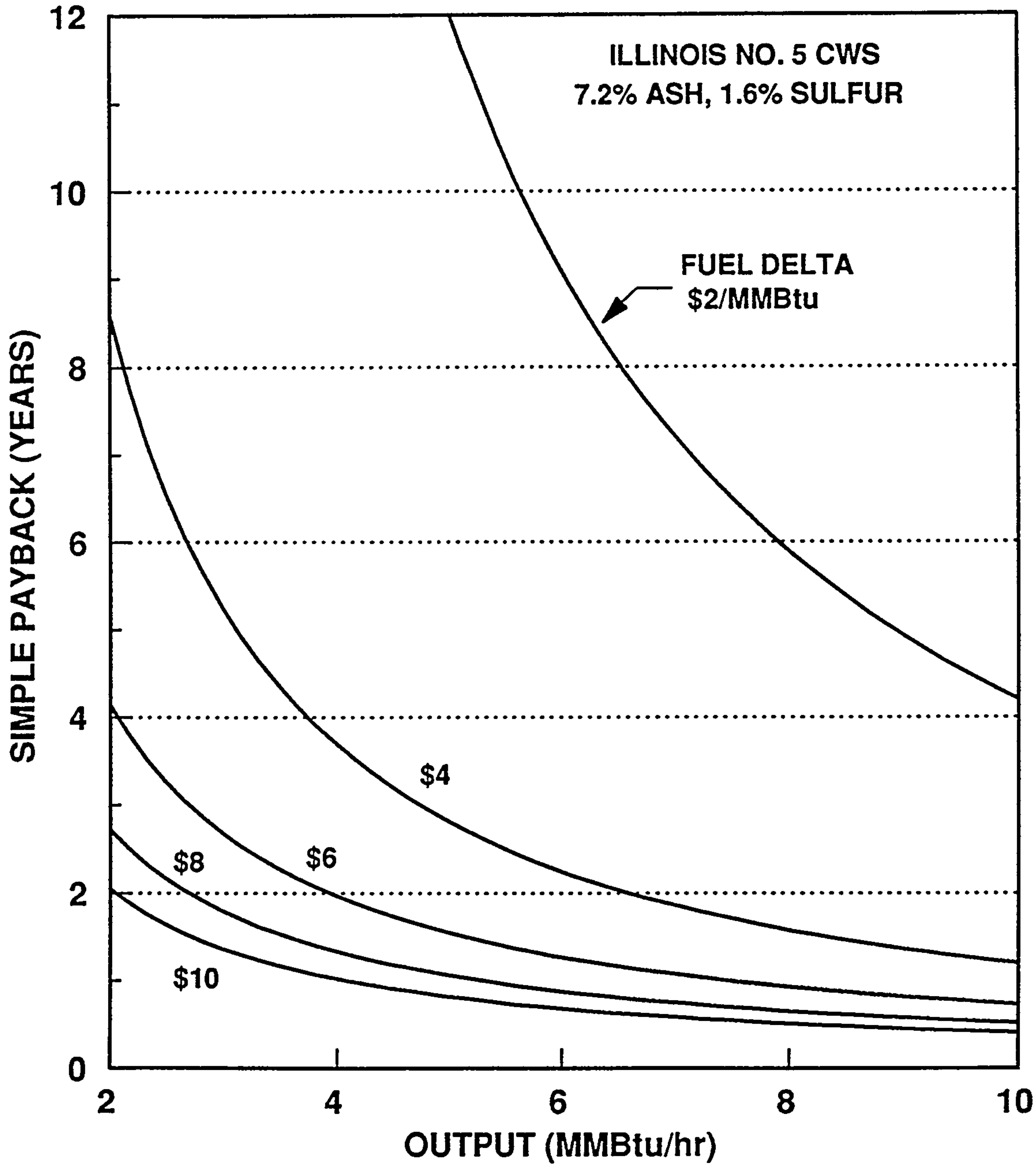

Figure 5.5 CWS-Fired System Capital Payback Utilizing Illinois No. 5 CWS

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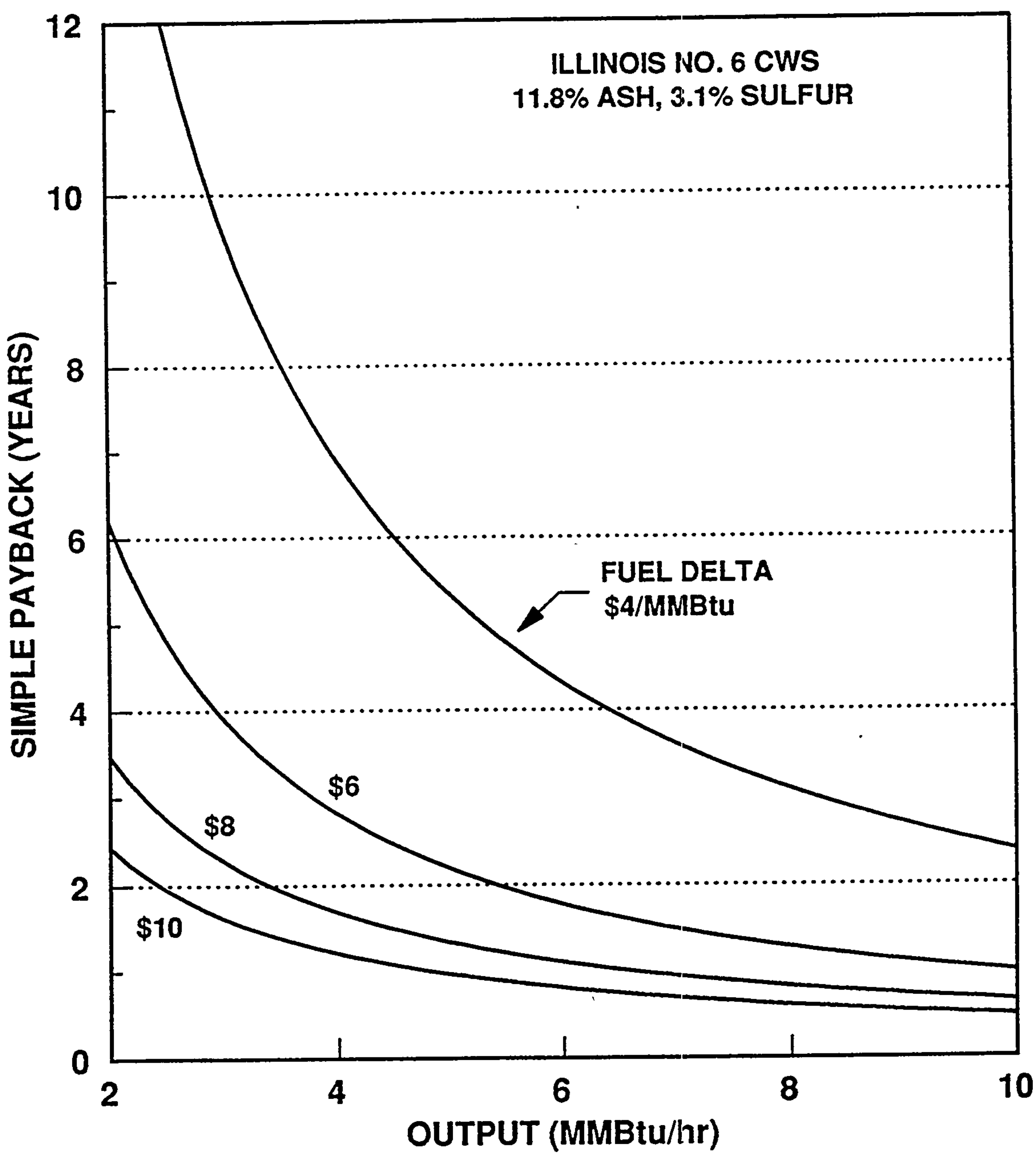

Figure 5.6 CWS-Fired System Capital Payback Utilizing Illinois No. 6 CWS

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TABLE 5.2

SYSTEM PAYBACK ANALYSIS ASSUMPTIONS

Operating Hours	3600
Load Factor	50%
Sorbent Cost	$270/ton
Disposal Cost	$64/ton
Sorbent Utilization	80%
Baseline CWS Cost	$2/MMBtu
Maintenance Labor Oil/Gas CWS Spare Parts	 1 hr/wk 7 hr/wk 5% of Equipment Cost Annually

Figure 5.6 CWS-Fired System Capital Payback Utilizing Illinois No. 6 CWS

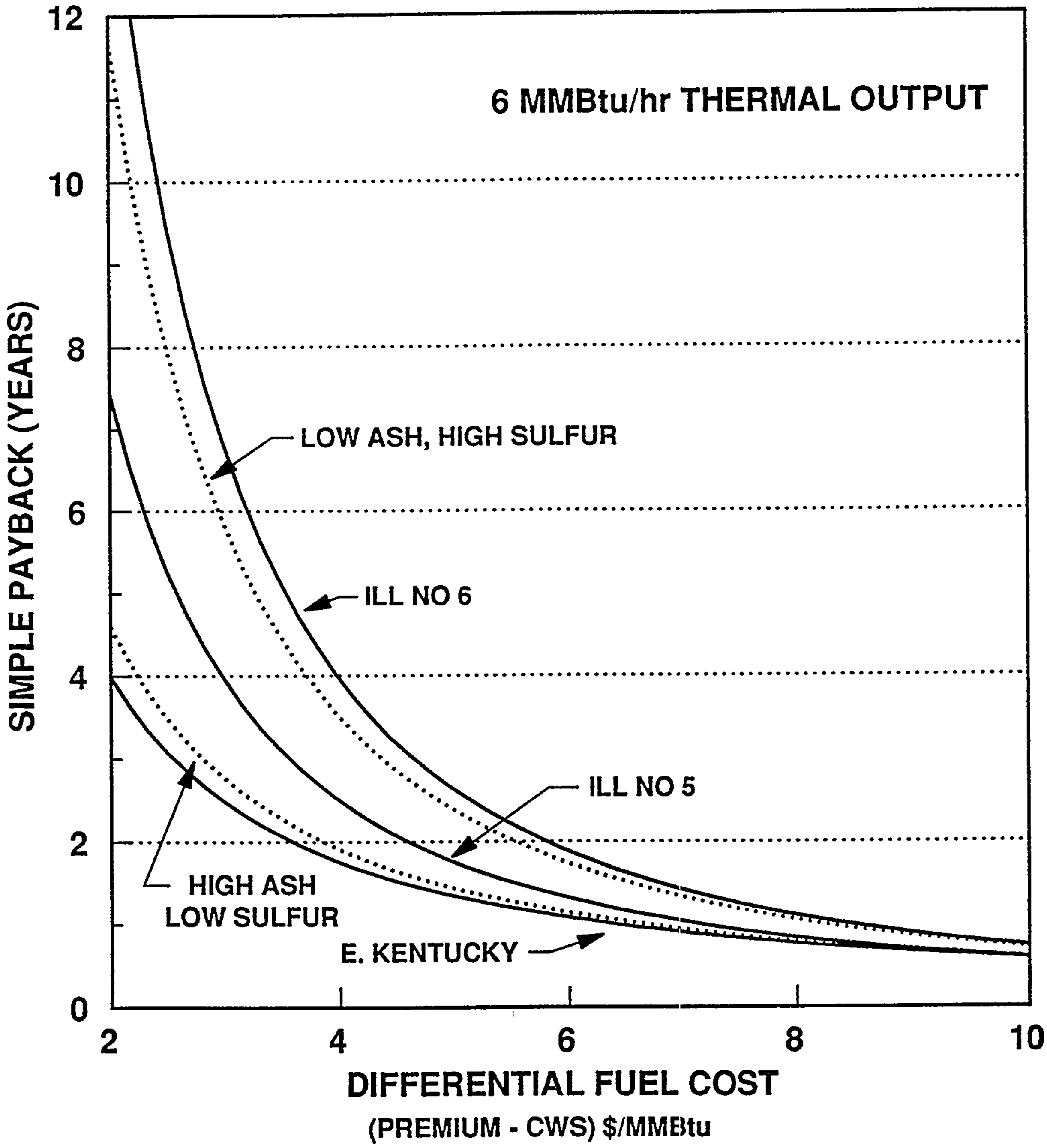

Figure 5.7 Coal Quality Effect on Payback Period

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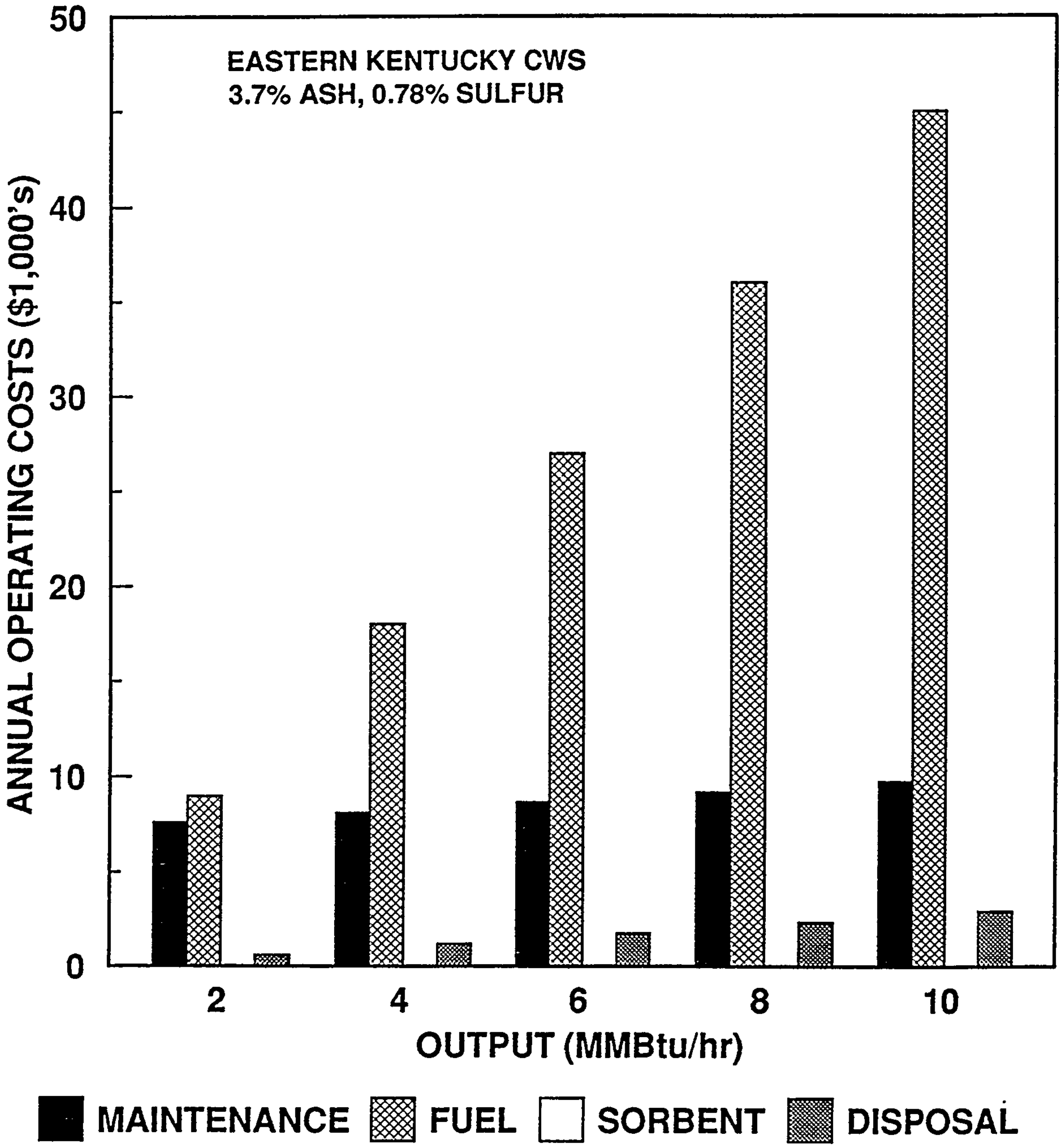

Figure 5.8 Annual Operating Cost Utilizing Eastern Kentucky CWS

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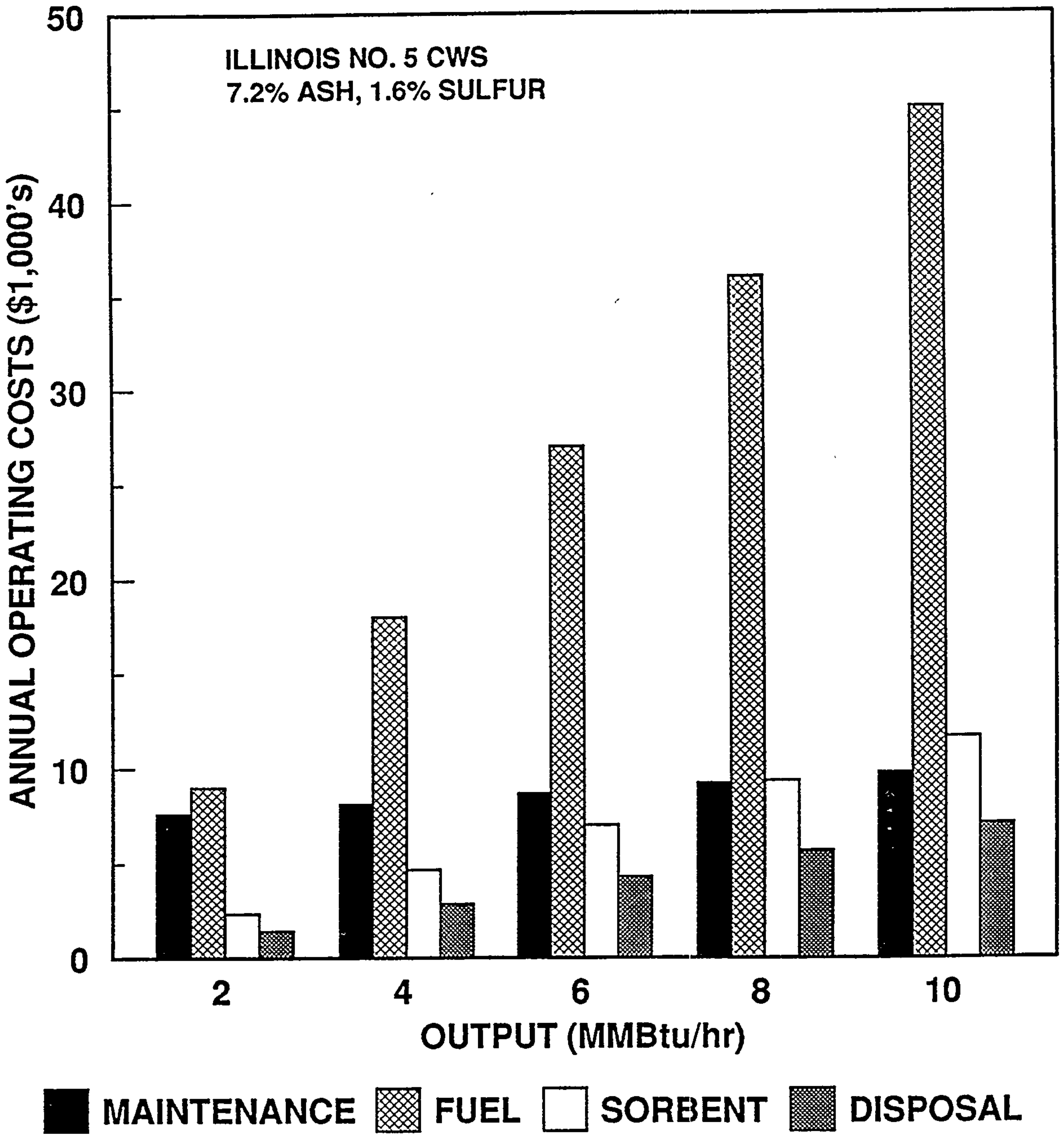

Figure 5.9 Annual Operating Cost Utilizing Illinois No. 5

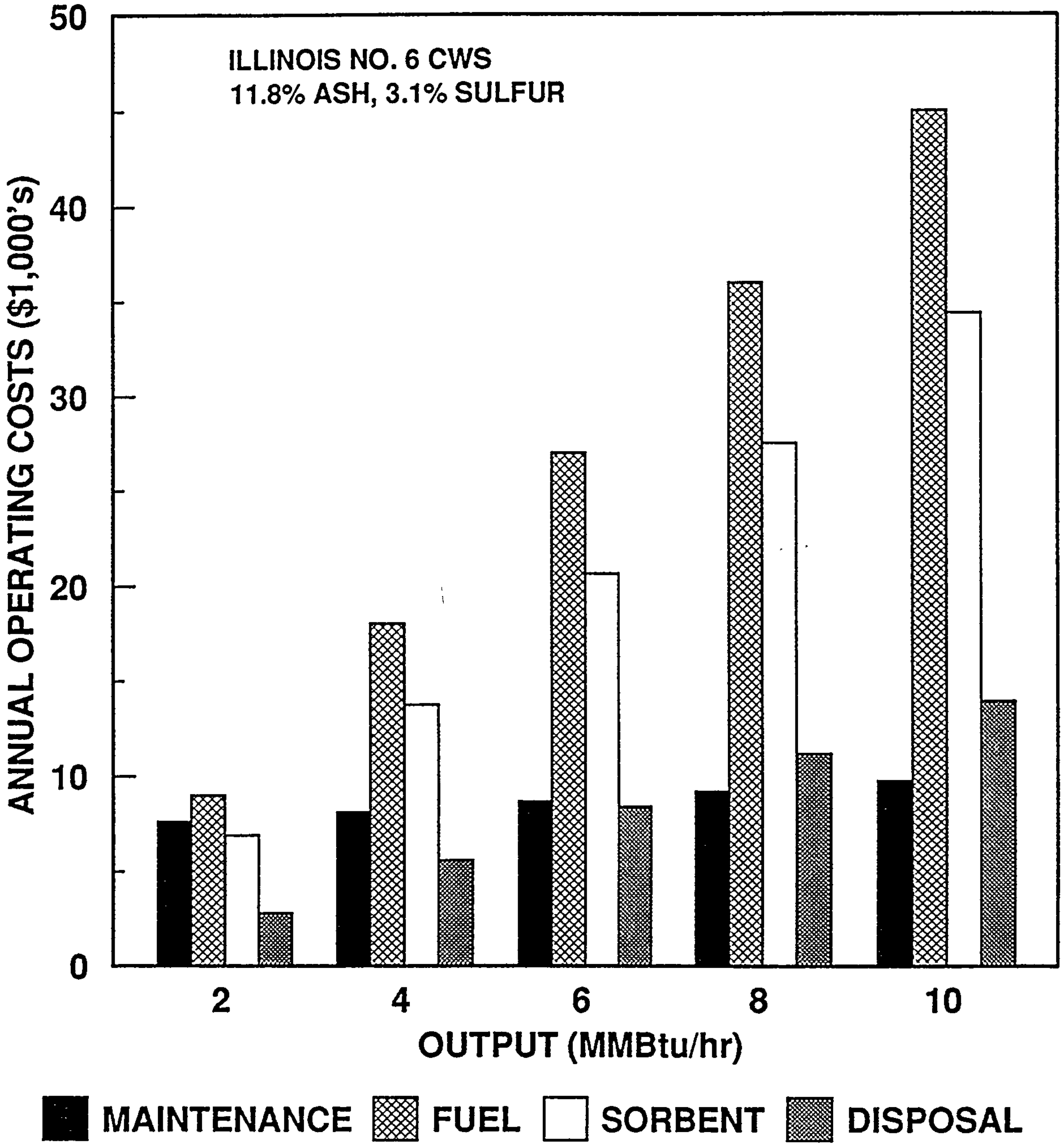

Figure 5.10 Annual Operating Cost Utilizing Illinois No. 6

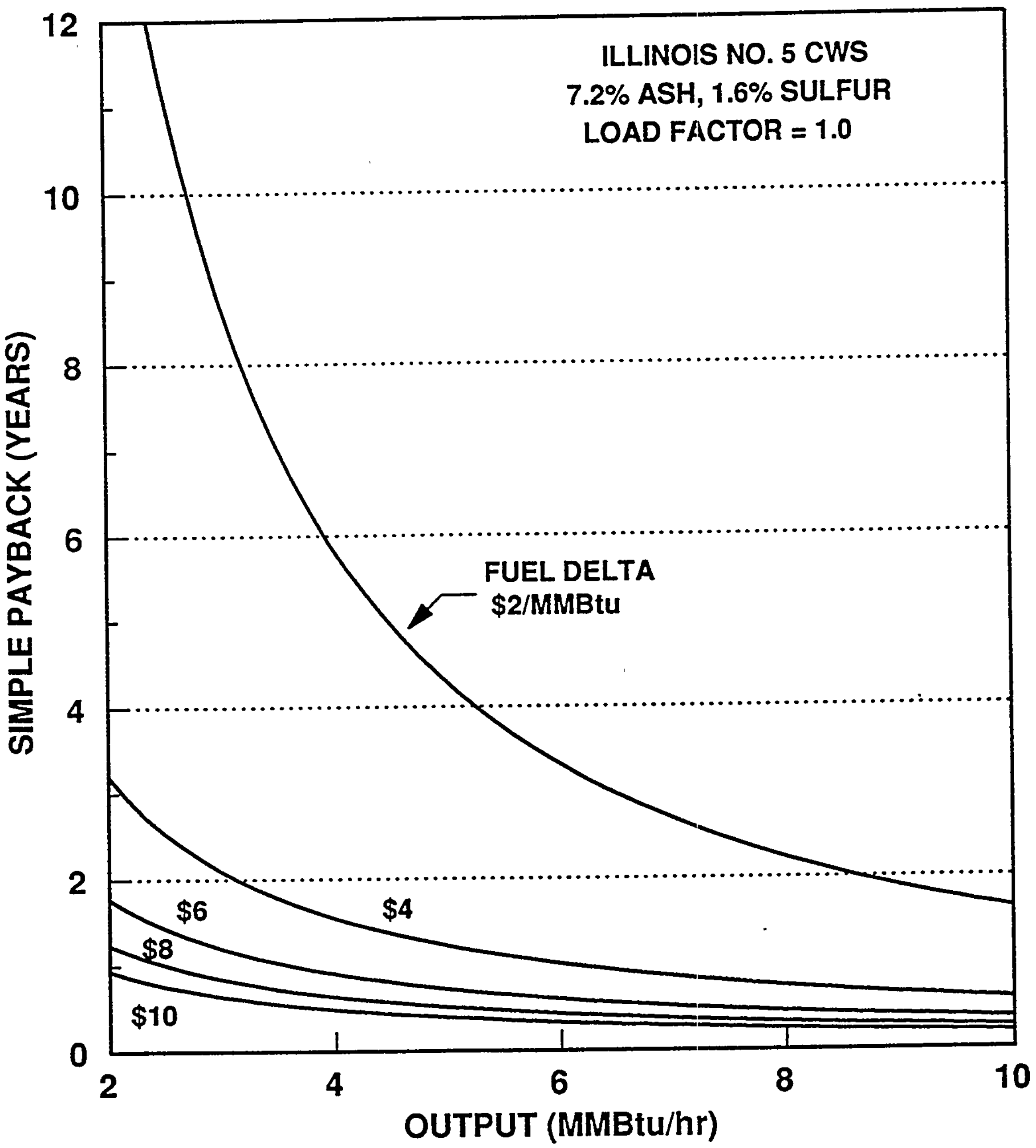

Figure 5.11 Capital Payback Period for System Load Factor of 1.0
Illinois No. 5 CWS

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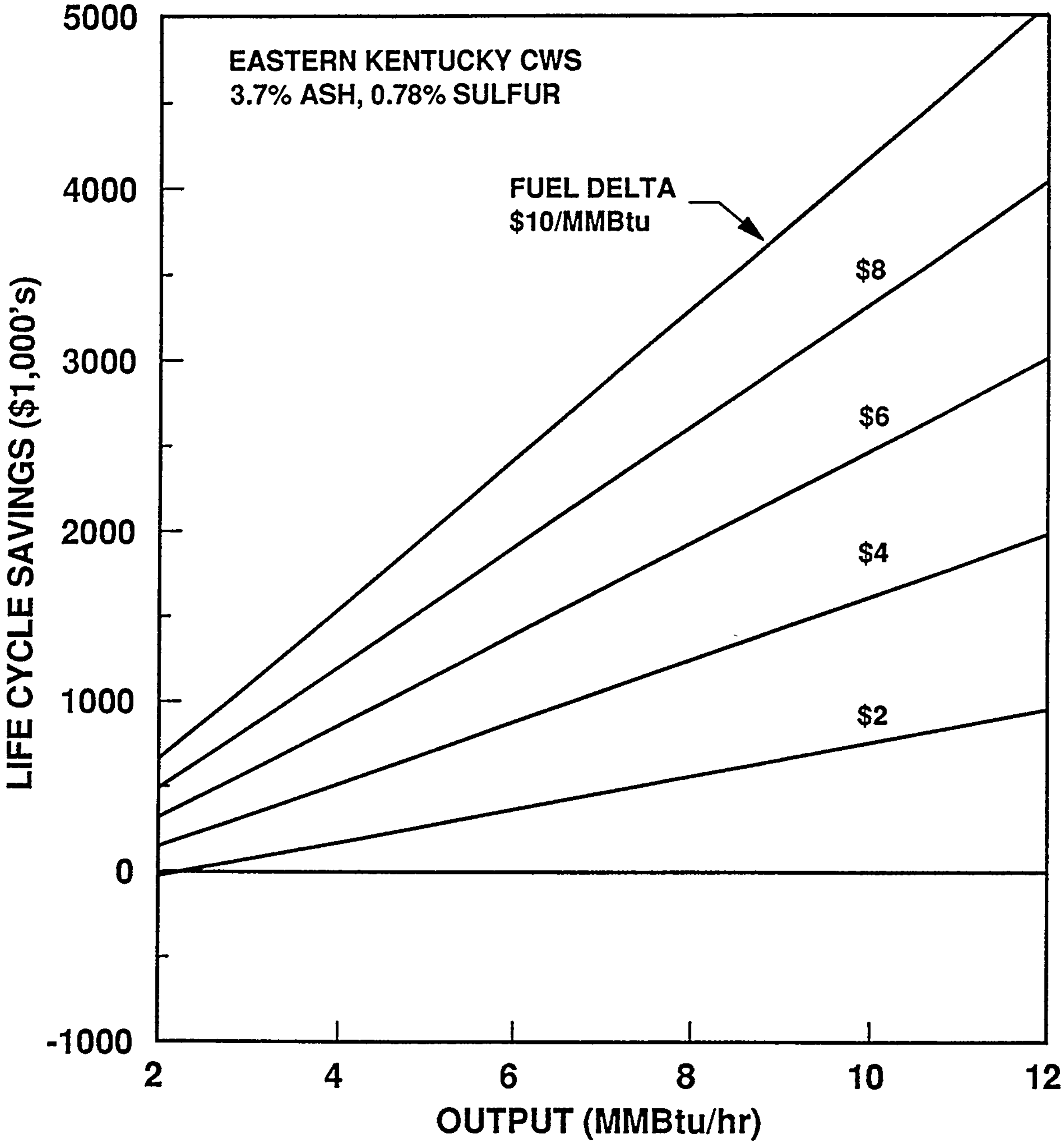

Figure 5.12 Life Cycle (20 Year) Savings Utilizing Eastern Kentucky CWS

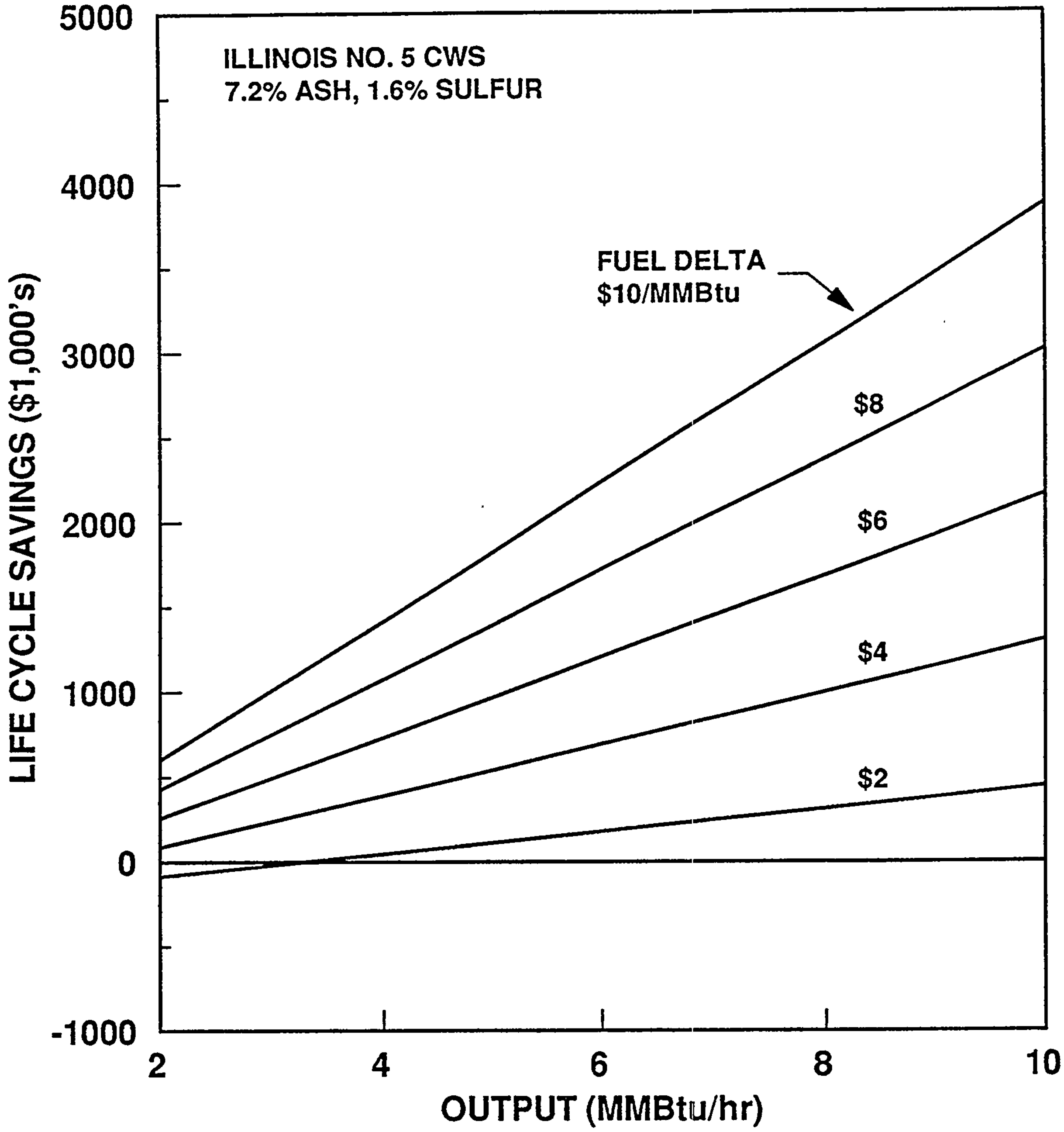

Figure 5.13 Life Cycle (20 Year) Savings Utilizing Illinois No. 5

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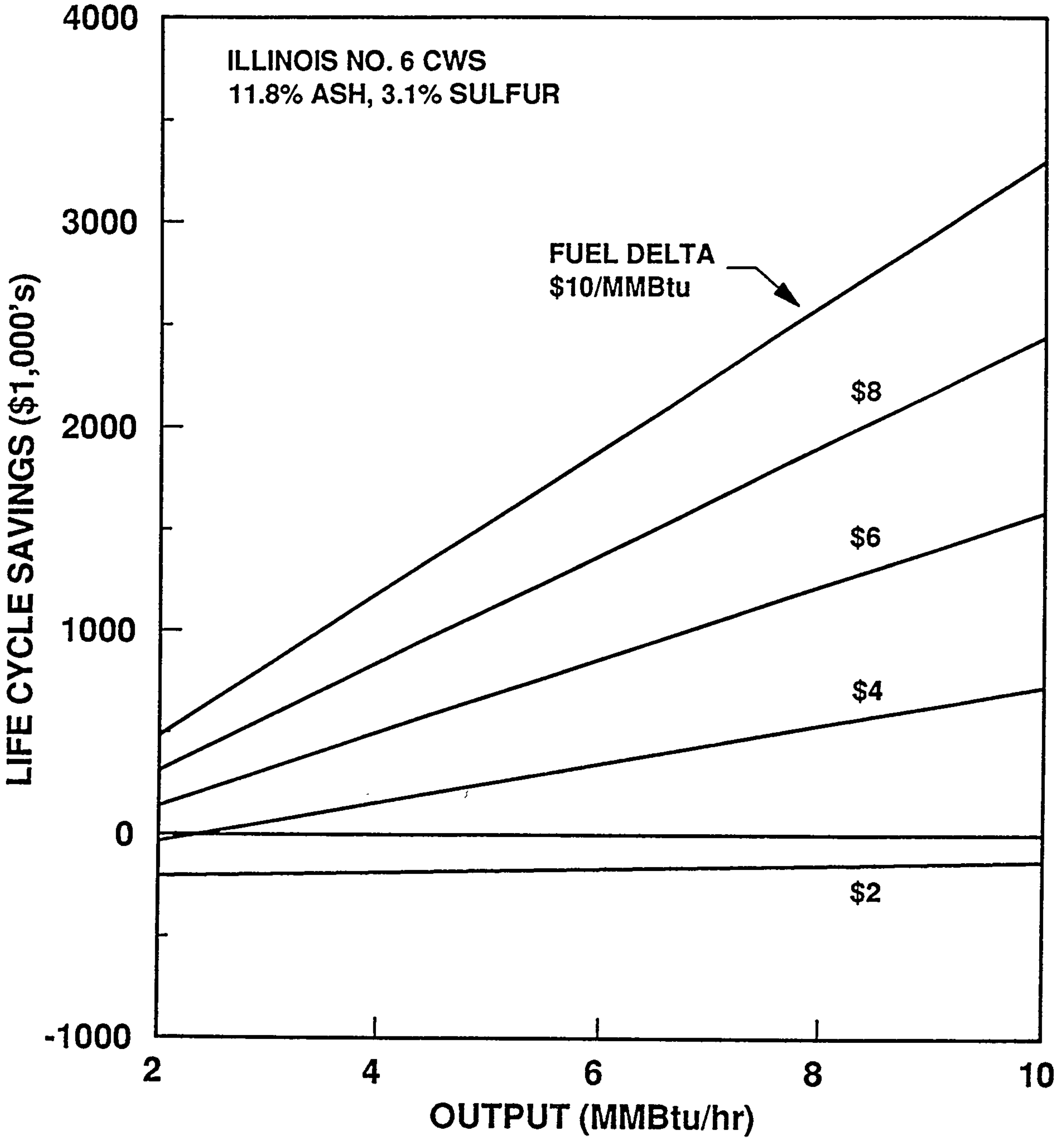
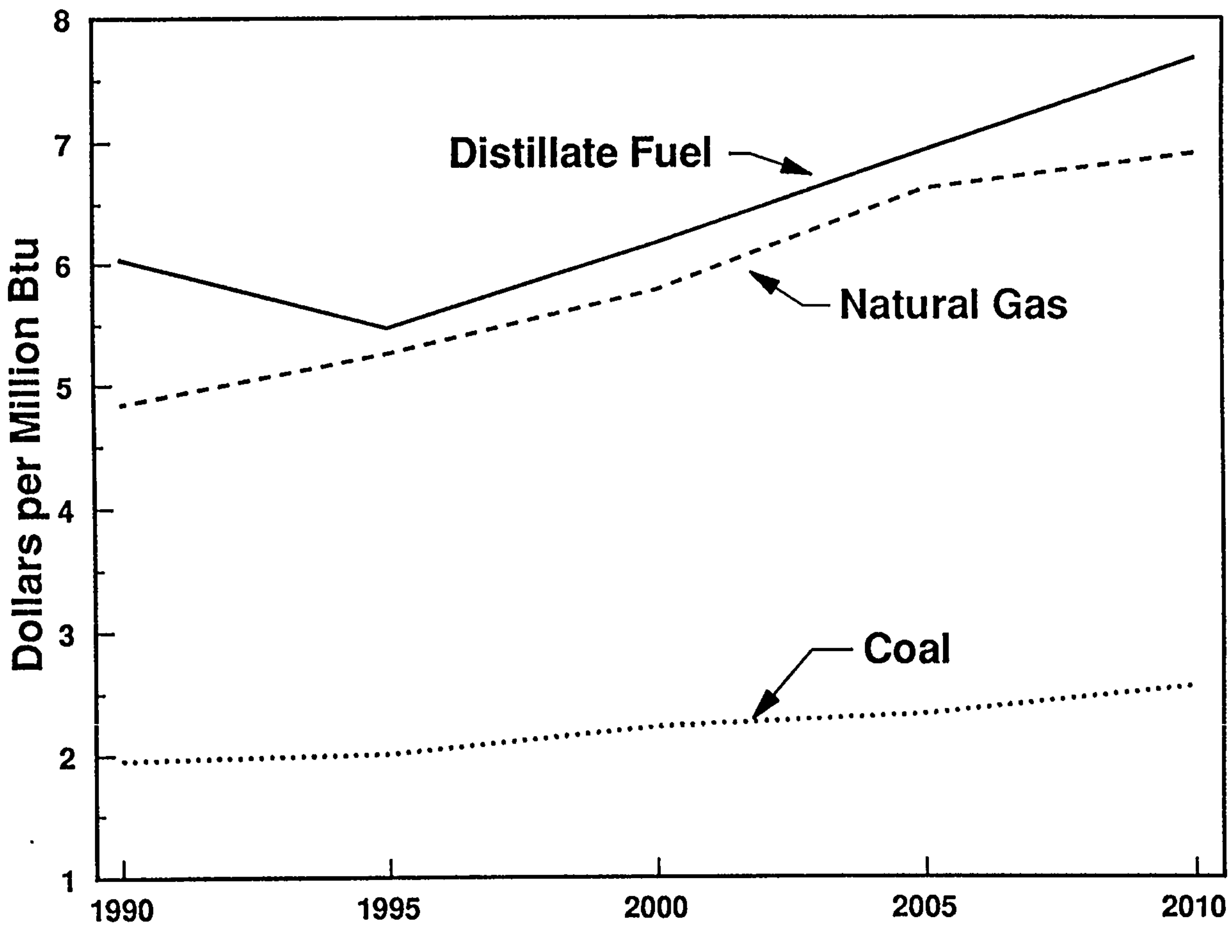


Figure 5.14 Life Cycle (20 Year) Savings Utilizing Illinois No. 6



Annual Energy Outlook 1993, January 1993, Table A3, Commercial Sector (1991 Dollars)

Figure 5.15 Fossil Fuel Price Projections

5.3 CWS FUEL COST

As demonstrated in the above economic evaluation, the price differential between premium fuels and CWS strongly influences the economic viability of a coal-based heating system technology for the commercial scale market sector. This differential is a function of current and projected premium fuel prices and the cost of CWS production and transportation. Since the production of CWS is not currently being carried out commercially, and a distribution infrastructure for the fuel is non-existent, introduction of CWS-based combustion systems will require the co-development and commercialization of a CWS-based production and distribution network. At today's coal price of $30 per ton, or $1.2/MMBtu, and premium fuel prices of $4.0 and $5.3/MMBtu for natural gas and home heating oil, respectively, there is a significant margin to enable CWS to be cost effective in selective market areas. With the differential between coal and premium fuel prices predicted to increase, as shown in Figure 5.15, the CWS market will most certainly grow.

A recent study by Science Applications International Corporation projects a plant gate cost of $1.85/MMBtu for CWS. This projection is for slurry produced at the coal mine and includes a small degree of beneficiation. Non-beneficiated slurry costs may be as low as $1.65/MMBtu. Similar cost projections have been made by the Japan COM Company, Ltd, a joint venture company established to provide CWS produced in China to Japanese users. This is the first project to sell CWS in the international energy market as an alternative to premium fuels. They predict a slurry cost of $1.82/MMBtu for slurry made in China and shipped to Japan and $2.11/MMBtu for slurry made in Australia and shipped to Japan. Figure 5.16 gives the cost breakdowns for these two cases at a production rate of 1,000,000 tons per year.

With plant gate cost of CWS established, the cost of distributing the fuel to commercial users must be predicted. Since a distribution system is not currently available, distribution cost projections can vary widely. Assuming no dedicated distribution network with transport by common bulk carrier, CWS costs quickly become uncompetitively high moving further from the mine mouth slurry production facility or major relay station. Figure 5.17 shows the projected delivered costs for this scenario. On the other hand, if one assumes a complete distribution infrastructure has been developed for CWS, allowing tank car or slurry pipeline transport to regional centers, the delivery costs for CWS can be on a par with current fuel oil delivery costs. Transportation and handling costs for home heating oil from refinery to commercial user is approximately $2.5/MMBtu. This is the difference in price between the cost of home heating oil at the refinery and that paid by the residential or commercial user. Table 5.3 gives a breakdown of these prices for various regions of the country and the national average. Assuming 50% of this cost is attributed to overhead and profit and accounting for the difference in heating value on a volume basis between fuel oil and CWS, a transportation and handling cost of $3.5/MMBtu can be expected, resulting in a delivered slurry cost of $5.35/MMBtu throughout the country.

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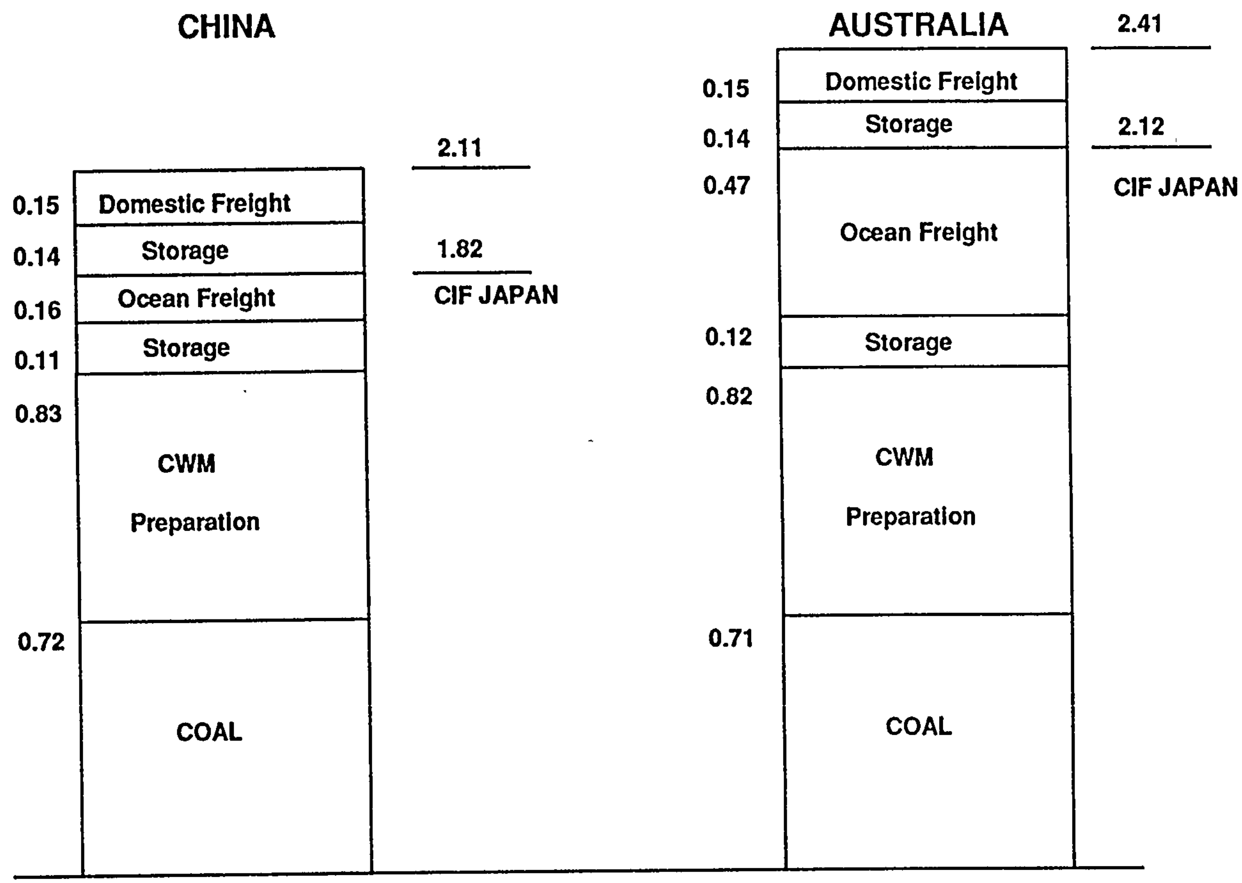

Source: "Annual 250,000 tons of CWM Production by a China-Japan Joint Venture Company at Shiuiu, Shantong, China," Noboru Hashimoto, et. al., Proceedings of the 17th International Conference on Coal Utilization

Figure 5.16 CWS Cost Breakdown (FOB Japan) – 1,000,000 Tons Per Year Production

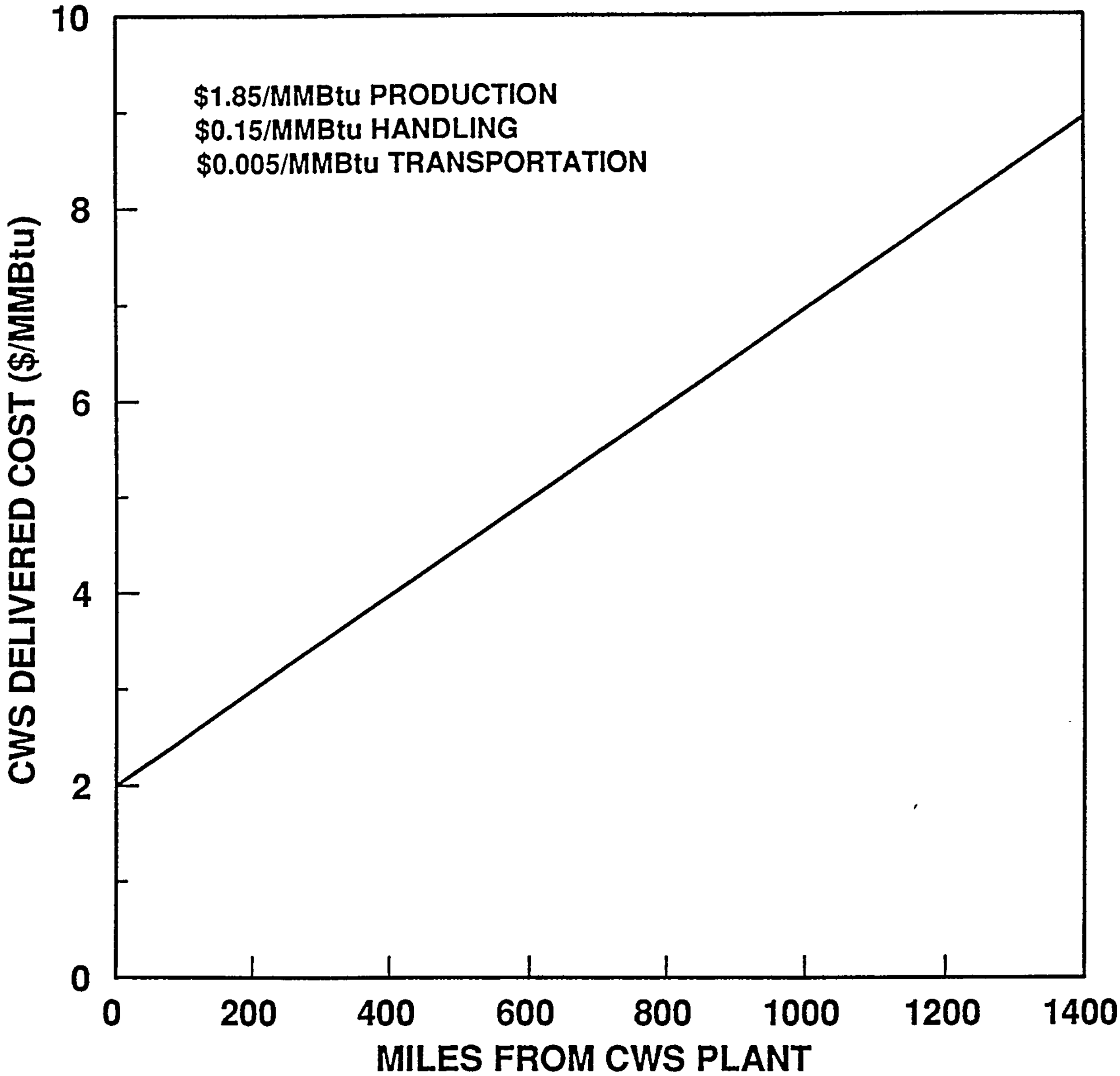

Figure 5.17 CWS Delivered Cost Versus Miles From Plant

TABLE 5.3

1991 AVERAGE NO. 2 FUEL OIL PRICES

	Price at Refinery ($/MMBtu)	Price Paid by Residential User ($/MMBtu)	Handling and Transportation Cost ($/MMBtu)
Massachusetts	4.7	7.2	2.5
Pennsylvania	4.5	7.0	2.5
Illinois	4.2	6.5	2.3
Idaho	4.4	6.7	2.3
California	4.7	7.0	2.3
National Average	4.4	7.2	2.8

Source: Energy Information Administration.

The above discussion and previous economic evaluation of the CWS-fired space heating system leads to the conclusion that, in the future, when a CWS distribution network is established, CWS-based heating systems for the commercial market sector will be economically justified, with short payback periods and substantial annual and total life cycle savings as compared to premium fuel systems. The establishment of a national CWS distribution network will certainly require a parallel growth of the demand side. This growth must be through an increase in the use of slurry in the utility and industrial sectors as well as the commercial market sector. Until that time, niche markets are available which can take advantage of their proximity to the coal mines or utilities with slurry production capabilities.

6. CONCLUSIONS AND COMMERCIALIZATION

During this development program, a complete, integrated, prototype coal water slurry (CWS)-fired space heating system for the commercial market sector was designed, built, tested, and demonstrated. The system has achieved the following program requirements:

- Successful operation with input rates ranging from 1 to 5 million Btu's per hour.
- Combustion efficiencies in excess of 99% with Eastern Kentucky coal and 98% with Illinois coals.
- Response time to full-load operation on CWS from an idle condition in less than 15 minutes, and CWS firing from a cold start in less than one hour.
- Steady state thermal efficiencies of greater than 80%.
- Completely automated-unattended operation.
- Integration with conventional firetube boilers for retrofit capability.
- Safe and reliable operation.

Additionally, the system is capable of meeting the program emission goals with coals of varying quality, including high ash, high sulfur Illinois No. 6 coal. Successful long-term and cyclic operation has demonstrated the overall technical viability and reliability of the system.

Analysis of the system economics has determined that the CWS-fired system can be competitive with conventional fuel oil and natural gas systems at moderate differential fuel costs between CWS and premium fuels. The high volume manufacturing cost of the system is predicted to be 2 to 3 times greater than conventional fuel systems, with total installation costs 2 to 2 1/2 times greater, depending on thermal output. Payback periods and total life cycle savings are highly dependent on coal sulfur levels due to sorbent and disposal costs. However, with a fuel price differential of $4 per million Btu, simple payback periods of 4 years or less can be attained utilizing a moderate sulfur content coal, such as Illinois No. 5. With predicted escalation in premium fuel prices, and with readily available CWS, the system has the potential of competing with premium fuel systems in the near future, and, until that time, will be available to satisfy niche markets where fuel is readily available and inexpensive, such as locations near coal mines where coal fines in the form of slurry is now considered a waste product.

Based on the program results, the system is deemed ready for additional demonstrations and full commercialization. Commercialization of the technology will involve a number of companies, including York-Shipley, who is currently involved in supplying heating equipment to residential, commercial and industrial users. Also, two sister subsidiaries of the Thermo Power's (Tecogen's) parent, Thermo Electron Corporation, will be involved, Holcroft/Loftus and Energy Systems. The commercialization marketing structure is shown in Figure 6.1.

At this time, although the market introduction of this technology in the U.S. is presently limited by the availability of coal slurry fuels, Tecogen is actively pursuing markets in Eastern Europe, where coal is still a predominant fuel in the commercial/industrial market sectors. In particular, Tecogen has visited a number of boiler companies in Poland, the Czech Republic, Slovakia, and Germany. The first European installation will most likely be in Poland, where Tecogen has formed a joint venture company with a district heating company and a fabrication/construction company . The company, ECOGY ZO.O., will provide advanced technologies to the Polish heating and utility industries, helping to improve the efficiency and environmental performance of these industries. Demonstration of the space heating system technology with Polish coals will be the first step in making market penetration.

In summary, this program has resulted in the development of a technology and associated hardware which will help to enable coal to regain a share of the commercial and industrial market sectors. Currently in the U.S., coal accounts for only about 10% of the total energy utilized in the commercial/industrial market, with very little coal being used in the commercial sector (<10 MMBtu/hr). The development of CWS technology capable of providing a beneficial, easy to handle, low cost coal fuel, and the availability of this low cost, maintenance free, environmentally compatible combustion equipment capable of utilizing these fuels, will help stimulate the utilization of domestic coal, reducing the need for foreign oil imports and conserving domestic gas supplies.

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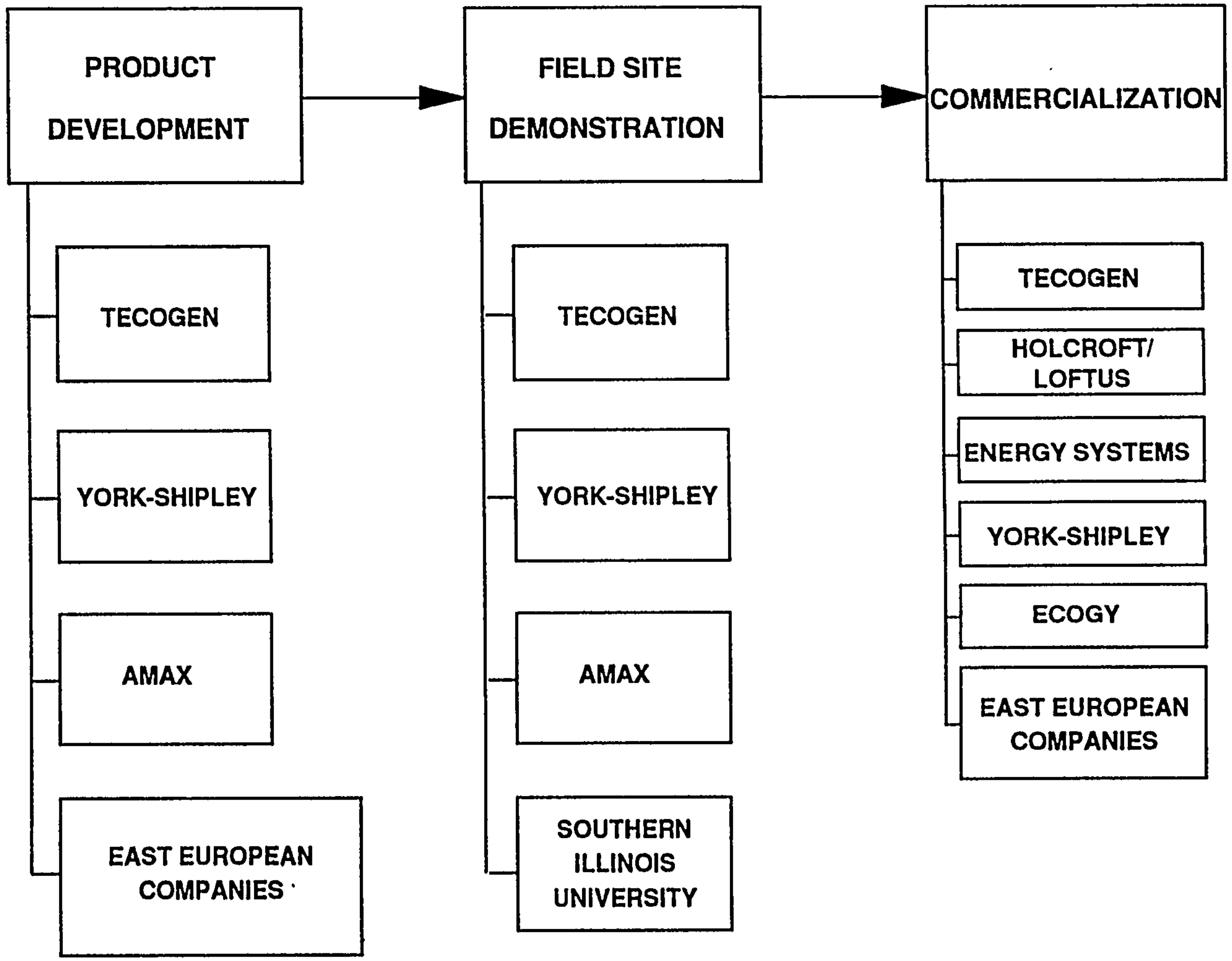

Figure 6.1 Product Development – Manufacturing-Organization Structure

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