gained more than balances the additional maintenance costs. B&W recommends limiting MMTs to the values in Figs. 20 and 21 when burning sulfur bearing fuels.

When fuel sulfur levels are high, or ambient temperatures or operating loads are low, MMTs may be unacceptably low. These situations dictate the use of active or passive cold end corrosion control methods. Active systems used to raise MMT include: 1) steam- or water-coil air heaters to preheat inlet air, 2) cold air bypass, in which a portion of the inlet air is ducted around the air heater, and 3) hot air recirculation, in which a portion of the hot outlet air is ducted to combustion air fan inlets.

Passive corrosion control methods incorporated in air heater design include: 1) thicker cold end materials, such as 11 or 14 gauge (3 or 2 mm) tubes and 18 gauge (1 mm) regenerative surface elements, 2) low or high alloy cold end surface materials which have at least twice the corrosion life of carbon steel, 3) nonmetallic coating, such as porcelain enamel, teflon, or epoxies on cold elements, 4) nonmetallic cold end surface materials such as extruded ceramic in regeneratives and borosilicate glass tubes in tubulars, and 5) tubular air heater cold end tube arrangements which maximize MMT by providing higher gas flow velocities.

Plugging and cleaning

Plugging is the fouling and eventual closing of heat transfer flow passages by gas-entrained ash and corrosion products. It can occur at the air heater hot end but is most common at the cold end where ash particles adhere to acid moistened surfaces. Plugging increases air heater pressure drop and can limit unit load when fan capacity is reached at less than full load. Air heater deposits are controlled and removed by sootblowing, cold end temperature control, surface design, off-line cleaning and furnace additives depending upon the particular application.

Erosion

Heat transfer surfaces and other air heater parts can suffer erosion damage through impact of high velocity, gas-entrained ash particles. Erosion usually occurs near gas inlets where velocities are highest. However, areas near seals in regenerative air heaters can also be damaged as ash is accelerated through seal gaps. The undesirable effects of erosion are structural weakening, loss of heat transfer surface area and perforation of components which can cause air to gas or infiltration leakage. Erosion rate is a function of velocity, gas stream ash loading, physical nature of ash particles and angle of particle impact. It is controlled by reducing velocities, removing erosive elements from the gas stream, or using sacrificial material.

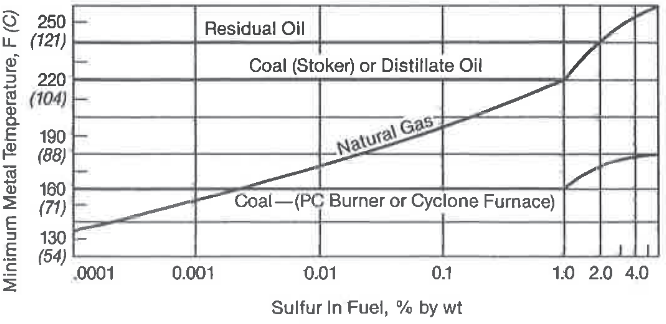


Fig. 20 Recuperative air heater cold end MMT limits when burning sulfur bearing fuels.

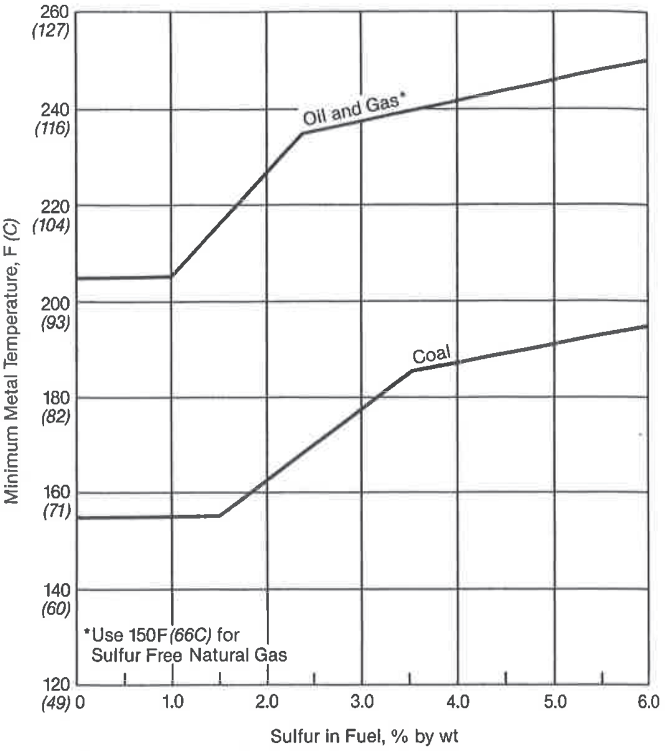


Fig. 21 Regenerative air heater cold end MMT limits when burning sulfur bearing fuels.

In the design stage, air heaters used with fuels containing highly erosive ash can be sized to limit gas inlet velocities to 50 ft/s (15 m/s). Inlet flues can also be designed to evenly distribute gas over the air heater inlet to eliminate local high velocity areas. Dust collectors, or strategically located screens and hoppers, may be used ahead of air heaters to remove some of the ash. In existing problem air heaters, flow distribution baffles may be installed to eliminate local high velocities, sacrificial materials such as abrasion resistant steel or ceramics may be placed over critical areas, or parts can be replaced with thicker materials for longer life.

Erosion in tubular air heaters frequently occurs within about 1 ft (0.3 m) of the gas inlet end due to turbulence as gas enters the tubes. Replaceable sacrificial sleeves may be installed in tube ends or egg crate-type flow straightening grids can be installed at tubular air heater inlets to reduce erosion.

Fires

Air heater fires are rare but do occur, particularly in regenerative units. They may be severe enough to completely destroy an air heater and are detected by thermocouples as well as special early warning systems. Fires usually start near the cold end, which can be fouled with unburned combustible materials. Most fires occur during startup as unburned fuel oil deposited on ash fouled heating surfaces is ignited. Leaking bearing lubrication equipment and heavy accumulations of flyash are also fire hazards. Fires can be avoided by maintaining a clean air heater and proper tuning of boiler firing equipment. Frequent sootblowing during startup and just before shutdown is a strongly recommended fire prevention practice.

Utility applications

Gas to air recuperative and regenerative air heaters are usually used in utility units, primarily to enhance unit efficiency. Small increments of increased efficiency in large units amount to substantial fuel savings. Utility units generally use multiple air heaters for plant arrangement convenience, type of firing and maximum unit availability.

Pulverized coal-fired units require two streams of hot combustion air, i.e., primary air supplied at high pressure to pulverizers and secondary air supplied at lower pressure directly to burners. Two basic air flow systems are used, hot primary air and cold primary air. Each system uses air heaters. In the hot primary air scheme, used for smaller units, about one third of the combustion air heated in a secondary heater is ducted to hot primary air fans, where it is boosted in pressure and passed to the pulverizers; the remaining two thirds is ducted to the burners. The cold primary air system uses separate air heaters supplied by separate primary and secondary (forced draft) fans. In some units, the primary and secondary air are heated in a single regenerative unit.

If separate regenerative primary and secondary air heaters are used, the primary air heaters, which operate at high air to gas pressure differentials, exhibit twice as much leakage as the secondary units. For this reason, low leakage recuperative air heaters may be used for primary air heating and regeneratives may be used for secondary air heating.

Recuperative and regenerative air heaters are used on oil- and gas-fired units. In general, regardless of fuel type, larger units use regenerative air heaters because of their smaller size and lower initial cost. However, for air to gas pressure differentials above 40 in. wg (10 kPa), in fluidized bed applications for example, recuperative air heaters are usually preferred.

Industrial applications

Industrial units fire a variety of fuels such as wood, municipal refuse, sewage sludge and industrial waste gases as well as coal, oil and natural gas. As a result, many air heater types are used. In the small units, tubular, plate, heat pipe and cast iron heaters are widely used. Fuels fired on stoker grates, such as bituminous coal, wood and refuse, do not require high air temperatures, therefore water- or steam-coil air heaters can be used.

Environmental heat exchanger application

For environmental reasons, emission of certain fossil-fired combustion products may be limited by law. (See Chapter 32.) Systems developed to limit emissions of two objectionable flue gas constituents, NO_x and SO_2, may require the use of specially modified heat exchangers.

NO_x removal

Noncombustion NO_x reduction systems introduce ammonia into flue gas streams. The ammonia (NH_3) reacts with NO_x thermally at high temperatures and in the presence of a catalyst at lower temperatures to form molecular nitrogen (N_2) and water. NH_3 also reacts with some of the SO_3 in the flue gas to form ammonia-sulfur compounds which condense at temperatures below 530F (277C). Because air heaters or gas coolers are usually downstream of NO_x reduction equipment, the heat exchanger surface is subject to rapid fouling and increased corrosion potential, particularly in the 510 to 340F (266 to 171C) range. Regenerative heat exchangers used in these situations are designed with special features to minimize plugging and corrosion. These features include a minimum number of surface layers to minimize plugging between layers; heavy gauge, low alloy, corrosion resistant or enamel coated surface material for long corrosion life; open profile heating surface design for ease of cleaning; and hot and cold end sootblowers. Heat exchangers with these features can operate reliably without off-line water washing for a year or more. As discussed in Chapter 34, some regenerative air heaters have been modified to simultaneously serve as selective catalytic NO_x reduction systems.

SO_2 reduction

When sulfur emission reduction is required, flue gas desulfurization (FGD) systems are frequently used. These systems remove SO_2 from the flue gas by reaction with injected compounds such as limestone. In most cases, the scrubbed flue gas exits the FGD system at a saturation temperature of 120 to 130F (49 to 54C) before entering the stack. In cases where acid dew point corrosion of flues and stack liners is a concern or increased gas buoyancy is needed to improve stack plume dispersal, gas exiting the FGD system is reheated to 180F (82C) or higher. Regenerative and recuperative heat exchangers, similar to those used for air heating, are used for this application.

Bibliography

Dubbel's Taschenbuch für den Maschinenbau, 11th Edition, 1958.

McAdams, W.H., *Heat Transmission*, 3rd ed., McGraw-Hill, New York, 1954.

Ledinegg, M., *Dampferzeugung*, Dampfkessel, Feuerungen Springer Verlag-Wien, 1952.

Mayer, E.H., and McCarver, G.M., *Economizer Technology for Utility and Industrial Boilers, Course for the Center for Professional Advancement*, E. Brunswick, New Jersey, 1991.

Chapter 27
Waste-to-Energy Installations

The disposal of garbage is a problem that has been with us since civilization began. At various times throughout history, composting, animal feed, landfill and incineration have all been popular disposal methods. Today, refuse disposal methods are determined by cost and the effect on our environment.

The most common means of refuse disposal is still landfilling. Even in the late 1970s, nearly all of the refuse generated in North America was landfilled. Incineration with no heat recovery was a popular option that became economically unacceptable with the advent of environmentally responsible air pollution regulations and inexpensive landfill alternatives.

In Europe and Japan, where new landfill sites were less available, incineration continued as a viable option and those plants became the predecessors of today's refuse-to-energy plants. Heat recovery was added in the form of waste heat boilers which were originally hot water boilers and later low pressure and temperature steam boilers. These incinerators with waste heat boilers then evolved into waterwall boilers with integral stokers.

Refuse-fired boiler design parameters and operating characteristics are strongly affected by the components of the refuse, which change with time. The components also vary greatly by location. In North America, typical municipal solid waste (MSW) is high in paper and plastics content (Fig. 1) and typically has a lesser moisture content and greater heating value than that found worldwide. In a less industrialized country the refuse tends to have a greater moisture content and lesser heating value. Table 1 shows representative refuse analyses ranging from 3000 to 6000 Btu/lb (6978 to 13,956 kJ/kg) higher heating value (HHV) basis.

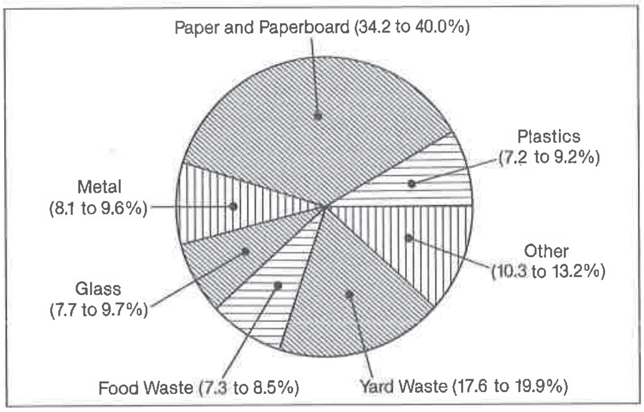


Fig. 1 U.S. municipal solid waste generation — 1990.

In the United States (U.S.) and North America, the refuse characteristics have changed dramatically in a short period of time. With more and more convenience foods, plastics, packaging, containers, and less food scraps due to home garbage disposals, the average refuse heating value has increased and the moisture content has decreased (Table 2). As more recycling programs are implemented, the analysis will continue to change. As glass, aluminum and other metals are recycled the refuse

Table 1
Range Of As-Received Refuse Fuel Analysis

Weight Percent As-Received

HHV, Btu/lb (kJ/kg)	3,000 (6,978)	3,500 (8,141)	4,000 (9,304)	4,500 (10,467)	5,000 (11,630)	5,500 (12,793)	6,000 (13,956)
Carbon	16.88	19.69	22.50	25.32	28.13	30.94	33.76
Hydrogen	2.33	2.72	3.10	3.49	3.88	4.27	4.66
Oxygen	12.36	14.42	16.49	18.55	20.62	22.68	24.75
Nitrogen	0.22	0.26	0.30	0.34	0.38	0.42	0.46
Sulfur	0.15	0.18	0.21	0.24	0.27	0.30	0.33
Chlorine	0.34	0.38	0.42	0.46	0.50	0.54	0.58
Moisture	35.72	32.35	29.98	28.60	25.22	22.85	21.46
Ash	32.00	30.00	27.00	23.00	21.00	18.00	14.00
Total	100.00	100.00	100.00	100.00	100.00	100.00	100.00

Table 2
U.S. Refuse Trends

Increasing heating value per ton of refuse
1960 — 4,200 Btu/lb (9,769 kJ/kg)
1980 — 4,500 Btu/lb (10,467 kJ/kg)
2000* — 5,200 Btu/lb (12,095 kJ/kg)

More paper and paperboard
33% in 1970
41% in 2000

More plastics
2.7% in 1970
9.8% in 2000

Less food wastes
11.5% in 1970
6.8% in 2000

*Estimate

heating value will increase; as paper and plastics are recycled the heating value will decrease.

In 1990 approximately 490,000 t (444,521 t_m) per day of MSW were generated in the U.S. About 13% of that total was recycled, 15% sent to refuse-to-energy facilities, and the balance landfilled. Early in the 21st century this is expected to reach 40% for recycling and 50% for refuse-to-energy facilities. The growth of refuse-to-energy facilities in the U.S. accelerated in the 1980s (Fig. 2) due to the growing disposal costs for landfills and a government-created market for the sale of electric power.

As old landfills closed, new landfills became more difficult and costly to open and tended to be located farther from the source of the refuse, increasing transportation costs. Concerns about ground water contamination resulted in more expensive landfill designs with several containment layers and leachate monitoring and control systems. The passage of the Public Utility Regulatory Policies Act of 1978 (PURPA) required public utilities to purchase the electric power generated by refuse-to-energy plants. This created a revenue flow that helped offset the inherent high capital cost of these plants. These market forces resulted in a proliferation of refuse-to-energy facilities in the northeast U.S. where the costs of landfill and other disposal options were the highest, and selectively throughout North America in response to local environmental or economic factors.

Refuse disposal is a major problem worldwide and there is no single solution. An environmentally sound refuse disposal program includes generating less refuse, recycling components that can be economically reused, combustion of the balance of the refuse (including the efficient generation of electric power), and the landfill of the resulting ash.

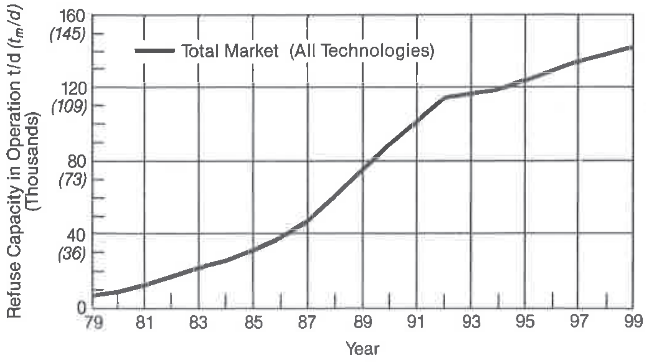


Fig. 2 U.S. refuse-to-energy market.

Refuse combustion alternatives

Two main techniques are used for burning municipal refuse, distinguished by the degree of fuel preparation. The first technique, known as mass burning, uses the refuse in its as-received, unprepared state (Fig. 3). Only large or noncombustible items such as tree stumps, discarded appliances, and other bulky items are removed. Refuse collection vehicles dump the refuse directly into storage pits. Overhead cranes equipped with grapples move the refuse from the pit to the stoker charging hopper. Hydraulic rams move the refuse onto the stoker grates. The combustible portion of the refuse is burned off and the noncombustible portion passes through and drops into the ash pit for reclamation or disposal.

The second burning technique uses prepared refuse, or refuse-derived fuel (RDF), where the as-received refuse is first separated, classified, and reclaimed in various ways to yield salable or otherwise recyclable products (Fig. 4). The remaining material is then moved to the boiler feeders and fed through multiple feeders onto a traveling grate stoker. The RDF is burned, part in suspension and part on a stoker. More finely shredded RDF can also be fired in suspension to supplement conventional fuels in large boilers used for power generation.

Corrosion

Combustion products from municipal refuse are very corrosive. The components that are present in coal, oil and other fuels that contribute to corrosion, as well as to high slagging and high fouling, are all present in refuse (Table 3). Corrosion in refuse-fired boilers is usually caused by the chlorides which deposit on the furnace, superheater and boiler tubes. Several modes of chloride corrosion may occur:

1. corrosion by hydrochlorides (HCl) in the combustion gas,
2. corrosion by NaCl and KCl deposits on tube surfaces,
3. corrosion by low melting point metal chlorides (mainly $ZnCl_2$ and $PbCl_2$), and
4. out of service corrosion by wet salts on the tube surface.

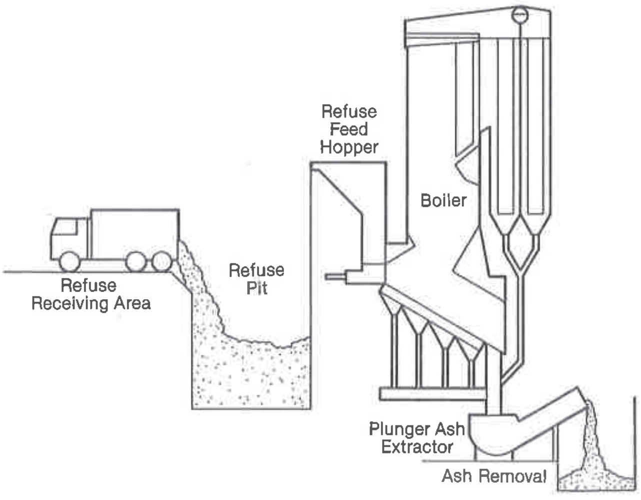


Fig. 3 Mass burning schematic.

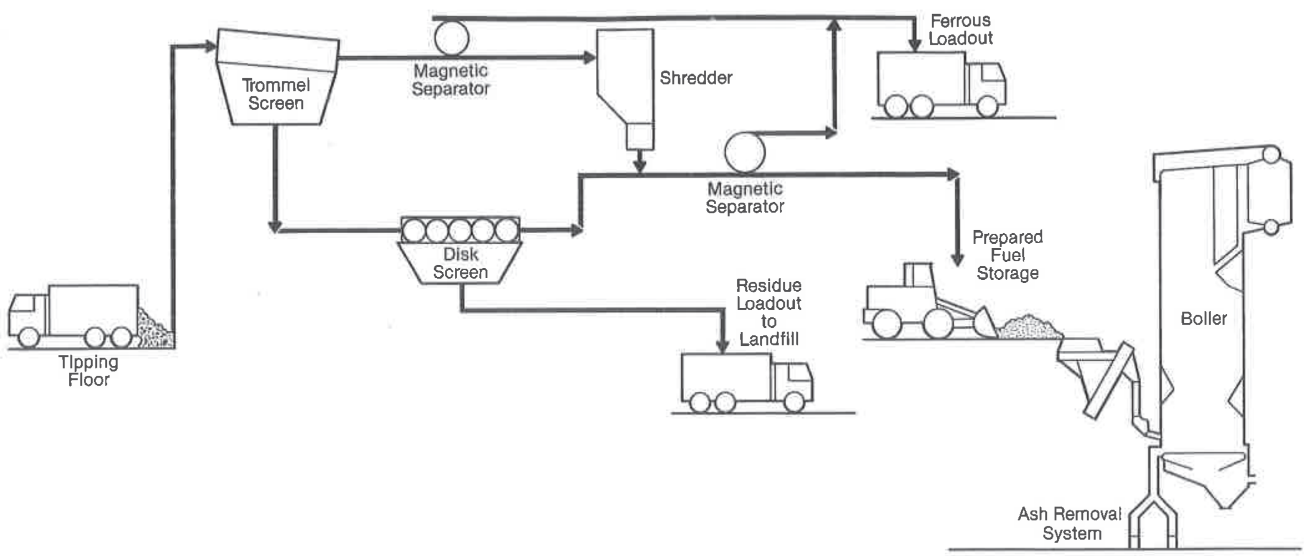


Fig. 4 RDF burning schematic.

The rate of tube metal loss due to corrosion is temperature dependent with high metal temperatures correlating with high rates of metal loss (Fig. 5). Refuse boilers operating at higher steam pressures have higher temperature saturated water in the furnace tubes and, therefore, these furnace tubes have higher metal temperature. Superheater tube metal temperatures are directly related to the steam temperature inside the tubes. In both cases, it is the temperature of the water or steam inside the tube that largely controls the tube metal temperature, rather than the temperature of the flue gas outside of the tube.

Furnace-side corrosion can be aggravated by poor water chemistry control. If water-side deposits are permitted to form, tube wall metal temperatures will rise and furnace corrosion will be accelerated. Standards for feedwater and boiler water quality are based on boiler operating pressures. These standards are no more stringent for refuse-fired units than for other fuels. However, the maintenance of feedwater and boiler water quality, and adherence to those standards, is more critical on refuse-fired boilers due to the highly corrosive nature of the fuel.

Lower furnace corrosion

The lower furnace environment of both mass-fired and RDF-fired units is constantly changing between an oxidizing atmosphere (an excess of O_2 beyond that needed for combustion) and a reducing atmosphere (a deficiency of O_2 below that needed for combustion) which can rapidly accelerate corrosion. Therefore, some form of corrosion protection is needed. Typically, the area of protection will encompass all four walls up to 30 ft (9.1 m) above the grate where there is reasonable assurance that oxidation zones are predominant.

Table 3
Corrosive Constituents in Fuels

Coal	Oil	Refuse	
Sodium	Sodium	Sodium	Chloride
Sulfur	Sulfur	Sulfur	Lead
Potassium	Vanadium	Potassium	Zinc
		Vanadium	

Mass-fired units

Virtually all mass-fired refuse boilers incorporate some type of pin stud and silicon carbide (SiC) refractory to protect the membraned lower furnace walls (Fig. 6). The quality and physical characteristics of the silicon carbide refractory must be maintained through proper application and curing. Lack of control during installation will result in spalling, deterioration and increased maintenance. The refractory material should have high thermal conductivity rates to minimize reducing the effectiveness of the water-cooled surface it is protecting. However, such characteristics may reduce its resistance to erosion as experienced along the grate line due to the scrubbing action of the refuse fuel and ash as it moves along the grate to the ash discharge. Increased erosion-resistant SiC materials are available for these zones. They do, however, have lower thermal conductivities.

A better alternative near the grate line is the use of armour blocks or refractory blocks, rigidly attached to the furnace walls. These blocks extend up the full height of the charging hopper opening which is about 4 ft (1.2 m)

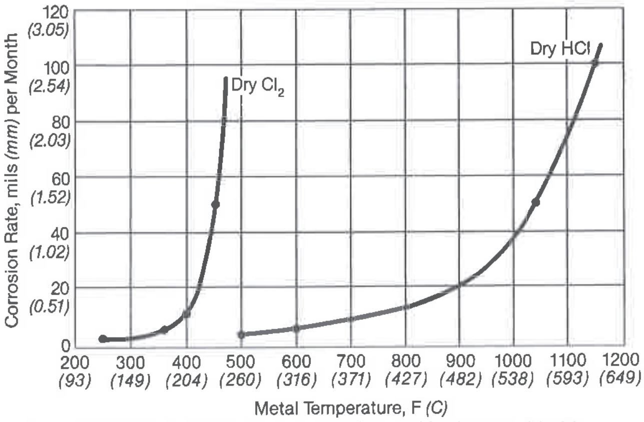


Fig. 5 Corrosion of carbon steel in chlorine and hydrogen chloride.

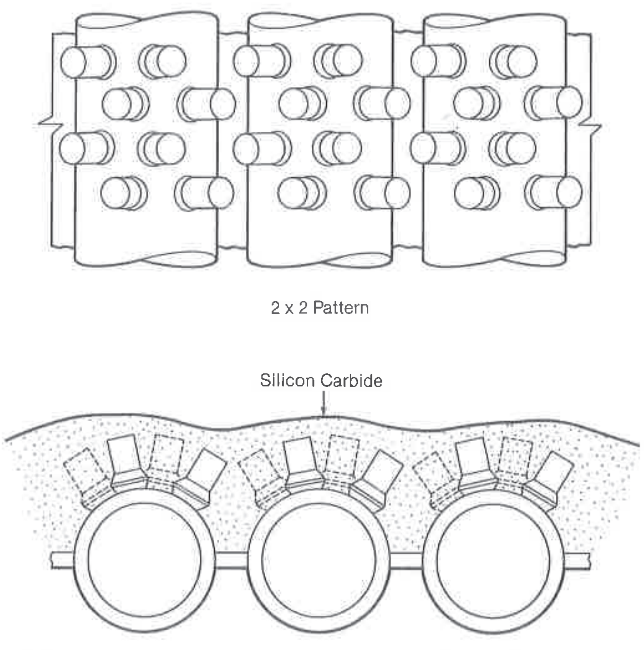


Fig. 6 Lower furnace studs and refractory, mass-fired unit.

high at the front of the furnace and tapers off to about 1 ft (0.3 m) high at the ash discharge end (Fig. 7). These blocks are designed for easy replacement as they wear.

The pin stud pattern, pin stud length and pin stud diameter must be carefully chosen for its ability to hold the refractory in place and to maximize the heat transfer through the stud to the furnace wall tubes. This, in turn, serves two purposes. One is to provide maximum cooling to keep as low a refractory temperature as possible. Maintaining a low refractory surface temperature has a dramatic effect on refractory life, furnace wall fouling and maintenance costs. Secondly, with more heat removed in this lower furnace area, less heating surface is required in the upper furnace to achieve the desired flue gas temperature leaving the furnace.

RDF-fired units

Prior to the late 1980s, RDF boilers were installed with bare carbon steel tubes in the lower furnace and no corrosion protection. It was thought that with the more even combustion with a processed fuel, corrosion would not be a concern in the lower furnace. Early units, operating at low steam pressure and temperature, did not experience corrosion problems. However, as higher pressure and temperature units went into operation, corrosion increased and lower furnace protection was needed.

The same pin stud and refractory design used on mass-fired units has also been tried on RDF units. This solved one problem but created another. Inherent in the RDF combustion process is a high degree of suspension firing and high flame temperatures in the lower furnace. When pin studs and refractory are applied, the lower furnace tubes are insulated, resulting in less heat transfer and hotter flue gas temperatures in the lower furnace. This, in turn, can result in significant slagging on the refractory wall surface. Pin stud and refractory was tried at two RDF facilities. However, increased furnace slagging resulted, and eventually the pin studs and refractory were removed.

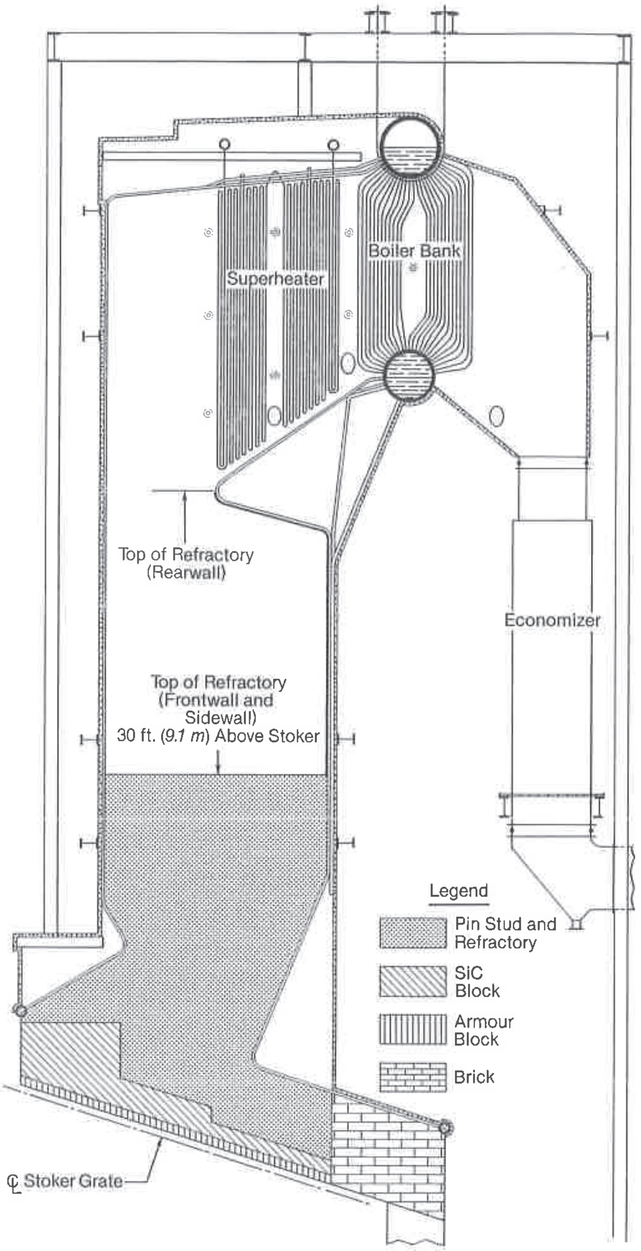


Fig. 7 Refractory type and location, mass-fired unit.

What was needed was a material that was resistant to the chloride corrosion found in refuse boilers while not insulating the lower furnace tubes. Babcock & Wilcox (B&W) pioneered the use of Inconel material as a solution to this lower furnace corrosion problem. In 1986, following rapid corrosion of the bare carbon steel tubes, the lower furnace of the Lawrence, Massachusetts unit was covered with a weld overlay of Inconel material. This overlay proved to be effective in minimizing corrosion in the lower furnace. Based on this early experience the industry followed B&W's lead and Inconel weld overlay was field applied to the lower furnace of a number of operating boilers.

For the RDF boilers supplied as part of the refuse-to-energy plant in Palm Beach County, Florida, the decision was made to add the Inconel protection prior to manufacture. A bimetallic tube construction was used consisting of a carbon steel inner tube co-extruded with an Inconel outer tube (Fig. 8). This allows for a more uniform protective coating than does a weld overlay. These boilers went into operation in 1989 and the Inconel bimetallic tubes have experienced no corrosion in their initial years of operation. Today the bimetallic tube is the industry standard for lower furnace corrosion protection in RDF-fired boilers.

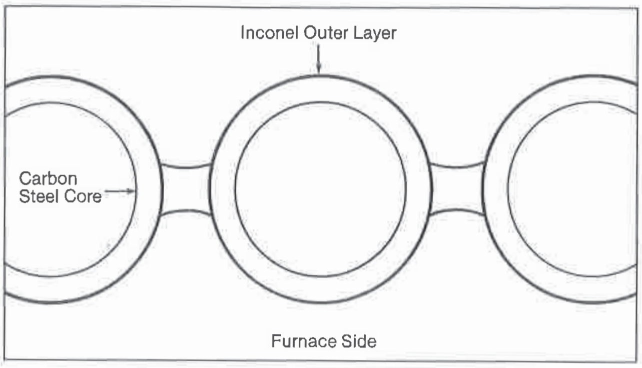


Fig. 8 Bimetallic tube.

Mass burning

Mass burning is the most common refuse combustion technology worldwide. There are more than 1600 mass burn units in operation throughout the world, predominantly in Europe and Japan. When the market for refuse-to-energy facilities expanded rapidly in the U.S. in the early 1980s, many of these refuse plants adopted this well proven mass burning technology (Fig. 9). However, some major differences in the U.S. application resulted in some operational problems. U.S. applications tend to require large units (Fig. 10) to accommodate larger regional facilities instead of the small local and community plants typical of European and Japanese applications. U.S. plants were designed to operate at significantly higher operating pressures and temperatures to take advantage of the economics of production and sale of electric power while typical non-U.S. applications produced hot water and low pressure steam for heating applications. U.S. refuse fuel typically has a higher heating value and lower moisture content. Finally, U.S. units began to be installed at a time when environmental concerns were increasing.

The net result of these characteristics of the market resulted in many early U.S. refuse units experiencing operating problems related to:

1. high rates of slagging in the furnace,
2. higher gas temperature leaving the furnace resulting in overheating of superheaters and excessive fouling in the convection section,
3. tube failures from accelerated corrosion that were metal temperature related, and
4. concerns about the creation of dioxins (Polychlorinated Dibenzoparadioxin, PCDD) and furans (Polychlorinated Dibenzofurans, PCDF) during the combustion process

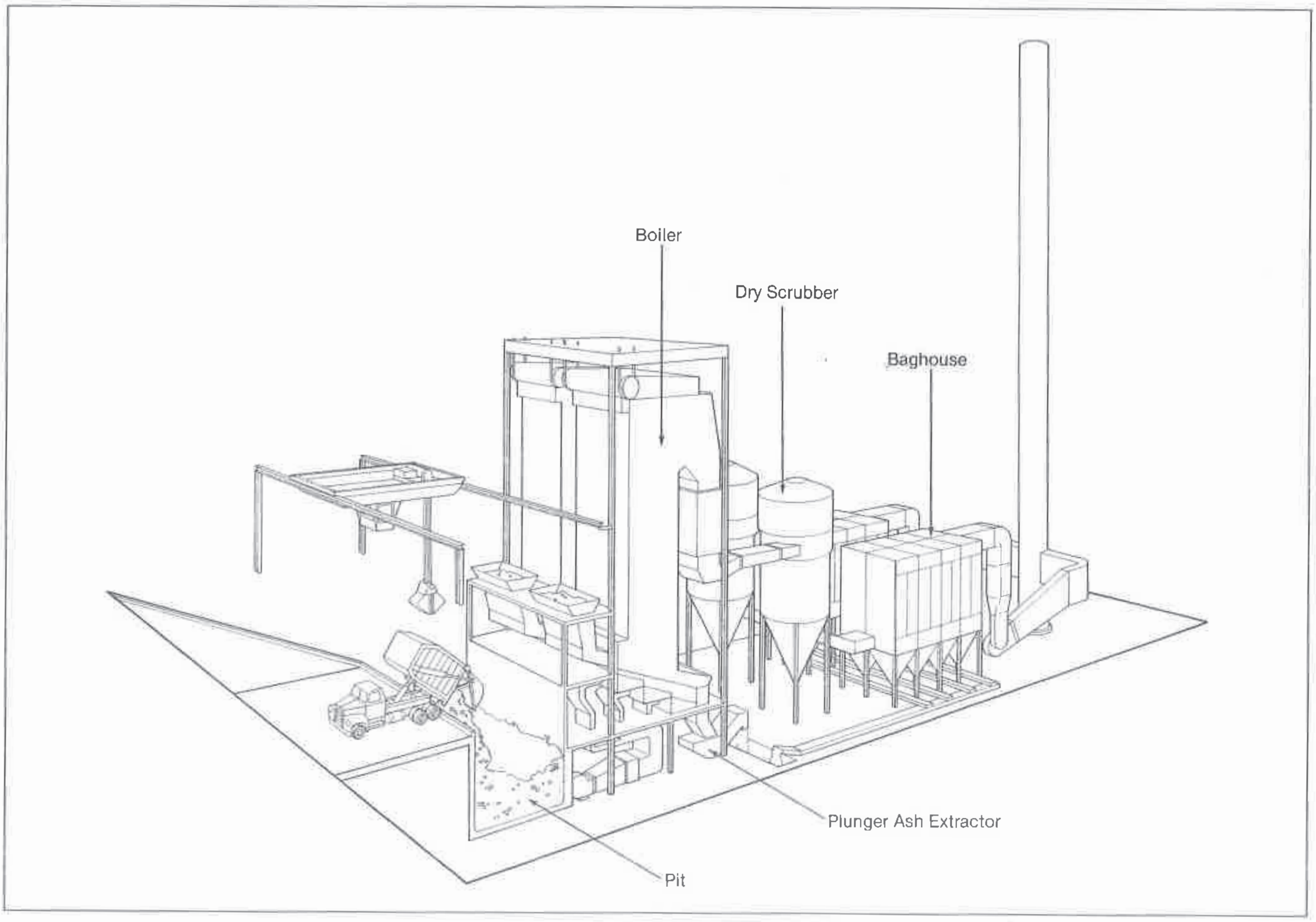


Fig. 9 Typical mass burning refuse-to-energy system.

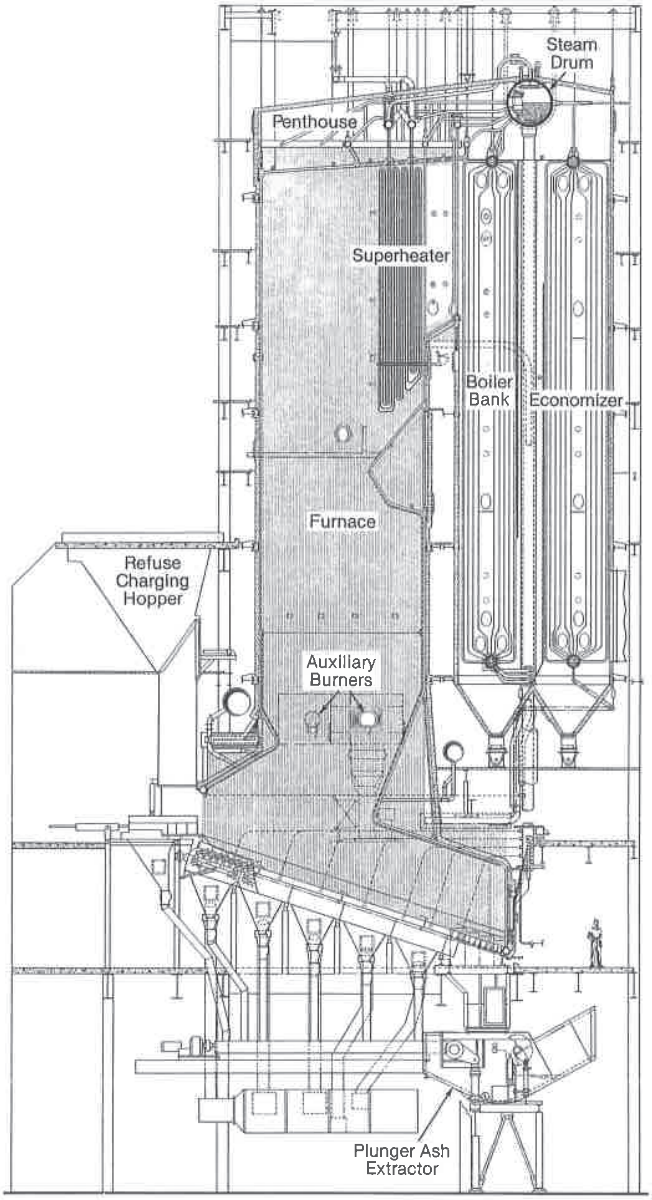


Fig. 10 Typical mass burning unit.

that were related to less than optimum combustion systems, particularly less than optimum turbulence and mixing of fuel and air in the lower furnace.

Boiler plant sizing

A refuse plant must be sized to handle the physical amount of refuse that is delivered to that plant, regardless of the refuse heating value. A refuse boiler, on the other hand, is a heat input device and must be sized for the maximum heat input expected. When designing a refuse boiler you need to know the design tons per day of refuse to be combusted and the typical range of heating values that is expected for the refuse in that location.

The boiler is typically designed for the maximum ton per day input at the maximum refuse heating value. A 1000 t/d (907 t_m/d) refuse plant is actually not the same size plant in all locations. A plant in the Northeast U.S. would typically be designed to handle refuse at heating values as high as 5500 Btu/lb (12,793 kJ/kg), or 458 x 10^6 Btu/h (134 MW_t) total heat input to the boilers. At the other extreme, a plant in a less industrialized country would be designed to handle refuse with a heating value in the range of 3500 Btu/lb (8140 kJ/kg), or 292 x 10^6 Btu/h (85.6 MW_t) total heat input. Both are 1000 t/d (907 t_m/d) plants, but one has refuse boilers that have a 50% larger capacity.

For many of the early U.S. plants, good data were not available on the true range of heating values of the refuse. Refuse boilers were sized for typical heating values of 4500 Btu/lb (10,467 kJ/kg). When the actual heating values were found to be as high as 5200 to 5500 Btu/lb (12,095 to 12,793 kJ/kg), the boilers were actually undersized and could not process the available refuse on a ton per day basis.

Stoker capacity

A refuse stoker has both a heat input limit and a ton per day of refuse limit. If a typical 1000 t/d (907 t_m/d) refuse plant has two 500 t/d (454 t_m/d) boilers, and the design refuse heating value is 5000 Btu/lb (11,630 kJ/kg), each boiler would have a maximum heat input limit of 208.3 x 10^6 Btu/h (61.1 MW_t). If the actual refuse heating value is above 5000 Btu/lb (11,630 kJ/kg), the maximum heat input limit can not be exceeded and therefore the unit's t/d capacity would be reduced below 500 t/d (454 t_m/d). On the other hand, if the actual refuse heating value is below 5000 Btu/lb (11,630 kJ/kg), then the unit could actually process more than 500 t/d (454 t_m/d) of refuse, up to the maximum ton per day limit of that stoker.

The ton per day limit is usually set by a refuse capacity per unit of width, a limit for optimum fuel feed and distribution, or a weight per square foot (m^2), a structural limit. These limits are in the range of 30 t/d (27 t_m/d) per front foot (0.3 m) of width and 65 lb/h ft^2 (2.74 kg/h m^2) of grate area. The grate surface area is set by a grate release rate generally in the range of 300,000 to 350,000 Btu/h ft^2 (946,350 to 1,104,080 W/m^2), but may be lower for low heating value, high moisture fuels. The stoker width and depth are also related to the specific fuel.

A high heating value, low moisture fuel would require a wider, less deep stoker because the fuel will tend to burn more rapidly. A low heating value, high moisture fuel would require a narrow, deeper stoker because more residence time on the stoker is usually needed. The combination of all these criteria will set the maximum ton per day rating of the stoker.

There is also a minimum load that can be effectively handled on a given stoker. This load is also set by both a ton per day limit (minimum fuel inventory on the grate) and a heat input limit (minimum heat input for good combustion).

All of these limits can be incorporated into a capacity diagram, which provides the operator with the boundary limitations around a family of heating value curves. Fig. 11 is such a diagram for a typical 500 t/d (454 t_m/d) boiler burning 5000 Btu/lb (11,630 kJ/kg) refuse.

Stoker design

The combustion of MSW requires a rugged, reliable stoker to successfully convey and burn unsorted refuse. Most stokers use some variation of a reciprocating grate action, with either forward moving or reverse acting grate movement. Some arrangement of moving and stationary grates is used to move the refuse through the furnace and allow time for complete combustion.

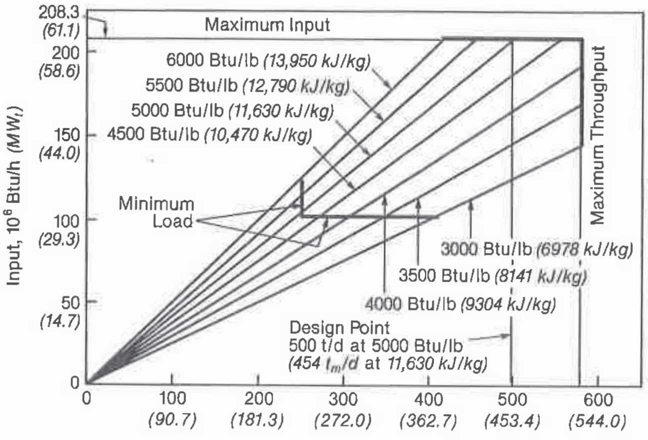


Fig. 11 Stoker capacity diagram.

The stoker illustrated in Fig. 12 is typical of the forward moving reciprocating grate stoker. This grate is designed with alternate moving and stationary rows of grates in a stairstep construction with a downward slope to help move the refuse through the furnace. Each row of grates overlaps the row beneath it and the alternate rows are supported from a moving frame driven by hydraulic cylinders (Fig. 13). These grates move the refuse over the stationary grates, where it is picked up by the next row of moving grates and moved through the furnace. The action of these reciprocating grates rolls and mixes the refuse, constantly exposing new material to the high temperatures in the bed and allowing the combustion air to contact all the burning refuse.

For low heating value, high moisture refuse, drop off steps are often incorporated into the stoker design. The steps are located at the end of each grate module resulting in one to three steps depending on the overall stoker length. These steps promote a tumbling and rolling action as the burning refuse falls off the step. This type of design was used on a number of the early refuse units in the U.S. but was found to be unnecessary with the higher heating value and lower moisture refuse. In fact, it can be a detriment as the tumbling can also result in excursions of high carbon monoxide (CO) emissions.

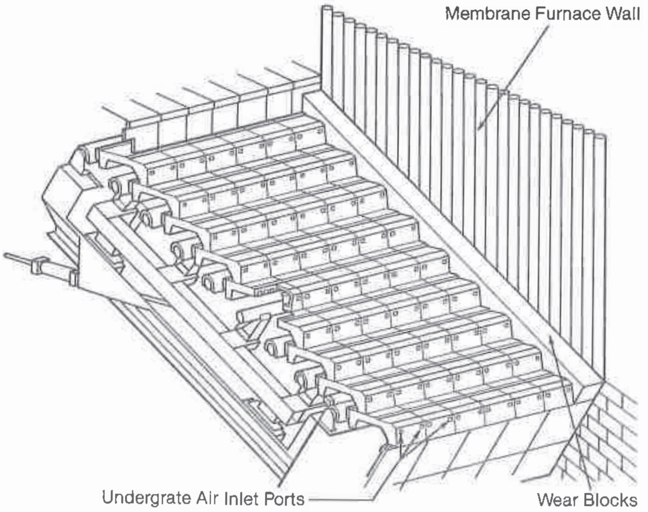


Fig. 12 Forward moving reciprocating grate stoker *(courtesy von Roll Inc.)*.

The grates are usually constructed in a series of standard modules with independent drives and air plenums. This allows the individual grate modules to be factory-assembled to limit field construction time and provide complete duplication of parts for easy maintenance and repair. This modular construction allows any size stoker to be constructed from a small number of standard modules. A typical stoker is usually from two to four modules in length and one to four modules in width. This method of construction also allows for complete zoned undergrate air control to the individual burning areas of the grate and provides complete freedom in the operating speed of the individual grate modules to provide the required feed rate along the grate for complete burnout of the fuel. This ability to control the undergrate air in multiple air zones along the width and depth of the stoker is an important factor in minimizing CO and nitrogen oxides (NO_x) emissions.

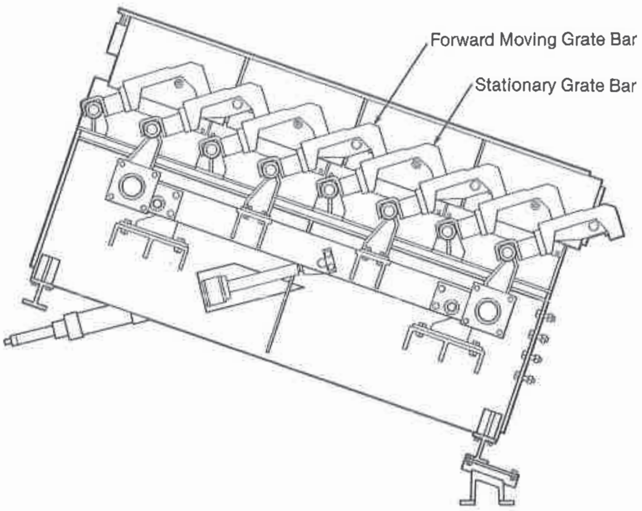


Fig. 13 Reciprocating grate, longitudinal section *(courtesy von Roll Inc.)*.

Fuel handling

The MSW delivered to the refuse plant is generally dumped directly into the storage pit. This large pit also provides a place to mix the fuel. This mixing is done using the crane and grapple to move and restack the refuse as it is dumped into the pit. This produces a fuel, in both composition and heating value, as consistent as possible for the boilers. This is an essential job for the crane operator and any time not required to feed the furnaces is used to mix the fuel. It is not uncommon for the crane operator to mix four grapple loads back into the pit for every one load that goes to the charging hopper.

Fuel feed system

Controlled feed of the fuel is necessary for good combustion to minimize CO and NO_x emissions and to maintain constant steam output. At the bottom of the charging hopper feed chute, a hydraulic ram pushes the fuel into the furnace and onto the stoker grates at a controlled rate. On larger units, multiple charging rams are used across the width of the unit to provide a continuous fuel feed with optimum side to side distribution. The hydraulic rams stroke forward slowly and then retract quickly to provide the positive continuous fuel feed. These rams are simple to control with feed rate adjustments made by either the speed of travel or the number of strokes per hour.

Combustion air system

The primary combustion air, or undergrate air, is fed to the individual air plenums beneath each grate module. A control damper at the entrance to each air plenum controls the undergrate air to each section of the grate (Fig. 14). The grate surface is designed to meter the primary combustion air to the burning refuse uniformly over the entire grate area. This is accomplished by providing small air ports or tuyères in the surface of the individual grate bars. These air ports provide openings equal to approximately 3% of the grate area which results in sufficient pressure drop of air resistance across the grate to assure good distribution of the air flow through the grate, regardless of the depth of refuse on the grate. Undergrate air systems are generally designed for 70% of the total air to be undergrate air with expected normal operation of 60%.

Because refuse contains a high percentage of volatiles, a large portion of the total combustion air should enter the furnace as secondary, or overfire, air through the furnace walls. These secondary air ports are located only in the front and rear furnace walls so that the air flow parallels the normal flow pattern through the unit. Older design units generally provided 25 to 30% of the total air as overfire air. With today's emphasis on better combustion and lower emissions, the overfire air systems are designed for 50% of the total air to be overfire air with expected normal operation at 40%.

The basic function of the overfire air is to provide the quantity of air and the turbulence necessary to mix the furnace gases with the combustion air and to provide the oxygen necessary for complete combustion of the volatiles in the lower furnace. Excess air in the furnace is usually maintained in the range of 80 to 100% and complete combustion is demonstrated by a CO value in the furnace of 100 ppm or less.

To aid in the combustion of wet fuels during extended periods of rainy weather, the air system includes steam coil air heaters designed to provide air temperatures in the range of 300 to 350F (149 to 177C) to help dry these fuels and maintain furnace temperature. These steam coil air heaters are commonly used only for the undergrate air because this is the air flow which directly aids in drying wet fuel. These air heaters must be conservatively designed with fin spacing not exceeding 4 to 5 fins/in. (1 fin/6.4 to 5.1 mm). Most plants take combustion air from the storage pit area to help minimize odors. This air is normally contaminated with dust and lint which could plug the steam coil. Some type of cleaning arrangement or filters must therefore be included to keep the steam coil clean.

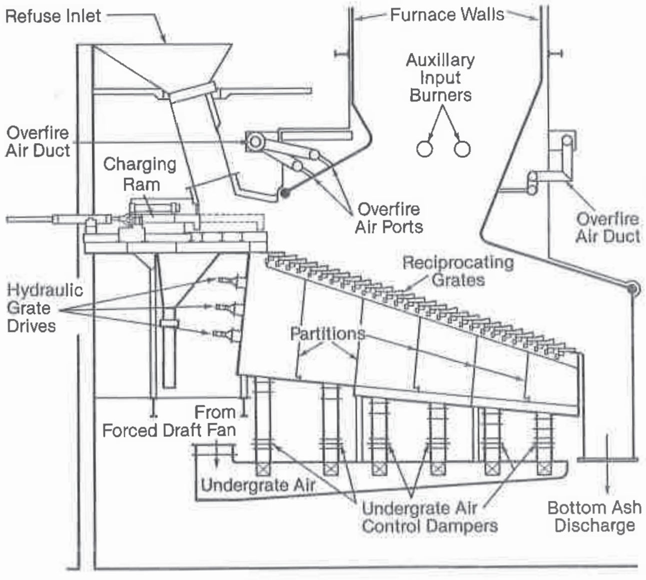


Fig. 14 Combustion air system.

When high moisture fuels are encountered, the first action by the operator is to use the steam coil air heater to provide hot air. However, for very high moisture fuels it may also be necessary to use the auxiliary fuel burners to stabilize combustion in the furnace. These cases are the exception, and in normal operation neither the auxiliary burners nor the steam coil air heater are needed for good combustion.

Ash handling systems

When refuse is burned, the ash takes the form of either light ash, called flyash, or coarse ash, which comes off the stoker. The flyash is entrained in the gas stream until it is removed in the particulate collection device or falls out into the boiler, economizer, or air heater hoppers. The stoker ash consists of ash from the fuel, slag deposits on the grate, ash from the furnace walls and, in some designs, ash from the superheater. The stoker ash is discharged through the stoker discharge chute and from the stoker siftings hoppers.

Plunger ash extractor

The ash from the stoker discharge on mass-fired units may contain large pieces of noncombustible material, in addition to the normal ash from combustion. Ash consistency can vary from fine particles to large and heavy noncombustible objects in the fuel. The ash from the stoker discharge chute falls into a water bath in the plunger ash extractor (Fig. 15) that quenches the ash and controls dusting. After the ash is quenched, a slow moving, hydraulically operated ram cycles forward and back to push and squeeze the accumulated ash up an inclined dewatering section to the discharge of the extractor. The ram cycle continues at a slow speed to push the ash out of the extractor. The dewatered ash has a moisture content of 15 to 20% as a result of the squeezing process on the incline. The lower moisture content can have an economic advantage as the cost of landfilling ash is based on total weight, which includes the weight of water in the ash.

To keep the ash system simple and to minimize costs, ash from the extractor can discharge directly into a truck or bin for final disposal. To move the ash away from the vicinity of the stoker discharge, vibrating and belt-type conveyors are used. A short vibrating conveyor is placed at the discharge of the ash extractor; its metal trough can take the impact of the oversized, noncombustible material falling from the extractor. The vibrating conveyor then transfers the ash to a belt conveyor, minimizing the wear on the belt conveyor that would occur if the extractor discharged directly onto it.

Double gate ash hopper

Double gate ash hoppers can be used (Fig. 16) in lieu of an ash extractor. The hopper has gates on the top and

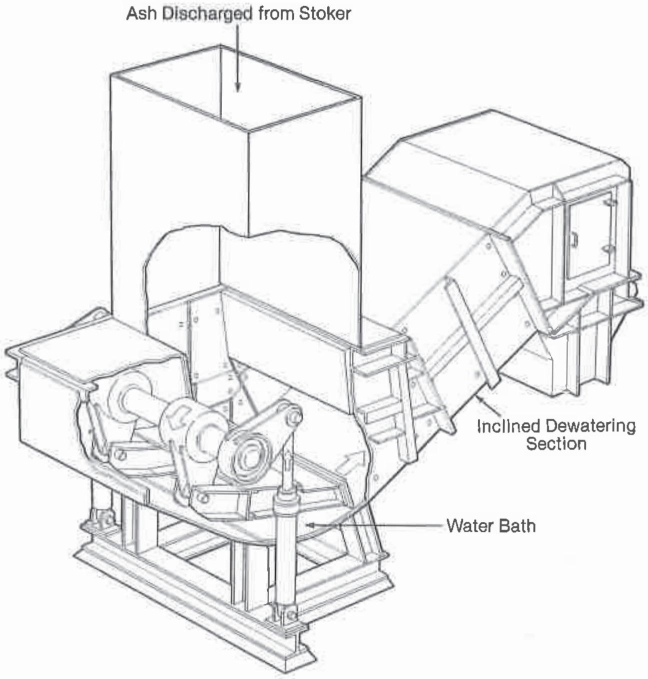


Fig. 15 Plunger ash extractor.

the bottom to control the flow of ash entering and discharging from the hopper. Water spray nozzles help quench the ash in the hopper. The ash can be discharged directly into a truck or onto a conveyor for disposal. This system is simple with low capital cost.

Scrubber, precipitator and baghouse flyash

The flyash collected in the scrubber, precipitator or baghouse hoppers can be handled by dry mechanical screw or chain-type conveyors. These units operate continuously to minimize hopper pluggage problems and they discharge onto a collecting conveyor, which is usually a dry chain type. Because the mechanical conveyors are dust-tight, but not designed to be gas-tight, separate sealing devices, such as rotary seals or double flop valves, are used. The collecting conveyor will collect the flyash discharged by all the conveyors under the rows of hoppers, and move it to a single collection point for ultimate disposal.

RDF firing

RDF technology was developed in North America as an alternative to the mass burning method. Initially, RDF was used as a supplementary fuel for large, usually coal-fired, utility boilers. For this application the RDF was finely processed and sized to 1.5 in. (38.1 mm) maximum size. The resulting RDF was nearly all light plastics and paper.

For supplemental firing, B&W guidelines call for a maximum RDF input of 20% on a heat input basis and no RDF input until the boiler is operating above 50% load. In most cases the RDF is blown into the furnace sidewalls at the pulverized coal burner elevation through an RDF burner with a fuel distribution impeller. Most of the RDF burns in suspension in the high heat input zone of the pulverized coal fire. However, some of the heavier fuel fraction falls out in the lower furnace. Dump grate stokers located in the neck of the ash hopper allow more complete burnout of these heavier pieces before they are discharged into the ash system (Fig. 17). RDF has been successfully co-fired in B&W boilers at Lakeland, Florida, Ames, Iowa, and Madison Gas & Electric in Wisconsin.

RDF has also been successfully co-fired in B&W Cyclone furnaces where the finely processed and sized RDF is injected into the Cyclone secondary air stream moving tangentially inside of the Cyclone barrel. (See Chapter 14.) This method of RDF combustion is used at the Baltimore Gas & Electric Company's Crane station in Maryland.

Dedicated RDF-fired boilers

From this supplemental fuel experience, RDF then became the main fuel for boilers specifically designed to generate full load steam flow when burning RDF (Fig. 18). In some cases where steam flow was required even when refuse was not available, the boiler was designed so that it could also reach full load on wood, coal or natural gas. More commonly there would only be auxiliary gas or oil burners for startup and shutdown.

The first boilers in the world to fire RDF as a dedicated fuel were B&W units which began operation in 1972 in Hamilton, Ontario, Canada. The first of such boilers in the U.S. went into operation in 1979 in Akron, Ohio. The boiler design was highly influenced by the proven technology of wood-fired boilers with respect to their fuel feed system, stoker design, furnace sizing and overfire air system. The transfer of this technology from wood firing to RDF firing was successful in many areas, but in other areas design adjustments were needed to accommodate the unique aspects of RDF.

The operating experience from the first generation designs at Hamilton, Akron and other plants led to second generation designs with improved RDF processing systems, fuel feed systems and boiler design. Specific improvements included the first fuel feeder designed specifically for RDF and the use of alloy weld overlay in the lower furnace for corrosion protection.

The third generation of facilities is essentially today's state-of-the-art design (Fig. 19). This boiler design has a unique lower furnace arch arrangement and an enhanced

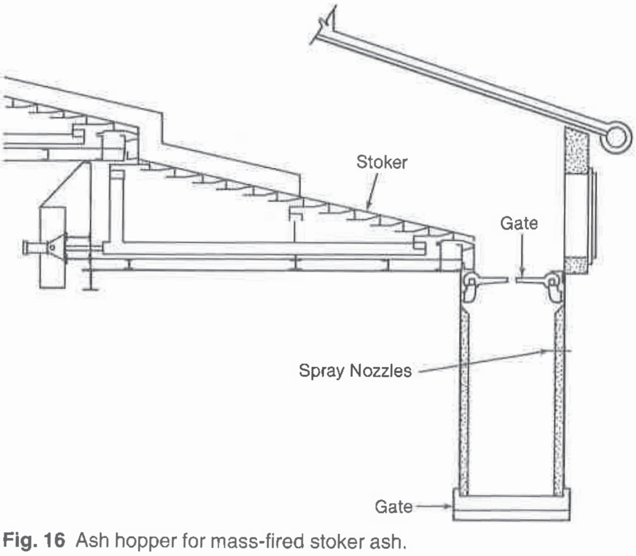


Fig. 16 Ash hopper for mass-fired stoker ash.

overfire air system to significantly improve combustion efficiency. These third generation designs also incorporate dramatically improved fuel processing systems.

RDF preparation systems

The first generation RDF processing systems were crunch and burn systems. The incoming refuse first went to a hammermill type shredder that produced an RDF with 6 x 6 in. (152 x 152 mm) top size. Ferrous metal was removed by magnetic separators. There was no other material separation and many undesirable components entered the boiler. Shredded particles of glass were embedded in wood and paper resulting in a very abrasive fuel entering the boiler in suspension. Also, the RDF was generally stored in a hopper or bin. RDF is compactible and in nearly every case, significant problems were encountered getting the RDF out of the storage bins.

Second generation RDF processing systems recognized and corrected some of the problems. The shredder for final fuel sizing was moved to the back of the processing system and some type of rough sizing shredder was used as the first piece of equipment in the system. This reduced, but did not eliminate, the problem of abrasive particles embedding in the fuel. Some size separation equipment was introduced, generally removing the small size fraction which is less than 1.5 in. (38.1 mm) composed mostly of broken glass, ceramics and dirt, which was sent to landfill. RDF was stored on the floor rather than in bins or hoppers and was moved by front-end loaders to conveyor belts. This greatly improved the reliability of fuel flow to the boiler.

In third generation RDF processing systems (Fig. 20) the first piece of equipment became a flail mill or similar equipment whose main function was to break open the garbage bags. The refuse was still size separated using a trommel or disk screen with the minus 1.5 in. (38.1 mm) size destined for landfill. Generally, a device such as an air density separator was added to remove the light fraction (paper, plastics, etc.) from this stream to achieve maximum heat recovery. Where it was economically attractive, aluminum separation was added to the plus 1.5 in. (38.1 mm.) minus 6 in. (152 mm) stream.

RDF yield

The ash content of the RDF is directly related to the yield of the processing system or the percentage of RDF produced from a given quantity of MSW. A 70% yield means that 70 t of RDF is produced for every 100 t of incoming MSW. In a processing system with a lower yield, the portion of the

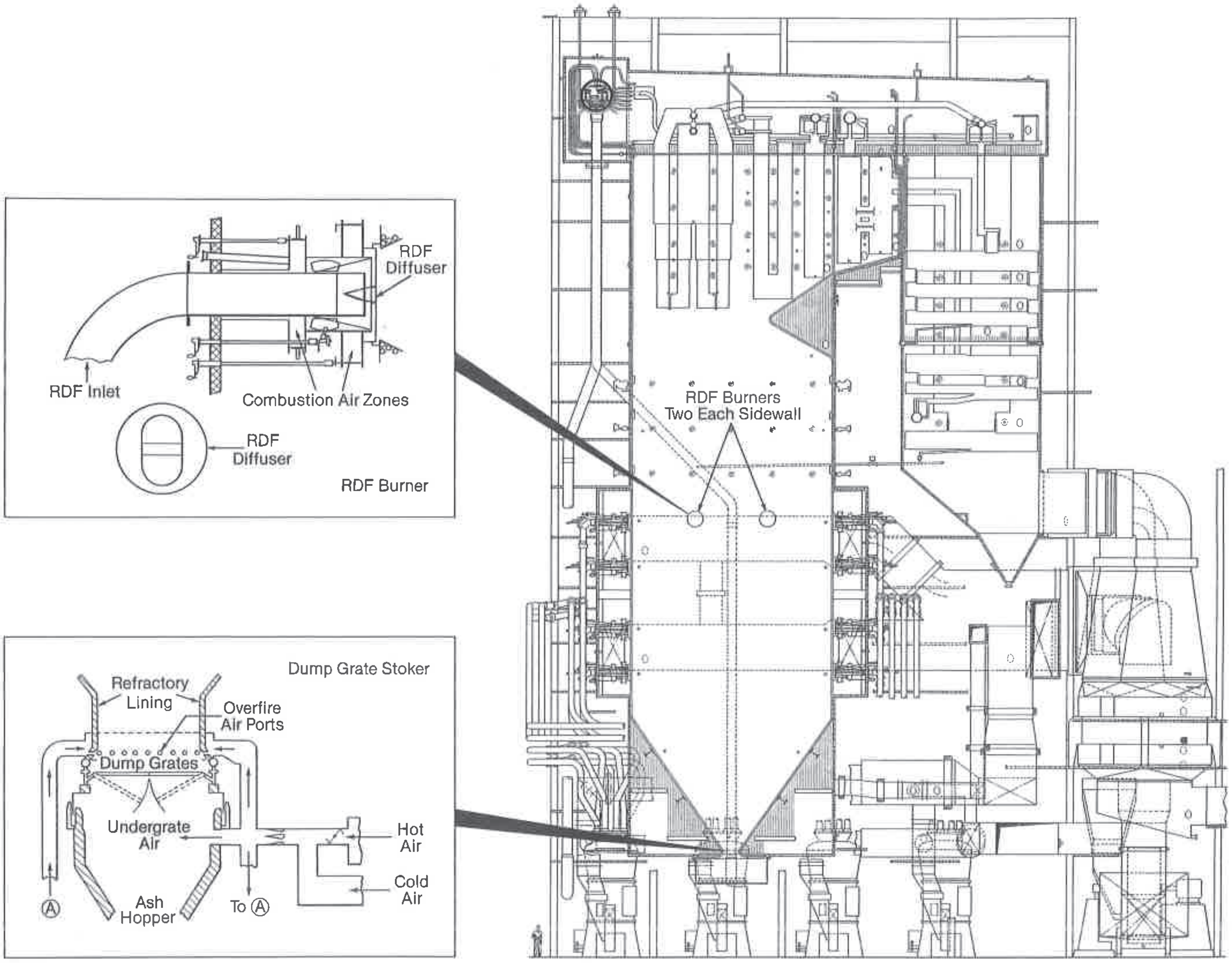


Fig. 17 Typical B&W RB type utility boiler firing RDF as a supplementary fuel.

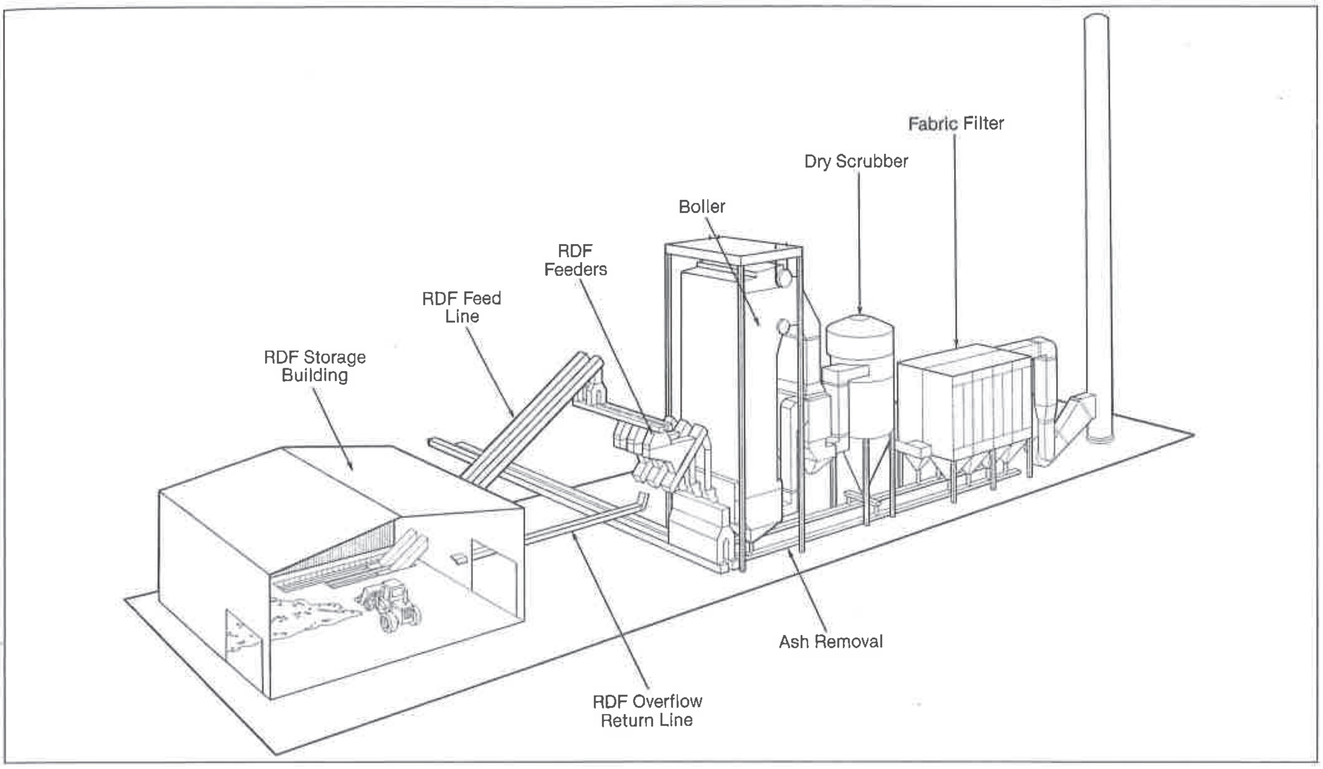


Fig. 18 Typical RDF refuse-to-energy system.

MSW that is rejected is generally high in ash and inerts content and, therefore, the resulting RDF is low in ash content. As the RDF processing system is designed to obtain a higher yield, more of the ash is carried over into the RDF fuel fraction and the ash content is increased.

The RDF heating value is inversely related to the yield; the higher the yield, the lower the heating value. In a high yield system, most of the rejects are ferrous metals and inerts (glass, ceramics, dirt) which have no heating value. While some fuel is also rejected, the quantity is small resulting in a higher net heating value for the RDF. A yield of about 93% represents a crunch and burn type system in which only the ferrous metal is removed. In such a system, the RDF heating value is only marginally higher than the heating value of the incoming MSW.

A typical MSW might have a composition comparable to the reference waste shown in Table 4. The majority of the waste is combustible materials, which have ash contents ranging from approximately 4% for wood to 12% for glossy magazine paper. The glass fraction, yard waste and mixed combustibles may also contain varying quantities of sand, grit and dirt. The predicted composition of the RDF will vary depending on the type of processing system and the resulting yield. Table 5 shows how the ash content in the fuel and the heating value of the fuel will vary as the RDF yield varies with different processing systems. Two cases are considered, one which assumes no front end recycling (curbside recycling or separate recycling facility), and a second case which assumes that such a system is in place in the community.

RDF quality

RDF used to supplement pulverized coal in utility boilers should be low in ash; have minimum ferrous metal, aluminum, and other nonferrous metal; and be small enough in particle size to be fed pneumatically to the boiler. The processing system for such a fuel would generally be a very low yield system, between 40 and 60%.

RDF for dedicated traveling grate stoker boilers should

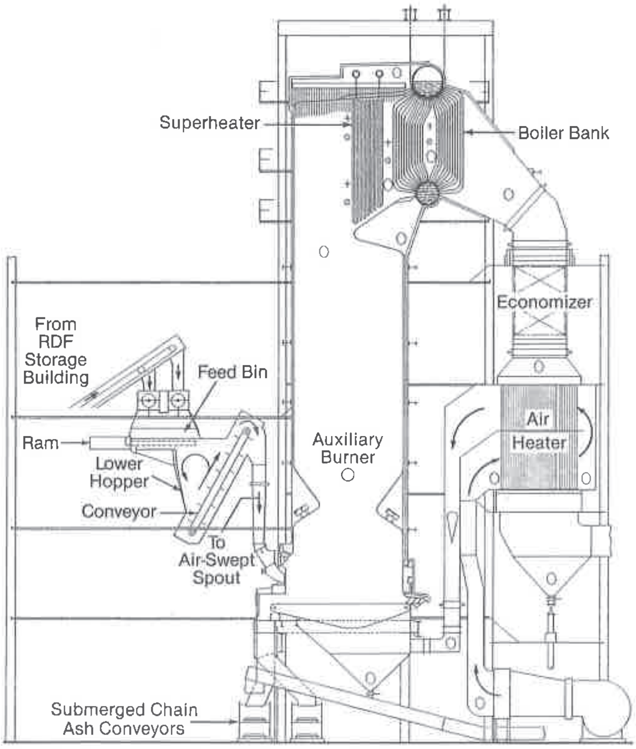


Fig. 19 Third generation RDF unit and fuel feeding system.

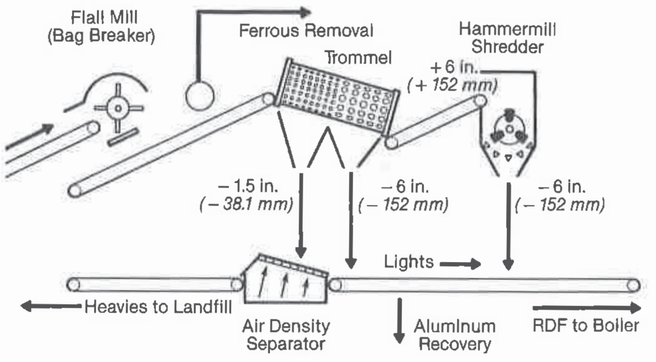


Fig. 20 RDF processing system.

be low in ash, consistent with a high RDF yield from the MSW; as free as possible of ferrous metal, aluminum and other nonferrous metals; and of a particle size distribution that is considerably larger than the particle size of RDF for use in Cyclone or pulverized coal boilers. The processing system for such a fuel will be a higher yield, around 70 to 85%.

RDF produced in a crunch and burn system, in which solid waste is shredded and only the ferrous metal removed, has a yield of about 93%; an inherently high ash content; and contains 100% of the aluminum, other non-ferrous metals, glass, stones and ceramics in the original MSW. While this is a high yield system which is desirable for a dedicated traveling grate stoker boiler, it also contains large quantities of aluminum, glass, and other inerts which results in higher wear on the stoker and lower furnace. Another result is a more conservatively designed stoker and furnace as well as a larger ash handling system.

RDF processing systems

An optimum RDF processing system for a dedicated boiler application achieves the highest yield with the highest heat recovery, while removing ferrous, aluminum and glass before entering the boiler. Such a system (Fig. 21) includes the following:

In-feed conveyors From the tipping floor, the solid waste is fed by front-end loaders to steel pan apron conveyors which feed the flail mill in-feed conveyors.

Initial size reduction The flail mill tears open the plastic garbage bags, coarsely shreds the refuse, and also breaks glass bottles to a size of approximately 1.5 in. (38.1 mm) or less.

Ferrous metal recovery Ferrous metal is extracted from the coarsely shredded MSW in each line by a single-stage overhead magnet. Recovered ferrous metal is moved to a ferrous air classifier where tramp materials such as paper, plastics or textiles are removed, thereby providing a clean ferrous product. A ferrous recovery of 90% is possible.

Size classification and final size reduction After ferrous removal, shredded waste is fed into a rotating trommel screen, a size separating device about 10 ft (3.0 m) in diameter by 60 ft (18.3 m) long. The trommel performs the following functions:

1. removes glass, sand, grit and nonferrous metal less than 1.5 in. (38.1 mm) in size, and
2. removes the minus 6 in. (152 mm), plus 1.5 in. (38.1 mm) fraction which is the proper fuel size without additional processing and contains the bulk of the aluminum cans.

The trommel oversize material, plus 6 in. (152 mm), is then shredded in a horizontal secondary shredder. Because the secondary shredder is a major consumer of energy and has high hammer maintenance costs, the RDF process is specifically designed to reduce the secondary shredder's load by shredding only those combustibles too large for the boiler. Particle size is controlled with a disk screen which recycles oversize material back to the secondary shredder.

Separation of glass, stones, grit and dirt Trommel undersize material, minus 1.5 in. (38.1 mm), passes over an air density separator (ADS) designed to remove dense particles from less dense materials through vibration and air sweeping. This device can efficiently remove glass, stones, grit and dirt, as well as nonferrous metals. The light fraction, which can range from approximately 50 to 90% of the ADS feed, consists essentially of combustibles with high fuel value which are recovered and blended into the main fuel stream.

Aluminum can recovery To optimize aluminum can recovery, an air classifier is provided for the plus 1.5 in. (38.1 mm), minus 6 in. (152 mm) undersize fraction. The air classifier removes the light organic portion of the stream, allowing aluminum cans to be more visible for hand pickers. The air classifier heavy fraction drops onto a conveyor moving at approximately 2.5 ft/s (0.76 m/s) with numerous hand-picking stations on either side of the belt. Cans

Table 4
Typical Reference Refuse

	Reference	
Component Analysis	MSW (% by wt)	RDF (% by wt)
Corrugated board	5.53	—
Newspapers	17.39	—
Magazines	3.49	—
Other paper	19.72	—
Plastics	7.34	—
Rubber, leather	1.97	—
Wood	0.84	—
Textiles	3.11	—
Yard waste	1.12	—
Food waste	3.76	—
Mixed combustibles	17.75	—
Ferrous	5.50	—
Aluminum	0.50	—
Other nonferrous	0.32	—
Glass	11.66	—
Total	100.00	
Ultimate Analysis		
Carbon	26.65	31.00
Hydrogen	3.61	4.17
Sulfur	0.17 (max. 0.30)	0.19 (max. 0.36)
Nitrogen	0.46	0.49
Oxygen	19.61	22.72
Chlorine	0.55 (max. 1.00)	0.66 (max. 1.20)
Water	25.30	27.14
Ash	23.65	13.63
Total	100.00	100.00
Heating value	4,720 Btu/lb (10,979 kJ/kg)	5,500 Btu/lb (12,793 kJ/kg)
Fuel value recovery, % MSW	96	
Mass yield, % RDF/MSW	83	

Table 5
RDF Yield versus Ash Content and Fuel Heating Value

Mode	RDF Yield %	Ash	Btu/lb (kJ/kg)
Without front-end recycling:			
Mass burn	100%	23.64	4,814 (11,197)
Crunch and burn	93%	19.87	5,146 (11,970)
RDF	83 to 70%	11.72 to 8.87	5,641 (13,121) to 5,834 (13,570)
With front-end recycling:			
Mass burn	100%	19.58	5,513 (12,823)
Crunch and burn	93%	17.16	5,898 (13,714)
RDF	85 to 71%	9.91 to 6.59	6,328 (14,719) to 6,491 (15,098)

go into hoppers and, by conveyor, to a can flattener. A pneumatic conveyor then transfers the flattened cans into a trailer. An eddy current separator, for the removal of aluminum cans, can replace hand picking if the expected amount of cans is high enough to justify the additional capital cost. Aluminum recovery of 60% is possible with hand picking or the eddy current separator.

Oversized bulky waste (OBW) The OBW shredder is generally a horizontal hammer mill used to shred ferrous metal recovered by the RDF processing lines and preseparated oversized material which includes white goods such as refrigerators and washing machines, furniture and tree limbs. The ferrous metal is magnetically recovered and given a final cleaning by an air scrubber to remove tramp materials. The nonferrous material is integrated into the RDF stream.

Tire shredding line If there is a sufficient supply of tires, a separate tire shredding line can be included. A shear shredder, used specifically for shredding tires, can shred 500 passenger car tires per hour. The shredder includes a rotary screen classifier (trommel) for returning shredded tire chips above 2 in. (51 mm) back to the shredder. A tire chip 2 x 2 in. (51 x 51 mm) or less is the final product which is then blended in with the RDF stream.

RDF storage building RDF from each processing line is conveyed to an RDF storage building. From there, it is either fed directly to the boiler or fed directly to a shuttle conveyor and storage pile. When RDF feed is direct to the boiler, excess RDF from the boiler feed system is returned to the RDF storage building. RDF not being fed directly to the boiler is retrieved from the storage pile by a front-end loader and loaded onto inclined conveyors which transport the RDF to the boiler feed system.

Fuel feed system: metering feeders

A successful RDF metering feeder must meet the following design criteria:

1. controlled metering of fuel to meet heat input demand,
2. homogenization of material to produce even density,
3. liberal access to deal with oversized material problems,
4. maintainability, in place, and
5. fire detection and suppression devices.

A reliable RDF metering feeder (see Fig. 19) is a key feature of the second generation RDF boiler design. One feeder is used for each air-swept fuel distributor spout. Each feeder has an upper feed bin which is kept full at all times by an over-running conveyor to ensure a continuous fuel supply. The fuel in this hopper is transferred to a lower hopper by a hydraulic ram. The ram feed from the upper hopper is controlled by level control switches in the lower hopper. The RDF is fluffed into a uniform density by a variable speed inclined pan conveyor which sets up a churning motion in the lower hopper. The pan conveyor delivers a constant volume of RDF per flight which is carried up the pan conveyor and deposited into the air-swept spout. The rate at which the fuel is deposited into the spout is based on fuel demand.

Air-swept distributor spouts

Air-swept fuel spouts, used extensively in the pulp and paper industry, proved to be equally effective for RDF firing. (See Chapter 26.) Lateral fuel distribution by multiple spouts across the width of the furnace delivers fuel evenly over the grate. Longitudinal distribution is accomplished by continuously varying the pressure of the air sweeping the spout floor. A major feature of this design is its simplicity.

Traveling grate stoker

To date, only traveling grates have been used for spreader-stoker firing of RDF. These grates move from the rear of the furnace to the front, into the direction of

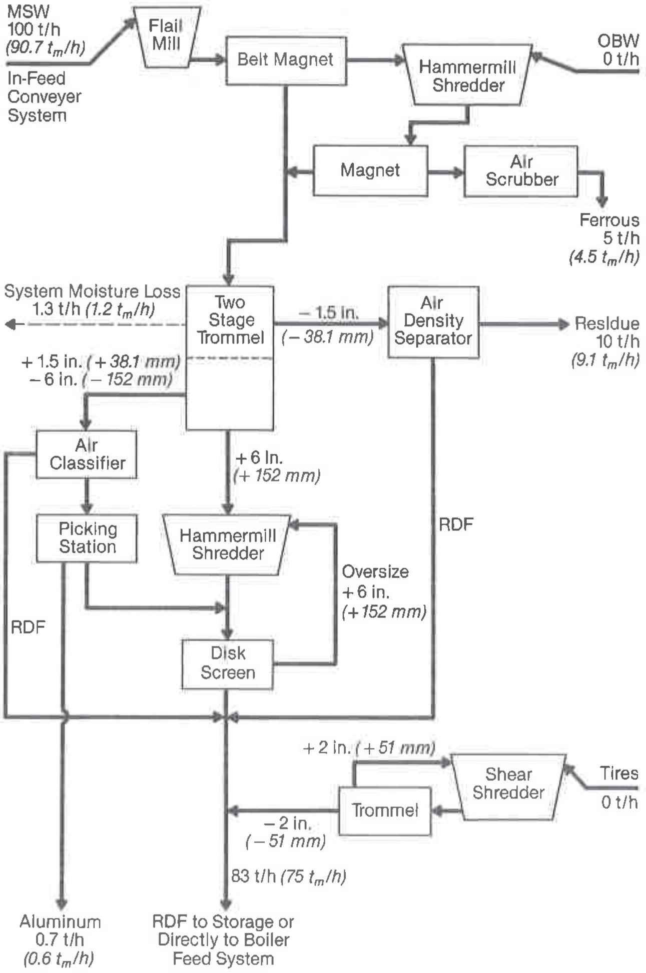


Fig. 21 Components of complete RDF processing system.

fuel distribution. A single undergrate air plenum is used. There is a wealth of experience worldwide with traveling grate stokers burning a myriad of waste and hard to burn fuels. The parameters for unit design shown in Table 6 were developed from this experience and the uniqueness of the RDF. (See also Chapter 15.)

On mass-fired stokers, a large volume of fuel at the front slowly burns down to a small volume of ash at the back. For an RDF stoker the key is to maintain an even 8 to 10 in. (203 to 254 mm) bed over the entire stoker area. Grate problems are usually due to a shallow ash bed. Operator tendency, when confronted with poor metering and/or fuel distribution, is to run the grates faster. While this technique can minimize bed upset, it will shorten grate life due to higher wear rates and the overheating of the grate bars. With the recommended ash bed thickness, tramp material is minimized, grate temperatures are lowered, wear is reduced and grate life is increased. To achieve this optimum ash bed requires controlled metering of the RDF and proper distribution of the fuel to the grates, as previously described.

A second problem is the accumulation of melted aluminum. The best solution is total removal of the aluminum from the fuel stream. If this is not practical, experience has shown that maintaining proper ash bed thickness will cause the aluminum to solidify in the ash bed rather than on the grate.

Fluidized-bed combustion, both circulating- and bubbling-bed designs, has been considered for RDF. For the high furnace pressure circulating beds, feeding the compressible RDF is a concern. For the bubbling beds, the feed system would be the same as for a stoker unit. In either case, RDF can be properly combusted. For coal firing, the inherent advantage of a fluid bed is the in-bed SO_2 capture. In-bed HCl capture, however, can not be achieved at the required removal efficiencies and therefore a back end scrubber is still required. A fluid bed boiler can achieve slightly lower NO_x emission levels and as emission requirements become more stringent, fluid bed combustion may become a viable alternative for the combustion of RDF.

Lower furnace design configuration

The lower furnace designs of early RDF boilers were largely based upon technology used for wood-fired boilers. This included modest overfire air (OFA) systems with multiple small diameter nozzles designed for 25 to 30% of the total air supply, straight wall furnaces and carbon re-injection systems. The result was less than desired combustion performance due to inadequate turbulent mixing in the furnace. Today's RDF units are designed with fewer, large diameter OFA nozzles designed for 50% of the total air supply with nominal operation at 40%.

In addition, B&W adapted its proven controlled combustion zone (CCZ™) lower furnace design for RDF firing. Developed originally in the early 1970s for very high moisture wood firing, this design consists of twin arches in the lower furnace with the overfire air nozzles directed down into the lower furnace from the arches (Fig. 22). The CCZ™ design for RDF applications without a carbon re-injection system has achieved lower unburned carbon loss than earlier designs which required the use of carbon re-injection systems.

The current B&W state-of-the-art RDF boiler system is exemplified by the Palm Beach County, Florida refuse facility which began operation in 1989. (See Fig. 23.) This design is currently used for all new B&W RDF boilers.

Table 6
Stoker Design Criteria (English units)

Parameters	RDF	Wood
Grate heat release, 10^6 Btu/h ft^2	0.750	1.100
Input per ft of grate width, 10^6 Btu/h	15.5	29
Fuel per in. of distributor width, lb/h	450	1,000
Feeding width as % of grate width	45 to 50	45 to 50
Grate speed, ft/h	25	N/A

Furnace exit gas temperature

Gas temperatures leaving the furnaces of first and second generation designs were higher than anticipated. There were not enough data on RDF firing to accurately predict the relationship between furnace surface area and furnace exit gas temperature. Compounding this problem was a continual increase in the heating value of the RDF due to changes in the composition of the raw refuse and the development of more efficient processing equipment. To achieve the desired furnace exit gas temperatures, the size of the third generation furnace has increased significantly. The furnace width and depth are set by the size of the stoker, therefore the furnace height has increased to achieve the required furnace exit gas temperatures.

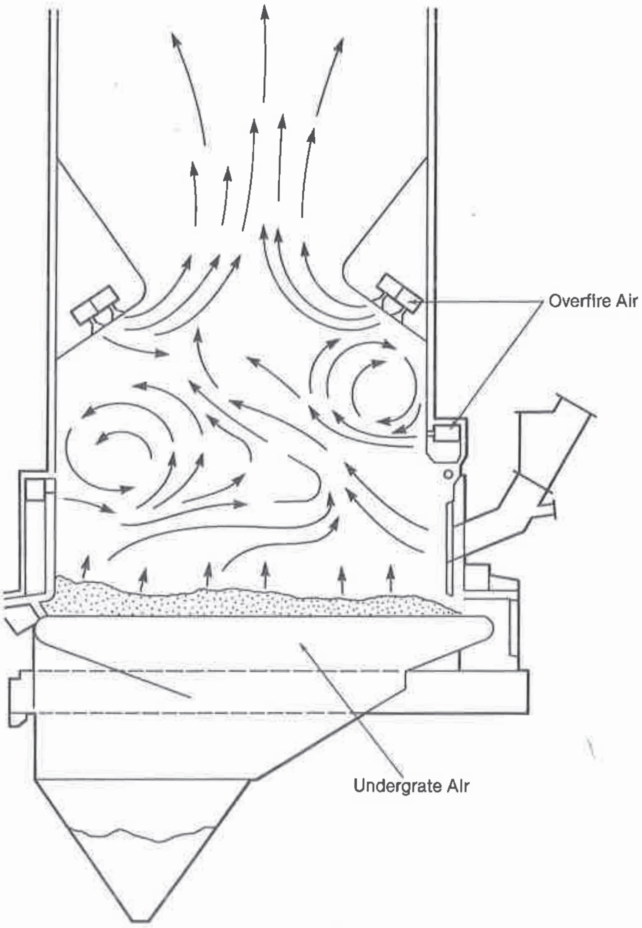


Fig. 22 Controlled combustion zone lower furnace.

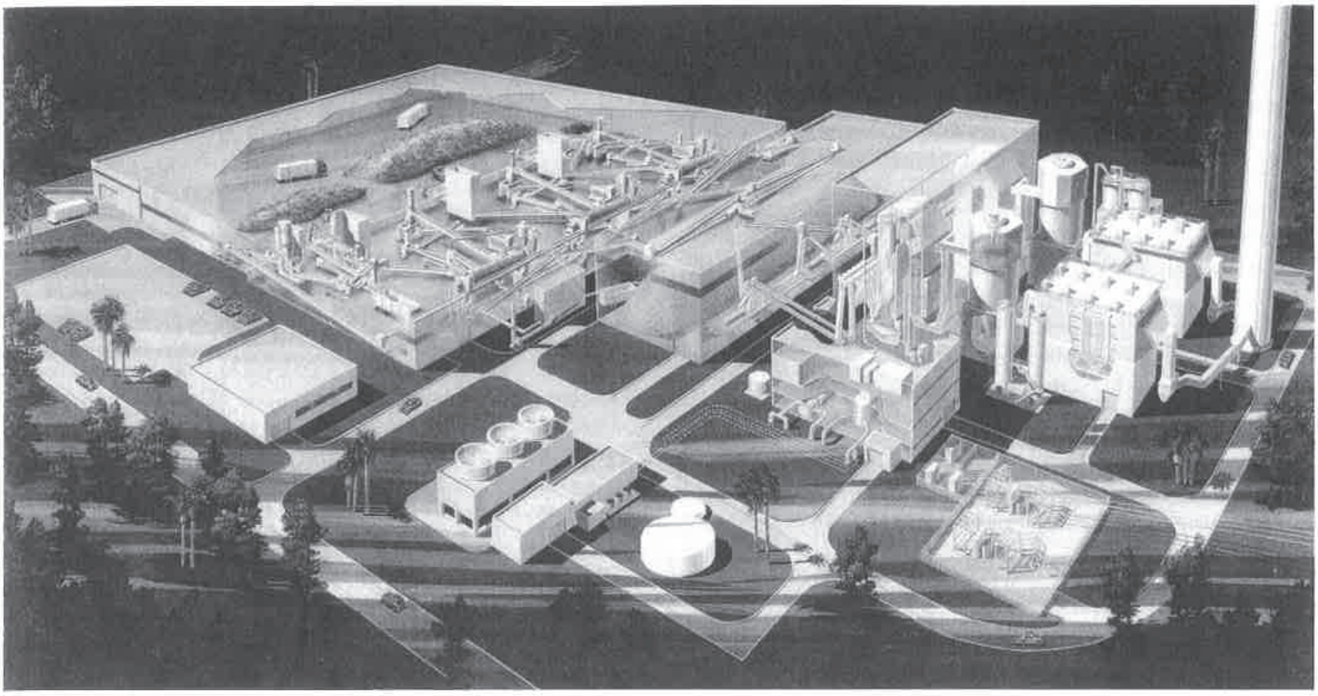


Fig. 23 West Palm Beach waste-to-energy facility.

Ash handling systems

Much of the noncombustible material in the RDF system is removed before it is fed to the boiler. Although systems vary, there is generally some effort made to remove ferrous metals and aluminum, both of which can be troublesome once they reach the stoker grates. Non-combustibles and most of the ash from combustion collect on the traveling grate stoker and discharge off the front into a submerged chain conveyor system.

The submerged chain conveyor (Fig. 24) is a mechanical conveyor that consists of a water filled trough and a dry return trough, with two endless chain strands with flights connected between the strands. The return trough can be either above or below the water filled trough. Ash from the stoker discharge chute drops into the water filled trough. The water absorbs the impact of any larger ash pieces, quenches the ash, and provides a gas-tight seal with the stoker discharge chute.

The chains are usually driven by a variable speed drive to handle varying ash rates. The ash residue is conveyed from the bottom of a water filled trough up an incline section where the ash dewaters and discharges directly into a truck, a storage bin, or onto another type conveyor for final disposal and transport. Because this conveyor uses a dragging action to convey the ash, it is not used on mass-fired units where it can have problems in dragging the large noncombustible items up the incline section.

Fine ash from the boiler siftings hopper, flyash from the boiler, economizer and air heater hoppers, and flyash from the scrubber, baghouse or precipitator hoppers are all handled the same way as previously discussed for mass-fired boilers.

Retrofits to RDF

Most dedicated RDF boilers are new installations. However, it is possible to retrofit existing boilers to become dedicated RDF boilers. To be candidates, the existing boilers must be conservative designs for solid fuels, such as wood or coal. Typically, these are older units which are underutilized or used as standby units. These plants are often located near large metropolitan areas, a source of large quantities of refuse. The conversion of such an older power plant could represent a cost effective solution to that community's refuse disposal problems.

B&W has converted several such boilers from coal-fired to dedicated RDF. Each retrofit is unique in that each of the coal-fired boilers was of different design and originally supplied by different manufacturers. Each retrofit was also the same in that all were designed to the same standards as new RDF units.

The principal modification involves enlarging the furnace to obtain the proper furnace volume for combustion. Although coal-fired boilers have conservatively sized furnaces, refuse firing requires even larger volumes. This is achieved by removing the existing stoker and lower furnace and installing new membrane furnace wall panel extensions (Fig. 25). The new lower furnace is protected from corrosion using either Inconel weld overlay or Inconel bimetallic tubes.

Other pressure part modifications could include:

1. converting the superheater to a counterflow design while adding the proper metals for corrosion protection,

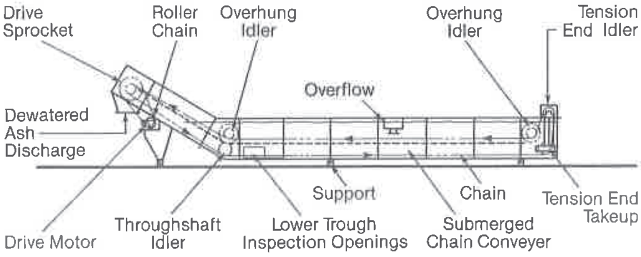


Fig. 24 Submerged chain conveyor for RDF stoker ash.

2. modifying the boiler, economizer and air heater surface for the proper heating surface distribution and to meet refuse standards for velocities, tube spacing, etc., and
3. possibly adding screen surface to lower the flue gas temperature entering the superheater.

In some cases, the coal stoker can be reused for RDF firing; in other cases it must be replaced. In either case the grate release rate, and other design criteria, must be set to the same design standards as new refuse boilers. Properly executed, the retrofit of an existing boiler to RDF firing will result in an RDF boiler as conservative as a new RDF boiler and capable of operating equally well.

Superheater

Superheater design is critical in both mass burn and RDF-fired refuse boilers because of the highly corrosive nature of the products of combustion. This is compounded in the U.S. by the desire for the highest possible steam temperature and pressure to maximize income from power production sales while still disposing of refuse in an environmentally safe manner. B&W has pioneered the 900 psig (62.1 bar gauge), 830F (443C) high pressure, high temperature steam cycle for refuse boiler application. This 50% increase in pressure and 80F (44C) increase in temperature over the more conventional refuse boiler designs has resulted in a significant improvement in cycle efficiency.

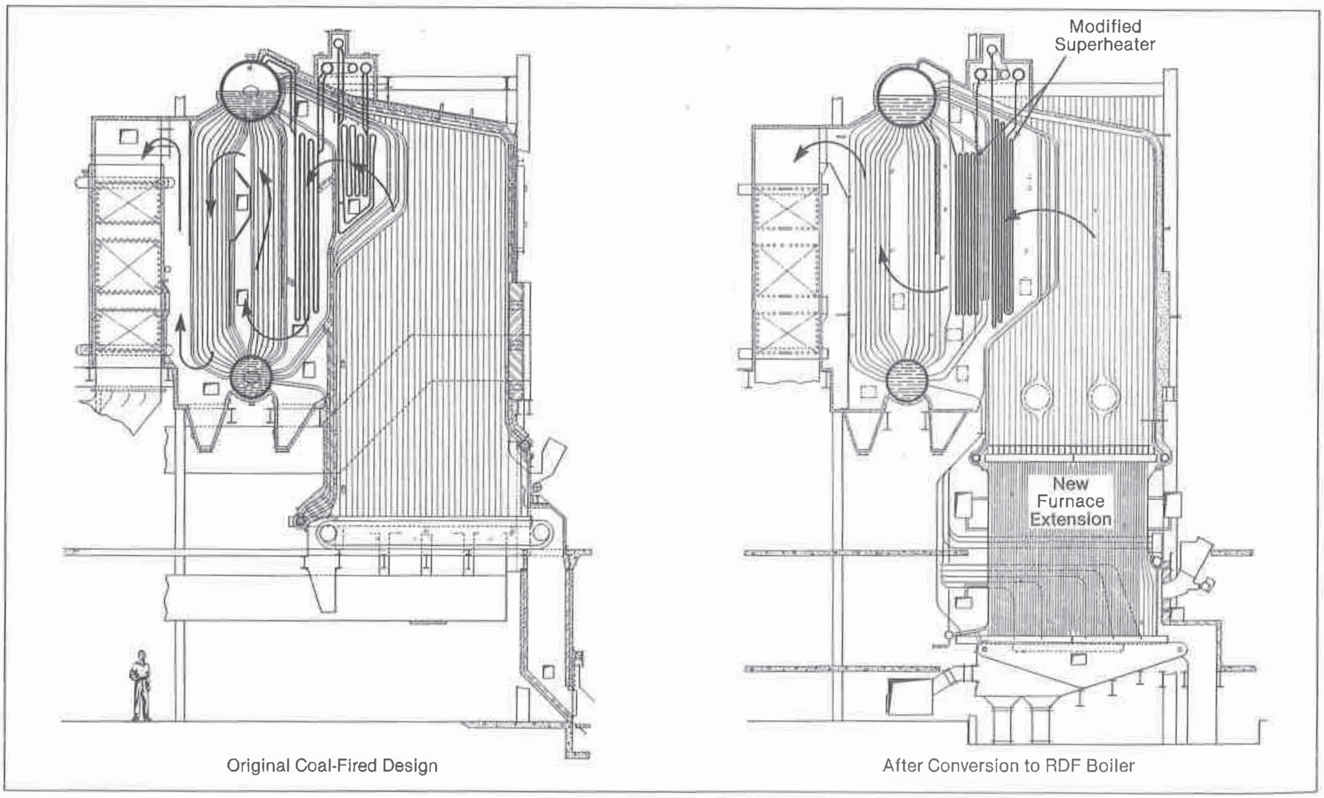
To accomplish this improvement, the superheater must be specifically designed for corrosion protection. Superheater corrosion is a function of many variables including flue gas temperature, flue gas velocity, tube spacing, tube metal temperature, tube metallurgy and ash cleaning equipment. Even a lower steam temperature superheater designed for one or a few of these criteria can experience rapid corrosion. For example, specifying only a low furnace exit gas temperature will not assure long superheater life.

Of these criteria, tube metal temperature and tube material are most critical. To obtain satisfactory refuse boiler superheater performance, two key design features are needed:

1. a parallel flow superheater design as shown in Fig. 26 where the coolest steam conditions are exposed to the hottest gas temperatures and the hottest steam temperatures are matched with the coolest gas temperatures. The result is a design with the lowest maximum superheater metal temperatures.
2. use of Incoloy tube material in the highest tube metal temperature sections of the superheater. Carbon steel is still used in the superheater sections with lower superheater metal temperatures.

B&W refuse boilers were the first to verify successful commercial operation at the 900 psig (62.1 bar gauge), 830F (443C) steam cycle with the first three units going into operation at the Westchester County, New York refuse-to-energy facility in 1984. As of 1992, there were 19 B&W refuse boilers in operation at these steam conditions with more than 75 cumulative years of operating experience. There has been no significant corrosion in any of these superheaters.

B&W is currently extending this leadership position with the first refuse boiler design to use the 1500 psig (103.4 bar gauge) and 930F (499C) steam cycle. This design is based on laboratory corrosion research and full scale superheater test sections installed in operating



Original Coal-Fired Design

After Conversion to RDF Boiler

Fig. 25 Coal-fired unit converted to RDF.

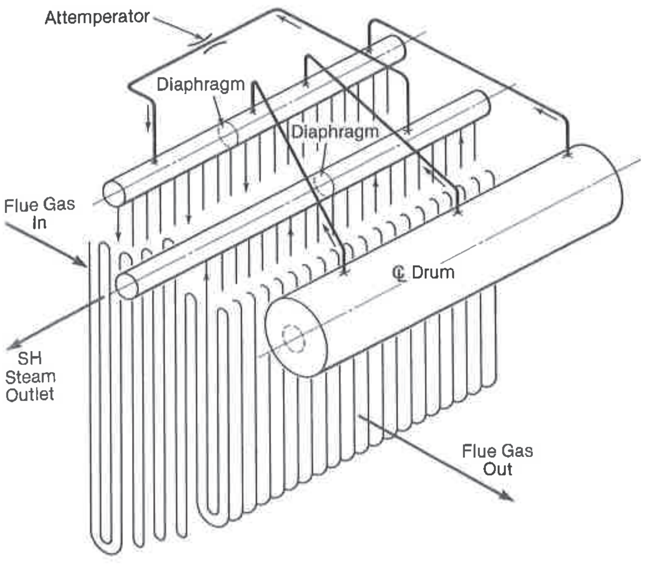


Fig. 26 Parallel flow superheater (SH).

refuse boilers. In one test, two full scale superheater sections, composed of a variety of tube metallurgies, were installed in an operating 900 psig (62.1 bar gauge), 830F (443C) design refuse boiler with steam flow through the sections controlled to simulate 950F (510C) operation. One section was removed after one year of operation and the second after 26 months. This test provided the basis for tube metallurgy selection for the 1500 psig (103.4 bar gauge), 930F (499C) design.

In addition to corrosion concerns, the superheater must be designed to minimize fouling and the potential for erosion due to excessively high flue gas velocities. Maximum design velocity is 30 ft/s (9.1 m/s), but in practice it is usually in the 10 to 15 ft/s (3 to 4.6 m/s) range. Minimum superheater side spacing is 6 in. (152 mm).

Boiler design

The lower furnace design, refuse stokers and refuse feed systems are markedly different for mass-fired and RDF boilers. However, the design requirements for the upper furnace, generating surface and economizer are the same. This is also true for auxiliary equipment such as burners and ash cleaning equipment.

Upper furnace design

The upper furnace must be sized to provide adequate heat transfer surface to reduce the flue gas temperature entering the superheater to an acceptable level. This helps minimize fouling in the superheater and maintain low superheater tube metal temperatures to minimize corrosion. A certain amount of furnace volume is required for complete burnout of the fuel in the furnace and minimum CO emissions. The required volume should be measured from the point where all the combustion air has entered the furnace (the highest level of overfire air ports) to the point where the flue gas enters the first convective heating surface (at the tip of the furnace arch at the bottom of the superheater). Measured in this manner, the required furnace volume per unit of heat input is the same for both mass-fired and RDF boilers.

The furnace must also contain sufficient heating surface to lower the flue gas temperature to help reduce fouling in the first convection section, superheater or boiler bank. These limits are 1600F (871C) entering the superheater and 1400F (760C) entering the boiler bank. As a general rule, the furnace size is set by volumetric requirements in smaller capacity boilers and by maximum gas temperature limits in larger capacity boilers.

Boiler generating bank

Refuse boilers in operation use both the one-drum and two-drum design. In the two-drum design there is both a steam drum (upper drum) and a lower drum, interconnected by the boiler generating bank tubes.

In the one-drum design the steam drum is located outside of the flue gas stream; there is no lower drum. The steam generating bank tubes are shop-assembled modules. These modules may be of either the vertical longflow (Fig. 27) or a vertical crossflow design. Minimum side spacing in the two-drum design and for the generating bank modules used with the one-drum design is 5 in. (127 mm). Maximum design flue gas velocity is set at 30 ft/s (9.1 m/s).

Economizer

The economizers can be either vertical longflow or horizontal crossflow. Economizer side spacing should be no less than 4 in. (102 mm) with a maximum flue gas velocity of 45 ft/s (13.7 m/s).

Air heater

Air heaters may be used for two reasons: 1) to supply preheated air to help dry and ignite the refuse on the stoker, and/or 2) to increase thermal efficiency where high feedwater temperatures preclude designing to lower exit gas temperatures with economizers. RDF-fired units have typically used air heaters to preheat the combustion air to the 300 to 350F (149 to 177C) range. Both tubular and regenerative air heaters have been used successfully. Due to air leakage into the air heater and the potential for fouling, regenerative types have been limited to the outlet side of hot electrostatic precipitators where the flue gases are relatively clean.

When either tubular or regenerative air heaters are used, the design and arrangement should minimize the potential for low-end temperature corrosion. To some extent, the surface arrangement in a tubular air heater will maintain adequate protection. Steam coil air heaters are required at the air inlet, on either type, to preheat the incoming ambient air and maintain temperature above acid dew points. (See also Chapter 19.)

Ash cleaning equipment

To maintain the effectiveness of all convective heating surfaces and to prevent pluggage of gas passages, it is necessary to remove ash and slag deposits from external tube surfaces. Steam or air sootblowers are most commonly used. Saturated steam is preferred for its higher density and better cleaning ability. One disadvantage of sootblowing is that localized erosion and corrosion can occur in areas swept too clean by the blowing medium. This problem can be addressed by installing tube shields on all tubes adjacent to each sootblower for localized protection.

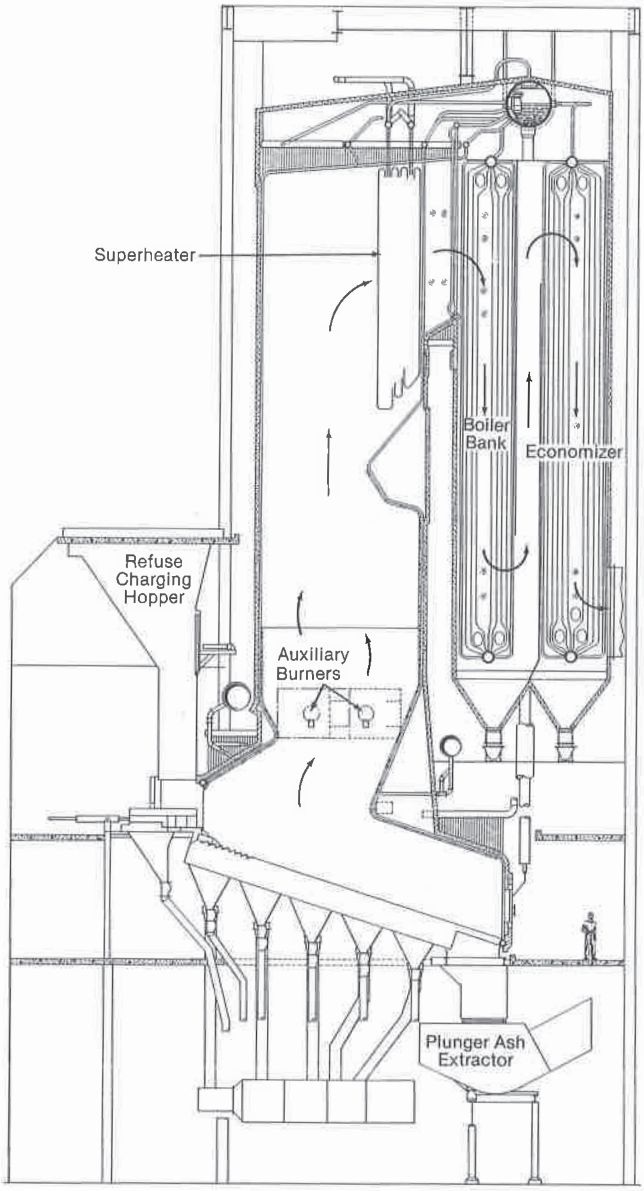


Fig. 27 Typical refuse unit with vertical longflow economizer.

A mechanical rapping system (Fig. 28) can be used to complement the sootblowers. In this system, a number of anvils strike designated pins to impart an acceleration through the superheater tube assembly. The purpose is to remove the bulk of the ash while leaving a light layer of ash on the tubes for corrosion protection. Mechanical rapping systems will not eliminate the need for sootblowers, but will reduce the number of sootblower cleaning cycles required.

Auxiliary input burners

Auxiliary fuel burners are used to maintain furnace temperature during startup, shutdown, and upset conditions since operation at low furnace temperatures could result in the incomplete destruction of volatile organic compounds. In most cases, the auxiliary fuel (oil or gas) burners are designed for only 25 to 30% of the boiler's maximum heat input.

When not in service, the typical gas- or oil-fired burner requires some amount of air flow through the idle burner for protection against overheating. Because this air leakage represents an efficiency loss, and because these burners are used infrequently, a special design auxiliary input burner (AIB) is used for refuse boilers. The AIB is designed with a retractable burner element which is inserted toward the furnace when in use, and retracted when out of service. There is also a movable refractory block which provides protection against furnace radiation when the burner is out of service. With the burner in service, this refractory block is retracted to one side and the burner is inserted through an opening in the refractory block (Fig. 29).

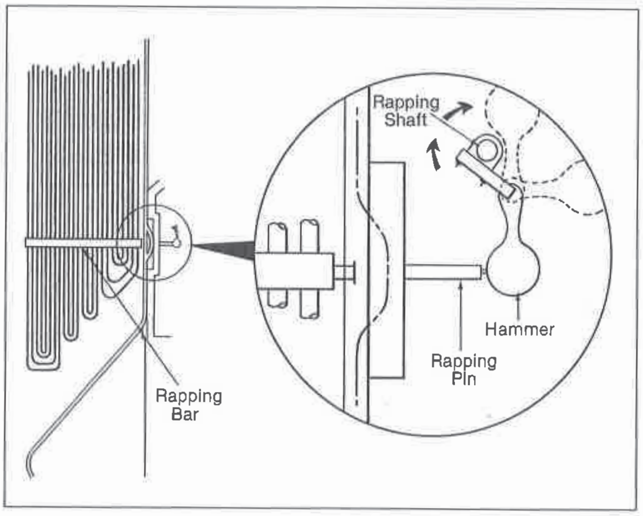


Fig. 28 B&W mechanical rapping system for cleaning superheaters.

Upper furnace maintenance platforms

Because refuse is a high fouling fuel, it is necessary to have good access to the convection sections. Maintenance platforms (Fig. 30) are often used to allow access to the superheater area for inspection and maintenance. Either retractable or light weight aluminum support beams are inserted into the furnace from access doors in the front wall to the superheater arch, where the beams are locked in place. Corrugated decking material is then inserted into the furnace through special sidewall access doors, and arranged on top of the support beams. This system provides both a platform for working in the superheater and upper furnace and provides some protection to those working in the lower furnace.

Air pollution control equipment

Various boiler fuels have specific components unique to that fuel. Some of these components, such as sulfur, create specific air pollution emissions that require unique boiler designs or specific air pollution control equipment. These fuels, such as high sulfur coal, are homogenous. This means the fuel will be the same in the future as it is today, and will be the same from one day to the next.

Refuse is a nonhomogenous fuel. It not only changes over the long term, but can change from day to day. Nearly every component of a fuel that can result in an unwanted air pollutant is present in refuse. However, in the early 1980s when the population of refuse-fired boil-

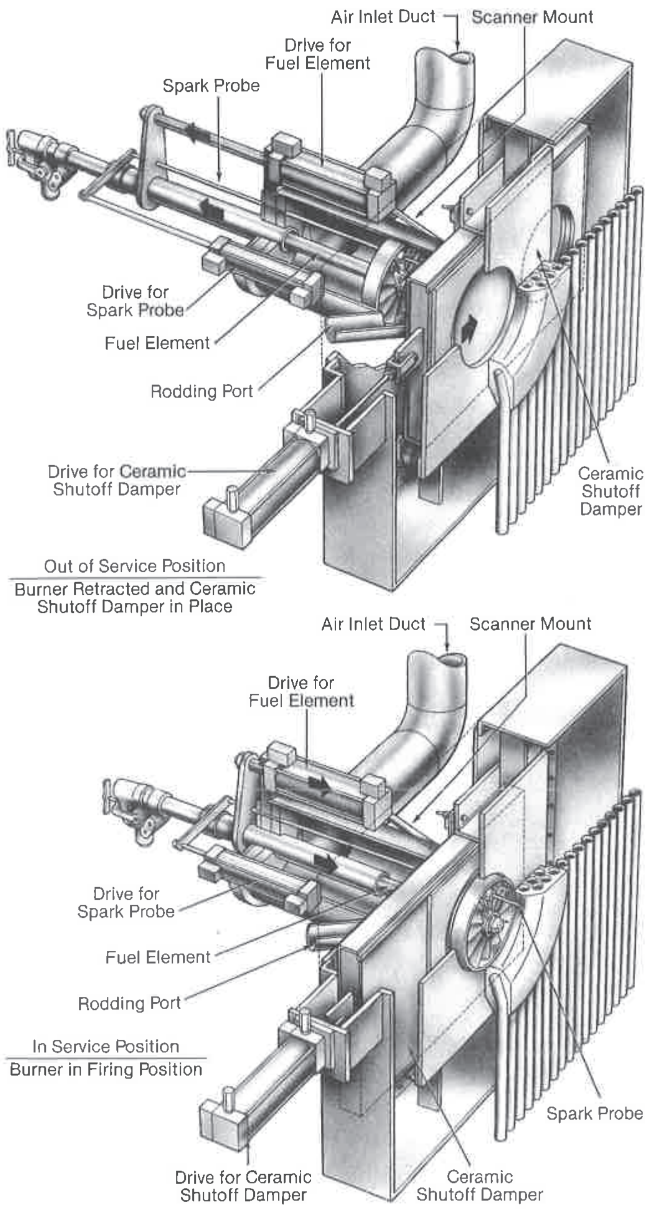


Fig. 29 Auxiliary input burner (out of service and in service positions).

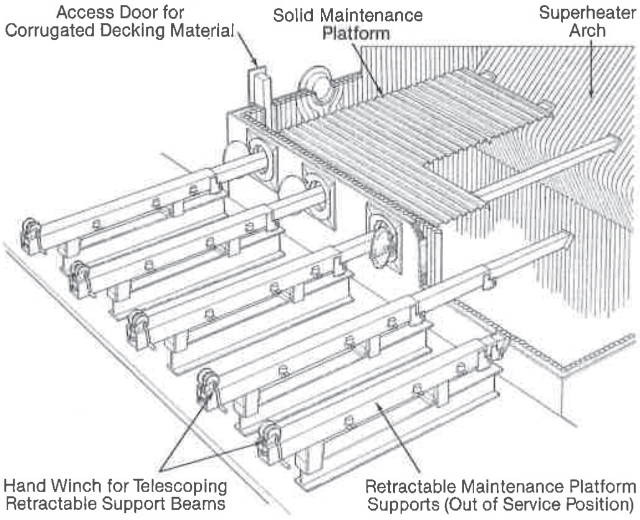


Fig. 30 Upper furnace maintenance platform.

Table 7
Permissible Stack Emissions (1990)

Pollutant	Emission Concentration
NO_x	200 to 350 ppmdv*
CO	20 to 100 ppmdv
VOC	< 10 ppmdv
SO_2	< 35 ppmdv**
HCl	< 20 ppmdv***
Particulate	< 0.01 gr/DSCF
PCDD/PCDF	< 10 ng/Nm^3****

Stack emission levels are test data values for units equipped with a dry scrubber and baghouse/precipitator, and may not represent values achievable in all normal daily operations. All stack emission concentrations are corrected to a 7% O_2 reference basis.

* NO_x emissions without add-on NO_x control technology.

** Typical SO_2 emissions with back-end control efficiency in the 70 to 90% range.

*** Typical HCl emissions with back-end control efficiency in the 90 to 98% range.

**** Total dioxin and furan emissions, including all tetra through octa homologies.

ers began to rapidly grow in the U.S., the only emission requirements were on particulates, NO_x and SO_2. Refuse boilers, due to their relatively cool burning systems and the generally low level of fuel bound nitrogen, are low NO_x generators. There are also very low levels of sulfur in refuse. Therefore, early boilers were generally equipped only with an electrostatic precipitator (ESP) for particulate control. As more boilers went into operation and further air emissions data were obtained, additional emission requirements were applied. Initially hydrochlorides were targeted for control. Soon the various state air pollution agencies set regulations for the control of dioxins and furans as well as a long list of heavy metals. Dry scrubbers, used for years to control SO_2 emissions from coal-fired units, were found to be equally effective in controlling HCl emissions from refuse units. These same dry scrubbers were also found to be very effective in controlling dioxin, furan and heavy metal emissions.

With the initial use of dry scrubbers, there was a split in the preferred particulate collection system between the ESP and baghouse. ESPs were used in earlier applications due to their more extensive history of proven performance. However, it has been fairly well documented that the layer of ash and lime that collects on the bags themselves allows improved sorbent utilization for the removal of SO_2 and HCl. This allows better capture of pollutants for the same lime slurry rates, or the same level of pollutant capture at slightly reduced lime slurry rates. Today, the preferred system for nearly all refuse boilers is the dry scrubber/baghouse combination.

In the late 1980s, lower level NO_x emissions were also being required. In-furnace ammonia or urea injection systems were installed on several refuse boilers and were shown to achieve NO_x reduction efficiencies in the 40% range. This NO_x control technology, termed selective noncatalytic reduction (SNCR), was quickly accepted by the regulatory agencies as best available control technology (BACT). In certain geographical areas, which are nonattainment areas for NO_x emissions, selective catalytic reduction (SCR) systems are also under evaluation for even greater NO_x control. The SCR systems have been demonstrated to achieve up to 90% NO_x reduction on fossil fuel boilers. However, the catalyst itself is fairly easily poisoned, and therefore rendered less effective, by a multitude of substances, all of which are found in refuse to various degrees. At this time it is not clear what the long term life of the SCR catalyst would be on a refuse-fired boiler. (See Chapters 32 through 35.)

During this same time period the emission requirements for CO have also been driven to lower levels. These requirements have been met by a combination of:

1. better overfire air system,
2. more control of undergrate air (more compartments with individual air control),
3. better combustion control systems,
4. larger furnace volumes, and
5. operator training.

The air emissions from refuse-fired boilers are as tightly regulated as those from any combustion system. However, the technology exists today to meet these requirements of the 1990s (Table 7) and will be available to meet future requirements.

Bibliography

Barna, J.L., Blue, J.D., and Daniel, P.L., "Furnace wall corrosion in refuse fired boilers," Proceedings of the ASME National Waste Processing Conference, Denver, Colorado, pp. 221-228, June 1-4, 1986.

Barsin, J.A., *et al.*, "Initial operating results of coal-fired steam generators converted to 100% refuse derived fuel," Proceedings of the American Power Conference, Chicago, April 18-20, 1988.

Barsin, J.A., "Initial operational results of a coal-fired steam generator converted to 100% RDF fuel," Proceedings of the ASME Joint Power Conference, Miami, Florida, October1987.

Bielawski, G.T., *et al.*, "Resource recovery in Palm Beach," Proceedings of the International Conference on Municipal Waste Combustion, Hollywood, Florida, April 11-14, 1989.

Blue, J.D., *et al.*, "Waste Fuels: Their Preparation, Handling and Firing," Section 3, Chapter 6, Standard Handbook of Powerplant Engineering, McGraw-Hill, pp. 3.117 to 3.151, February 1989.

Blue, J.D., Gibbs, D.R., and Hepp, M.P., "Design and operating experience with high temperature and high pressure refuse-fired boilers," Proceedings of the ASME National Waste Processing Conference, Philadelphia, pp. 93-99, May 1-4, 1988.

Blue, J.D., and Strempek, J.R., "Considerations for the design of refuse-fired water wall incinerators," Proceedings of the Conference on Energy From Municipal Waste, Washington, D.C., October 24-25, 1985.

Boman, E., *et al.*, "The greater Bridgeport regional resource recovery project: A waste-to-energy reincarnation," Proceedings of the ASME National Waste Processing Conference, Long Beach, California, pp. 345-351, June 3-6, 1990.

Burnham, D.E., *et al.*, "The evolution of RDF boiler designs through state-of-the art system at Palm Beach," Proceedings of the EPRI 1989 Conference on Municipal Solid Waste as a Utility Fuel, Springfield, Massachusetts, pp. 3-45 to 3-61, October 10-12, 1989.

Campobenedetto, E.J., *et al.*, "City of Lakeland to generate power and burn municipal waste," Proceedings of The American Power Conference, Chicago, April 26-28, 1982.

Chambliss, C.W., Hestle, J.T., and McNertney, R.M., "Operating experience is reflected in Nashville's new refuse boiler," Proceedings of the Joint ASME/IEEE Power Generation Conference, Portland, Oregon, October 20-23, 1986.

Clunie, J.F., *et al.*, "The importance of proper loading of refuse fired boilers," Proceedings of the ASME National Waste Processing Conference, Orlando, Florida, pp. 169 - 177, June 3-6, 1984.

Cramblitte, D.I., *et al.*, "Akron recycle system is on-line," Proceedings of The ASME Waste Processing Conference, Washington, D.C., pp. 463 - 474, May 11-14, 1980.

Gibbs, D.R., and Kreidler, L.A., "From Hamilton to Palm Beach: The evolution of dedicated RDF plants," Proceedings of the Processed Fuels and Material Recovery from Municipal Solid Waste Symposium, Washington, D.C., Section 7, December 1-2, 1986.

Gibbs, D.R,. and Kreidler, L.A., "What RDF has evolved into," pp. 251-262, *Waste Age*, April 1989.

Gibbs, D.R., and Hepp, M.P., "Mass-burn plant achieves high availability, Low Emissions," *Power*, April 1990.

Gibbs, D.R., "Refuse to energy," pp. 14, 15 and 32, *Pennsylvanian*, June 1990.

Gibbs, D.R., "Examine utility options in refuse-to-energy business," pp. 53-55, *Electrical World*, August 1990.

Hanson, W.C., and Scheatzle, J.E., "The design and start-up of the Elk River's conversion to RDF firing," Proceedings of the 1989 EPRI Conference on Municipal Solid Waste as a Utility Fuel, Springfield, Massachusetts, pp. 3.3 to 3.12, October 10-12, 1989.

Hepp, M.P., Nethercutt, R.M., and Wood, J.F., "Considerations in the design of high temperature and pressure refuse fired power boilers," Proceedings of the ASME National Waste Processing Conference, Denver, Colorado, pp. 113-118, June 1-4, 1986.

Herrmann, R.H., "Improvements in the quality of RDF," Proceedings of the EPRI 1989 Conference on Municipal Solid Waste as a Utility Fuel, Springfield, Massachusetts, pp. 3-13 to 3-24, October 10-12, 1989.

Herrmann, R.H., "Palm Beach County waste processing facility," Proceedings of the GRCDA Resource Recovery Symposium '90, West Palm Beach, Florida, January 16-18, 1990.

Herrmann, R.H., "RDF-fired systems," Proceedings of Waste-To-Energy '87: Exploring the Total Market, Washington, D.C., September 21-22, 1987.

Jackson, B.W., Scheatzle, J.E., and Taylor, D.A., "Design to convert a three boiler power plant to RDF firing," Proceedings of the Industrial Power Conference, Houston, Texas, October 1988.

Johnson, N.H., and Reschly, D.C., "MSW and RDF: An examination of the combustion process," Proceedings of the ASME Joint ASME/IEEE Power Generation Conference, Portland, Oregon, October 20-23, 1986.

Larsen, P.S., "Continuously monitoring furnace temperature in refuse boilers using acoustic pyrometry," Proceedings of the Waste Technology 1986 Conference, Chicago, October 20-22, 1986.

Rochford, R.S., and Witkowski, S.J., "Considerations in the design of a shredded municipal refuse burning and heat recovery system," Proceedings of the ASME Waste Processing Conference, Chicago, May 7-10, 1978.

Schueler, P.H., "The case for dedicated refuse conversion of utility boilers," Proceedings of the Power-Gen '88 Conference, Orlando, Florida, December 6-8, 1988.

Strach, L., "Operating experience of refractory linings in mass-refuse fired waterwall boilers," Proceedings of the ASME National Waste Processing Conference, Philadelphia, pp. 1-8, May 1-4, 1988.

Scavuzzo, S.A., Strempek, J.R., and Strach, L., "The determination of the thermal operating characteristics in the furnace of a refuse-fired power boiler," Proceedings of the ASME Waste Processing Conference, Long Beach, California, pp. 397-404, June 3-6, 1990.

Chapter 32
Environmental Considerations

Since the early 1960s, there has been an increasing worldwide awareness that industrial growth and energy production from fossil fuels are accompanied by the release of potentially harmful pollutants into the environment. Studies to characterize emissions, sources and effects of various pollutants on human health and the environment have led to increasingly stringent legislation to control air emissions, waterway discharges and solids disposal.

Comparable concern for environmental quality has been manifest worldwide. Since the 1970s, countries of the Organization for Economic Cooperation and Development have reduced sulfur dioxide (SO_2) and nitrogen oxides (NO_x) emissions from power plants in relation to energy consumption. In at least the foreseeable future, emission trends are expected to continue downward due to a combination of factors: change in fuel mix to less polluting fuels, use of advanced technologies, and new and more strict regulations. In Japan, the reductions in SO_2 emissions were particularly pronounced due to strong environmental measures taken in the 1970s. In the United States (U.S.), use of flue gas desulfurization systems and low sulfur coal have resulted in an approximate 30% decrease in utility SO_2 emissions between 1970 and 1989, while electricity produced from coal increased approximately 120%.

Environmental control is primarily driven by government legislation and the resulting regulations at the local, national and international levels. These have evolved out of a public consensus that the real costs of environmental protection are worth the tangible and intangible benefits now and in the future. To address this growing awareness, the design philosophy of energy conversion systems such as steam generators has evolved from providing the lowest cost energy into providing low cost energy with an acceptable impact on the environment. Air pollution control with emphasis on particulate, NO_x and SO_2 emissions is perhaps the most significant environmental concern for fired systems and is the subject of Chapters 33, 34 and 35, respectively. However, minimizing aqueous discharges and safely disposing of solid byproducts are also key issues for modern power systems.

Sources of plant emissions and discharges

Fig. 1 identifies most of the significant waste streams from a modern coal-fired power plant. Typical discharge rates for the primary emissions from a new 500 MW coal-fired drum boiler, with and without control equipment, are summarized in Table 1.

Atmospheric emissions arise primarily from the byproducts of the combustion process [SO_2, NO_x, particulate flyash, volatile organic compounds (VOC) and some trace quantities of other materials] and are exhausted from the stack. A second source of particulate is fugitive dust from coal piles and related fuel handling equipment. This is especially significant for highly dusting Western U.S. subbituminous coals. Some low temperature devolatilization of the coal can also emit other organic compounds. A final source of air emissions is the cooling tower and the associated thermal rise plume which contains heat and some trace materials along with the water vapor.

Solid wastes arise primarily from collection of the coal ash from the bottom of the boiler, economizer and air heater hoppers, as well as from the electrostatic precipitators and fabric filters. Pyrite collected in the pulverizers (see Chapter 12) is usually also included. Most of the ash is transported to an ash settling pond where it settles out and is prepared for either landfill or other use. The chemical composition and characteristics of various ashes are discussed in Chapter 20.

The second major source of solids is the byproduct from the flue gas desulfurization (FGD) scrubbing process. Most frequently, this is a mixture containing calcium sulfate or calcium sulfite. After dewatering, processing and treatment, the byproduct may be sold as gypsum or landfilled. Additional sources of solids include the sludge from cooling tower basins, wastes from the water treatment system and wastes from the periodic boiler chemical cleaning.

Aqueous discharges arise from a number of sources. These include once-through cooling water (if used), cooling tower blowdown (if used), sluice water from the ash handling system (via the settling pond), FGD waste water (frequently minimal), coal pile runoff from rainfall, boiler chemical cleaning solutions, gas side water washing waste solutions, as well as a variety of low volume wastes including ion exchange regeneration solutions, evaporator blowdown (if used), boiler blowdown and power plant floor drains. Many of these streams are chemically characterized in Chapter 42. Additional discussions of these systems as well as the controlling regulations are provided in References 1 and 2.

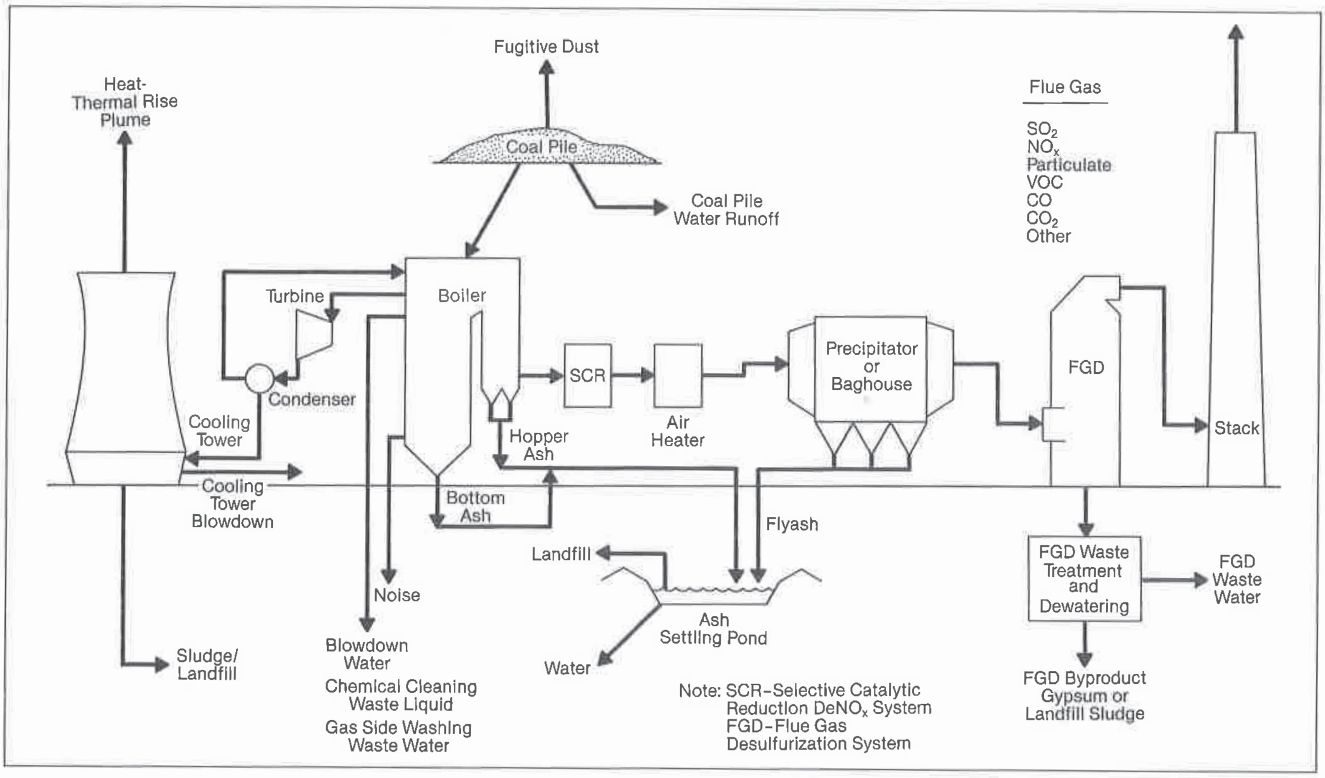


Fig. 1 Typical power plant effluents and emissions.

Air pollution control

U.S. legislation — Clean Air Act

The 1990 Amendments to the Clean Air Act (CAA), signed into law on November 15, 1990, have significantly expanded the original Act. The Amendments represent a significant increase in the U.S. commitment to an improvement in environmental quality. These Amendments build on the framework of the CAA which was originally enacted in 1963 and periodically amended since that time.

The Clean Air Act serves as the national basis for maintaining and improving the air quality through a series of minimum national requirements in a number of areas. The primary objective of the Act is *to protect and enhance the quality of the nation's air resources so as to promote the public health and welfare and the productive capacity of its population.*[3] The legislation generally provides for the U.S. Environmental Protection Agency (EPA) to set the minimum national requirements and to provide regulations, guidelines and guidance to the state and local regulatory agencies for implementation. The state and local government agencies are responsible to develop and implement plans to at least meet the federal requirements. However, they may also adopt more stringent regulations. The Act as amended prior to 1990 addressed the following areas of potential interest to boiler operators.

National Ambient Air Quality Standards These define acceptable air quality levels to protect public health and thereby set objectives for improvement. National Ambient Air Quality Standards have been defined for the six *Criteria Pollutants*: sulfur dioxide (SO_2), nitrogen dioxide (NO_2), carbon monoxide (CO), ozone (O_3), particulate matter and lead.

Table 1
Typical 500 MW Coal-Fired Steam Generator Emissions and Byproducts
[2.5% sulfur, 16% ash, 12,360 Btu/lb (28,749 kJ/kg)]

Emission	Typical Control Equipment	Discharge Rate — t/h (t_m/h) Uncontrolled		Controlled	
SO_x as SO_2	Wet limestone scrubber	9.3	(8.4)	0.9	(0.8)
NO_x as NO_2	Low NO_x burners	2.9	(2.6)	0.7	(0.7)
CO_2	Not applicable	485	(440)	485	(440)
Flyash to air*	Electrostatic precipitator or baghouse	22.9	(20.8)	0.05	(0.04)
Water stream thermal discharge	Natural draft cooling tower	2.8 x 10^9 Btu/h	(821 MW_t)	~0	
Ash to landfill*	Controlled landfill	9.1	(8.3)	32	(29)
Scrubber sludge: gypsum plus water	Controlled landfill or wallboard quality gypsum	0		25	(27.7)

* As flyash emissions to the air decline, ash shipped to landfills increases.

State Implementation Plans (SIP) These plans are submitted by states to identify how the national standards will be implemented. They divide each state into a number of identifiable areas known as air quality control regions, in which at least the minimum National Ambient Air Quality Standards must be met and control requirements imposed as needed to achieve compliance.

New Source Performance Standards (NSPS) For more than 60 types of new and modified sources, these provide that best demonstrated available control technology must be used to satisfy requirements as set forth in Section III, Title 40 of the U.S. Code of Federal Regulations (CFR).[4]

Air toxics The Act authorized the setting of standards to limit human exposure to air toxics, which include any potentially hazardous non-criteria air pollutants. The standards are risk based and require an ample margin of safety to prevent any adverse effects (essentially zero risk).

New source review This activity is intended to prevent significant environmental deterioration from industrial growth in the form of new plants or expansion of existing plants.

Enforcement The Act provides the EPA and state agencies with the authority to bring civil and criminal actions against violators of the statutes.

Evolution of U.S. clean air legislation and key elements

The Clean Air Act has evolved from the first legislation passed in 1963 to establish authority for setting air quality standards through the Clean Air Act of 1970, which was more comprehensive and provided greater statutory strength for implementing regulatory efforts in the 1970s and 1980s. During the Middle East Oil Embargo of October 1973, the U.S. Congress, in an attempt to ensure an adequate energy supply, modified some air quality requirements through the Energy Supply and Environmental Coordination Act. In 1977 the Clean Air Act was revised to address prevention of significant deterioration of the environment and defined requirements for new sources in areas where National Ambient Air Quality Standards had not been attained.

Elements of the pre-1990 Amendments which have had the most impact on utility and industrial boilers include National Ambient Air Quality Standards and the New Source Performance Standards. National Ambient Air Quality Standards promulgated by the EPA established minimum numerical criteria for the country. Two types of standards have been established, primary standards aimed at prevention of adverse impact on human health and secondary standards to prevent damage to the environment. While ambient air quality standards have been set for the six Criteria Pollutants [CO, SO_2, NO_2, ozone (O_3), particulates and lead], there has been intense controversy in establishing what constitutes safe concentrations, accounting for the combined effects of exposure to multiple pollutants and the limited number of pollutants covered.

Before the 1977 CAA Amendments, FGD systems installed on utility boilers were designed to limit SO_2 emissions to not more than 1.2 lb per million Btu heat input. Burning low sulfur coal with less than 0.7% sulfur required no scrubbing. Coal with 3% sulfur required only 75 to 80% SO_2 removal efficiency.

The Amendments of 1977 required new utility power stations to reduce SO_2 emissions by 90% for high sulfur coals, by 70% for low sulfur coals and by a sliding scale for intermediate sulfur coals. (See Fig. 2.) A key element of the legislation and prior amendments was that a large population of existing operating utility boilers was not required to lower emissions, i.e., grandfathered, unless they were significantly modified or upgraded.

The Amendments of 1990 enhanced the previous legislation in a number of areas which have an impact on both existing and new fossil fuel-fired utility generation capacity.

Nonattainment areas (those areas not achieving National Ambient Air Quality Standards) were given new classifications and deadlines to achieve attainment under Title I of the Act. These deadlines were set on the basis of present pollution levels. This portion of the legislation may have a dramatic but indirect impact on boiler system NO_x emissions in selected nonattainment areas because NO_x is one precursor to ozone formation.

Air toxics were defined in Title III to include a list of 190 hazardous air pollutants, and the EPA was directed to promulgate control standards for sources of these emissions. While air toxics were addressed in the Act of 1970, standards had only been promulgated for seven substances by 1990. The EPA has been directed to impose tight controls through a two-phase strategy. The first phase is technology based and would require application of Maximum Achievable Control Technology (MACT) to selected categories of emission sources which emit more than minimum or threshold quantities of the listed pollutants. The second phase is risk based and may require certain facilities to apply additional controls beyond MACT to reduce remaining residual risk. Utility boilers are initially exempted from this section until the EPA studies the emissions of the air toxics from utility plants and their impact.

Acid rain (discussed below) was addressed under Title IV of the 1990 Amendments in the form of new requirements applying mainly to coal-fired power plants.

Title IV, Acid Deposition Control The 1990 Amendments establish a new market based control methodology which focuses on the control of SO_2 and NO_x emissions from fossil-fired power plants. Annual U.S. emissions of SO_2 are to be reduced by 10 million tons and annual U.S. emissions of NO_x as NO_2 are to be reduced by 2 million tons by the year 2000. This reduction is planned to take place in two phases, with the first beginning in 1995. The market based system requires utilities to use an Allowance (a permit to

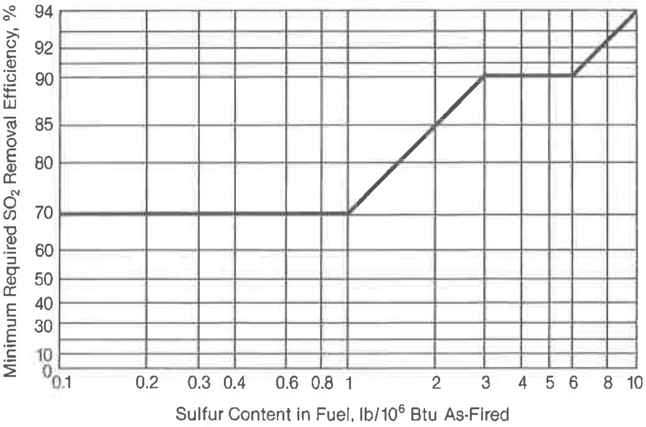


Fig. 2 Effective New Source Performance Standards for coal-fired utility boilers prior to November 15, 1990.

emit one ton of SO_2 on or after a certain year) for each ton of SO_2 emitted after a certain date. Each existing utility boiler site receives a certain number of Allowances per year. The plant owner then has the option to either: 1) reduce emissions through fuel switching, the application of control technology or other options, or 2) acquire additional Allowances from other plants to cover the actual SO_2 emissions. Any unused Allowances may be sold or kept (*banked*) for future use. The total number of new Allowances issued each year is fixed and new power plants will not receive an Allowance allocation. This effectively caps total utility SO_2 emissions.

The NO_x control section of the acid rain legislation is part of the more traditional command and control approach where specific units or types of equipment will be allowed only certain levels of NO_x emission rates based upon fuel heat input (pounds of NO_x as NO_2 per million Btu input) although averaging will be permitted between plants.

As in prior environmental legislation, local or state environmental regulatory agencies may impose stricter regulations on individual plants, areas or locations.

New Source Performance Standards These regulations establish maximum emission rates for selected pollutants from new boilers. The NSPS were conceived to be a technology — forcing approach to provide an incentive to develop new control technology. Again, these were national maximum limits which could be tightened by the local or state implementing agencies. An example of NSPS requirements for utility boilers with a capacity greater than 250 x 10^6 Btu/h firing coal, oil or gas is provided in Table 2. Fig. 2 provides an overview of the SO_2 reduction and control requirements for coal-fired units. The details for specific applications and other fuels and technologies may be found in Title 40, Part 60, Subparts Ca, D, Da, Db, Dc, E, Ea and BB of the Code of Federal Regulations.[4] The 1990 Amendments to the Act direct the EPA to revise the NSPS.

In December 1987, the EPA issued similar guidelines for smaller industrial units which were updated in December 1989. Selected elements of these rules are summarized in Table 3. Refer to Title 40, Part 60, Subpart Db of the CFR for site specific details and rules.[4]

The NSPS apply not only to new boilers but also to boilers which undergo substantial modifications. However, the extent of the modifications and the change in pollutant emissions which trigger NSPS are currently under review.

Prevention of significant deterioration PSD relates to avoiding a reduction in air quality from industrial growth in areas that already meet air quality standards. In these PSD areas, new major sources and major modifications to existing sources are required to use Best Available Control Technology (BACT). Air quality analyses are also performed to show that the air quality standards will not be exceeded.

Nonattainment Areas that do not meet the air quality standards for a given pollutant are referred to as nonattainment areas for that pollutant. Different rules apply for new sources in these areas. New sources must apply state-of-the-art (SOA) technology and must offset the remaining emissions after application of SOA technology by reducing emissions in existing sources.

In applying the SOA technology, the Lowest Achievable Emission Rate (LAER) is to be attained. This means that the emission rate must meet the most stringent limit in any SIP or the most stringent limitation achieved by plants in the same industrial category, whichever is more stringent.

Table 2
Selected Summary of Federal NSPS for Electric Utility Steam Generators >250 million Btu/h Commencing Construction After September 18, 1978 (Notes 1 and 2)

Fuel	Pollutant	Max. Emissions Rate (lb/10^6 Btu) (Notes 3 and 6)	Req'd. Reduction in Potenial Emissions, % (Note 3)
Coal	SO_2	1.2 or 0.6	90 or 70
	NO_x as NO_2:		
	Subbituminous	0.5	(Note 4)
	Bituminous	0.6	
	Particulate	0.03 (Note 5)	99
Oil	SO_2	0.8 or 0.2	90 or 0
	NO_x as NO_2	0.3	(Note 4)
	Particulate	0.03 (Note 5)	70
Gas	SO_2	0.8 or 0.2	90 or 0
	NO_x as NO_2	0.2	(Note 4)
	Particulate	0.03 (Note 5)	—

Notes:
1. Source: 40CFR60 Subpart Da (6/11/79).
2. For reference only: see source for details.
3. *Maximum Emissions Rate* and *Req'd. Reduction in Potential Emissions* must both be met.
4. Selected % reductions are also identified for NO_x but meeting the Maximum Emissions Rate stated constitutes compliance with the % reduction requirements.
5. Separate opacity limit of 20% may be controlling.
6. Approximate SI conversions:[5] mg/Nm^3 per lb/10^6 Btu = 1230 for coal at 6% O_2, 1540 for oil at 3% O_2 and 1590 for gas at 3% O_2.

Best Available Control Technology Classification of a control technology as BACT is determined on a case by case basis by the EPA. It is then up to the owner of the new plant or plant expansion to justify deviations from BACT based on its inapplicability to the proposed plant.

Increments of air quality In addition to the application of BACT, the resulting emissions from the source must meet the available increment of air quality. All areas in the U.S. which meet the National Ambient Air Quality Standards are divided into Class I areas (that are to be kept in a pristine condition) and Class II areas (where industrial growth will be allowed). For each class an allowable degradation increment is determined. The air quality increment for a given area is set so that the resulting air quality after degradation from a new source is cleaner than what is required to satisfy the ambient air quality standard. As might be expected, Class I areas allow almost no degradation. Air quality increments have been set for SO_2, NO_x and particulates.

International regulations — air pollution control

The passage of the Clean Air Act in the U.S. in 1963 marked the first enactment of air pollution control legislation by a major industrial nation. Since that time, air pollution control regulations have become more widespread in industrial and developing nations, particularly in Ja-

Table 3
Selected Summary of Federal NSPS for Industrial Steam Generators >100 million Btu/h Commencing Construction, Modification or Reconstruction After June 19, 1984
(Notes 1 and 2)

Fuel	Pollutant: Technology	Max. Emissions Rate (lb/10^6 Btu) (Notes 3 and 6)	Req'd. Reduction in Potenial Emissions, % (Note 3)
Coal	SO_2: All	1.2	90 (Note 3)
	NO_x as NO_2:		
	Spreader-stoker	0.6	—
	Mass-feed stoker	0.5	—
	Pulverized coal	0.7	—
	Fluidized bed	0.6	—
	Particulate	0.05 (Note 5)	—
Oil (Resid.)	SO_2	0.8 or 0.5	90 or 0 (Note 3)
	NO_x as NO_2	0.4/0.3 (Note 4)	—
	Particulate	0.10 (Note 5)	—
Gas	SO_2	—	—
	NO_x as NO_2	0.2/0.1 (Note 4)	—
	Particulate	0.10 (Note 5)	

Notes:
1. Source: 40CFR60, Subpart Db (12/18/89).
2. For reference only: see source for details.
3. *Maximum Emissions Rate* and *Req'd. Reduction in Potential Emissions* must both be met.
4. Higher rate for heat release rates >70,000 Btu/h ft^3.
5. Separate opacity limit of 20% may be controlling.
6. Approximate SI conversions: (see Table 2).

pan, Canada and Western Europe. As in the U.S., steam generating plants have been one focus of these regulatory measures, and the primary emissions of concern from combustion processes are SO_2, NO_x and particulates. CO_2 and air toxics have received some recent attention. The detailed regulations continue to evolve rapidly and are quite country specific. However, two trends are widespread:

1. allowable emission limits for controlled pollutants will continue to decline with time, and
2. a wider array of species will be considered for control.

Without attempting to be comprehensive, the following items provide a brief overview of worldwide SO_2 and NO_x regulatory efforts. While these items will probably be quickly out of date, they provide a general indication of the range and application of control measures.

Control approaches One or more of the following of measures have typically been adopted to control emissions:

1. *Emission standards* These limit the mass of SO_2 or NO_x emitted by volume, by heat input, or by unit of time (hourly, daily, annually).
2. *Percent removal requirements* These specify the portion of the uncontrolled emissions which must be removed from the flue gas.
3. *Fuel requirements* Primarily aimed at SO_2 control, these either limit the type of fuel which can be burned or the fuel sulfur content.
4. *Technology requirements* These typically indicate the type of control technology specifically required or indicate the use of the best available control technology or reasonably available control technology at the time of installation. These requirements depend in many cases on some level of economic feasibility.

The most widely used control approach is emission standards, although this is usually combined with one or more of the other approaches. Emissions from new plants are usually more tightly controlled than emissions from existing capacity. Occasionally, older plants are not controlled, although this is changing.

Local, regional or national control of emission standards depends upon the country. In the U.S. and the Netherlands, federal standards provide minimum requirements which local authorities may tighten or apply to a broader range of applications. In Canada and Australia, federal governments can only provide emission control guidelines and local or regional governments set plant limits.

SO_2 control Based upon a recent compilation by the International Energy Agency,[5] Table 4 lists selected SO_2 emission standards for new coal-fired boilers (New Source Performance Standards).

NO_x control As with SO_2 control, NO_x emissions are most frequently regulated through emission standards of mass per unit flue gas volume or per unit heat input. Most specify NO_x emissions as NO_2. Table 5 from Reference 6 provides a summary of selected current and pending NO_x control regulations.

Evolving requirements Korea, Hong Kong, the People's Republic of China, and the countries of Eastern Europe, as well as an array of developing nations, are expected to implement SO_2 and other air pollution control strategies in the near future.[5,6]

Kinds of pollutants, sources and impacts

Air pollutants are contaminants in the atmosphere which, because of their quantity or characteristics, have deleterious effects on human health and/or the environment. The sources of these pollutants are classified as stationary, mobile or fugitive. Stationary sources generally include large individual point sources of emissions such as electric utility power plants and industrial furnaces where emissions are discharged through a stack. Mobile sources are those associated with transportation activities. Fugitive emissions generally include discharges to the atmosphere from pumps, valves, seals and other process points not vented through a stack. They also include emissions from area sources such as coal piles, landfills, ponds and lagoons. They most often consist of particulates and occur in industry related activities in which the emissions are not collected.

The focus of this chapter is stationary emission sources, particularly fired utility and industrial boiler systems. Key pollutants from these sources are SO_2, NO_x, CO and particulate matter. Another class of emissions is called air toxics. These are potentially hazardous pollutants which generally occur in only trace quantities in the effluents from fired processes. However, they are undergoing more intense examination because of their potential health effects.

During the 1980s, concern increased about the potential impact of carbon dioxide (CO_2) emissions from man-made sources on the global climate. CO_2 is one of several so-called *greenhouse* gases which are said to contribute to a potential global warming phenomenon. It is emitted from a variety of naturally occurring and man-made

Table 4
Selected International SO_2 Emission Limits for New Coal-Fired Plants (Note 1)

		Plant Size (Note 6)		Emissions Standard		
Country	Plant Type	MW_t	10^6 Btu/h	mg/Nm^3	lb/10^6 Btu	% Removal
Austria	Boilers	10 to 50	34 to 171	400	0.33	—
	Lignite-fired	>50	>171	400	0.33	—
	Hard coal	>50	>171	200	0.16	—
Belgium		50 to 100	171 to 341	2000	1.6	—
		100 to 300	341 to 1024	1200	1.0	—
		>300	>1024	400 (250 Note 2)	0.33 (0.2)	—
Canada	Utilities	All	All	740 (Note 3)	0.6	—
Denmark	Utilities	>50	>171	860 (Note 3)	0.7	—
Finland		50 to 150	>171 to 512	660	0.54	—
		>150	>512	400	0.33	—
Germany	Conventional	1 to 100	3 to 341	2000	1.6	—
	Boilers	100 to 300	341 to 1024	2000	1.6	60
		>300	>1024	400	0.33	85
	FBC boilers	>1	>3	400	0.33	75
Italy	Utilities	>100	>341	400	0.33	—
Japan	All plants	All	All	Plant specific (Note 4)		
Netherlands		50 to 300	171 to 1024	700	0.57	—
		>300	>1024	400	0.33	85
Spain	Utilities	Hard coal	—	2400	2.0	—
		Brown coal	—	9000	7.3	—
	Industry	Hard coal	—	2400	2.0	—
		Brown coal	—	6000	4.9	—
Sweden	Coal-fired	>0.5	>1.7	290	0.24	—
Taiwan		All	—	3150/4000 (Note 5)	2.56/3.25	—
UK		>700	>2388	—	—	90
USA	Utility	>73	>250	1480	1.2	70 to 90
	Industry	>29	>100	1480	1.2	90

Notes:
1. Source: IEA Coal Research, October 1989.
2. Lower limit applies from 1995.
3. Guidelines.
4. Set on a plant by plant basis according to nationally defined formulae.
5. Lower limit applies to imported coal.
6. SI conversion: 8.14 x 10^{-4} lb/10^6 Btu per mg/Nm^3, 3.412 x 10^6 Btu/MWh, 350 m^3 flue gas/GJ input and 30 GJ/tonne.

sources which include the combustion of all fossil and hydrocarbon based fuels. Obviously, improving the power cycle efficiency (more power from less fuel) and the use of fuels with less carbon content are potential methods to address CO_2 emissions from any combustion source. However, there remains disagreement in the scientific discussion of the impact of CO_2 emissions as well as the methods and level of control. Therefore, further discussion of this issue awaits scientific and public clarification and consensus.

Sulfur oxides This category of pollutants includes mainly SO_2 with small quantities of sulfur trioxide (SO_3). The main source of sulfur oxides is from the combustion of coal, with lesser amounts from other fuels such as residual oil. Based on 1985 National Acid Precipitation Assessment Program (NAPAP) data,[7,8] the utility and industrial sectors (smelters, iron and steel mills, refineries) are the largest emitters of sulfur oxides (see Table 6). In the presence of particulate matter, sulfur oxides have been related to irritation of the human respiratory system, reduced visibility, materials corrosion and varying effects on vegetation. The reaction of sulfur oxides with moisture in the atmosphere has been identified as contributing to acid rain.

Nitrogen oxides This category includes numerous species comprised of nitrogen and oxygen, although nitric oxide (NO) and nitrogen dioxide (NO_2) are the most significant in terms of quantity released to the atmosphere. NO is the primary nitrogen compound formed in high temperature combustion processes where nitrogen present in the fuel and/or combustion air combines with oxygen. The quantity of NO_x formed during combustion depends on the quantity of nitrogen and oxygen available, the temperature, the level of mixing and the time for reaction. Control of these parameters has formed the basis for a number of control strategies involving combustion process control and burner design. Based on 1985 NAPAP data, utilities account for 33% of NO_x emitted in the U.S., with the transportation sector emitting 43%. Of the total utility NO_x emissions, 89% comes from coal-fired boilers. The most deleterious effects come from NO_2 which can form from the reaction of NO and oxygen. NO_2 also absorbs the full visible spectrum and can reduce visibility. NO_x has been associated with respiratory disorders, corrosion and degradation of materials, and damage to vegetation. NO_x has also been identified as a precursor to ozone and smog formation.

Carbon monoxide This colorless, odorless gas is formed from incomplete combustion of carbonaceous fuels. CO

Table 5
Selected International NO_x Emission Limits for Coal-Fired Plants (Note 1)

	New Plants		Existing Plants	
	mg NO_2/Nm^3	lb/10^6 Btu	mg NO_2/Nm^3	lb/10^6 Btu
Austria	200 to 400	0.16 to 0.33	200 to 400	0.16 to 0.33
Belgium	200 to 800	0.16 to 0.65	—	—
Denmark	650 (Note 2)	0.53	(Note 2)	—
European Community (EC)	650 to 1300	0.53 to 1.06	—	—
Finland	200 to 400	0.16 to 0.33	400 to 620	0.33 to 0.50
Germany	200 to 500	0.16 to 0.41	200 to 1300	0.16 to 1.06
Italy	200 to 650	0.16 to 0.53	200 to 650	0.16 to 0.53
Japan	410 to 510	0.33 to 0.41	620 to 720	0.50 to 0.60
Netherlands	400 to 800	0.33 to 0.65	1100	0.90
Sweden	140	0.11	140 to 560	0.11 to 0.46
Switzerland	200 to 500	0.16 to 0.41	200 to 500	0.16 to 0.41
Taiwan	600 to 850	0.49 to 0.69	600 to 850	0.49 to 0.69
UK	650	0.53	—	—
USA	615 to 980	0.50 to 0.80	553 to 614	0.45 to 0.50 (Note 3)

Notes:
1. Source: IEA Coal Research Report, IEA/CR-30, December 1990.
2. In addition to *bubble principle* for utilities.
3. Dry-bottom wall-fired and tangential-fired only; other limits pending.
4. SI conversion: 8.14 x 10^{-4} lb/10^6 Btu per mg/Nm^3, 350 m^3 flue gas/GJ input and 30 GJ/tonne.

emissions from properly designed and operated utility boilers are a relatively small percentage of total U.S. combustion source CO emissions, most of which come from the internal combustion engine in the transportation sector. The primary environmental significance of CO is its effect on human and animal health. It is absorbed by the lungs and reduces the oxygen carrying capacity of the blood. Depending on the concentration and exposure time, it can cause impaired motor skills and physiological stress.

Particulate matter Solid and liquid matter of organic or inorganic composition which is suspended in flue gas or the atmosphere is generally referred to as particulate. Particle sizes from combustion sources are in the 1 to 100 μm range, although particles smaller than 1 μm can occur through condensation processes. Among the effects of particulate emissions are impaired visibility, soiling of surrounding areas, aggravation of adverse effects of SO_2, and human respiratory problems.

Table 6
1985 U.S. Anthropogenic Emissions
NAPAP Data (Version 2)[7,8]

	Emissions (10^3 tons)			
Category	SO_2	NO_x	VOC	TSP
Utility combustion	16,055	6,662	40	570
Industrial combustion	2,679	3,198	97	304
Other combustion	613	790	1,862	1,171
Industrial processes	2,931	926	3,715	1,099
Transportation	864	8,835	8,800	4,195
Other	4	130	7,558	1,044
Total	23,146	20,541	22,072	8,383

Notes: SO_2 — Sulfur dioxide
NO_x — Nitrogen oxides as NO_2
VOC — Volatile organic compounds
TSP — Total suspended particulate

VOC Volatile organic compounds, or more commonly VOC, represent a wide range of organic substances. These compounds consist of molecules containing carbon and hydrogen and include aromatics, olefins and paraffins. A major source is the refining and use of petroleum products. Also included among VOCs are compounds derived from primary hydrocarbons including aldehydes, ketones and halogenated hydrocarbons. The major source of these compounds is the transportation and the commercial/residential combustion sectors. VOCs are environmentally significant because of their role in the formation of photochemical smog through photochemical reactions with NO_x. Control of VOCs has been the primary means of addressing areas of ozone nonattainment. Smog arising from VOC emissions can cause respiratory problems, eye irritation, damage to vegetation and reduced visibility.

Toxic and hazardous materials This is a large category of air pollutants which could have hazardous effects. The EPA had only promulgated standards for arsenic, asbestos, benzene, beryllium, mercury, radionuclides and vinyl chlorides before the passage of the 1990 Amendments to the Clean Air Act. This Act, under Title III, established a list of 190 toxic pollutants for which emissions are to be regulated. The list includes a wide range of simple and complex industrial organic chemicals and a small number of inorganics, particularly heavy metals. The EPA has identified hundreds of categories of air toxics sources, among which are utility boilers, pulp and paper plants, and municipal solid waste incinerators.

Air pollution control technologies

The strategies for control of all emissions from a utility or industrial boiler are formulated by considering design fuels, kind and extent of emission reduction mandated, and economic factors such as boiler design, location, new or existing equipment, age and remaining life.

SO_2 control strategies and technologies SO_2 emissions from coal-fired boilers can be reduced using precombustion techniques, combustion modifications and postcombustion methods.

Precombustion These techniques include the use of oil or gas in new units or the use of cleaned (beneficiated) coal or fuel switching in existing units. By using gas, sulfur emissions can be reduced to almost zero while the use of low sulfur oil will minimize SO_2 emissions. While the low sulfur content of oil and gas is advantageous, the price volatility and availability of these fuels make them less attractive except where local circumstance dictates. Switching to oil and gas in existing boilers requires attention be given to receiving equipment, storage facilities, combustion equipment including safety systems, boiler design, and unit postcombustion FGD performance. In the case of new systems, oil or gas firing can significantly reduce steam system capital costs. Even switching from one coal to another low sulfur coal can have a dramatic impact on fuel handling, combustion and particulate collection equipment. These effects are explored in more detail in Chapters 20 and 46.

Combustion modifications These techniques are primarily used to reduce NO_x emissions but can also be used to control SO_2 emissions in fluidized-bed combustion where limestone is used as the bed material. The limestone can absorb more than 90% of the sulfur released during the combustion process. (See Chapters 16 and 29.)

Sorbent injection technologies Sorbent injection, while not involving modification of the combustion process, is applied in temperature regions ranging from those just outside the combustion zone in the upper furnace to those at the economizer and duct work following the air heater. Sorbent injection involves adding an alkali compound to the coal combustion gases for eventual reaction with SO_2. Typical calcium sorbents include limestone [calcium carbonate ($CaCO_3$)], lime (CaO), hydrated lime [$Ca(OH)_2$] and modifications of these compounds with special additives. Sodium based compounds are also used. The manner in which injected sorbents react with sulfur oxides and the efficiency of the processes depend on the temperature of injection, sorbent type, sorbent surface area, and molar ratio of sorbent to sulfur. These processes are discussed in Chapter 35.

Wet and dry scrubbing technology Worldwide, wet and dry scrubbing systems are the most commonly used technologies in the coal-fired electric utility industry. 1989 data indicate that in the U.S. approximately 20% of the coal-fired utility capacity used wet scrubbing for SO_2 emission control. Both wet and dry scrubbing use slurries of sorbent and water to react with SO_2 in flue gas, producing wet and dry waste products, respectively.

In the wet scrubbing process, a sorbent slurry consisting of water mixed with lime, limestone, magnesium promoted lime or sodium carbonate (Na_2CO_3) is contacted with flue gas in a reactor vessel. Wet scrubbing is a highly efficient (> 90% at calcium/sulfur molar ratios close to 1.0), well established technology which can produce usable byproducts.

Dry scrubbing involves spraying an aqueous sorbent slurry into a reactor vessel so that the slurry droplets dry as they contact the hot flue gas [~300F (~149C)]. The SO_2 reaction occurs during the drying process and results in a dry particulate containing reaction products and unreacted sorbent entrained in the flue gas, along with flyash. These materials are captured downstream in the particulate control equipment.

Dry scrubbing is a well established technology with considerable operational flexibility, but fouling of downstream duct work is possible. The waste residue is dry.

NO_x control technologies NO_x emissions from fossil fuel-fired industrial and utility boilers arise from the nitrogen compounds in the fuel and molecular nitrogen in the air supplied for combustion. Conversion of molecular and fuel nitrogen into NO_x is promoted by high temperatures and high volumetric heat release rates found in boilers. The main strategies for reducing NO_x emissions take two forms: 1) modification of the combustion process to control fuel and air mixing and reduce flame temperatures, and 2) postcombustion treatment of the flue gas to remove NO_x. (See Chapters 10, 13, 15 and 34.)

Combustion modification This approach to NO_x reduction can include the use of low NO_x burners, combustion staging, gas recirculation or reburning technology.

Low NO_x burners slow and control the rate of fuel and air mixing, thereby reducing oxygen availability in the ignition and main combustion zones. Low NO_x burners can reduce NO_x emissions by 50% or more, depending upon the initial conditions, are relatively low cost and are applicable to new plants as well as retrofits.

Staged combustion uses low excess air levels in the primary combustion zone with the remaining (overfire) air added higher in the furnace to complete combustion. Significant NO_x reductions are possible with staged combustion, although reducing zones and potential for corrosion and slagging exist.

Flue gas recirculation reduces oxygen concentration and combustion temperatures by recirculating some of the flue gas to the furnace without increasing total net gas mass flow. Large NO_x reductions are possible with oil and gas firing while moderate reductions are possible with coal firing. Modifications to the boiler in the form of ducting and an efficiency penalty due to power requirements of the recirculation fans can make the cost of this option higher than some of the other in-furnace NO_x control methods.

Reburning is a technology used to reduce NO_x emissions from Cyclone furnaces (Chapter 14) and other selected applications. In reburning, 75 to 80% of the furnace fuel input is burned in the Cyclone furnace with minimum excess air. The remaining fuel (gas, oil or coal) is added to the furnace above the primary combustion zone. This secondary combustion zone is operated substoichiometrically to generate hydrocarbon radicals which reduce NO formed in the Cyclone to N_2. The combustion process is then completed by adding the balance of the combustion air through overfire air ports in a final burnout zone in the top of the furnace.

Postcombustion The two main postcombustion techniques for NO_x control are selective noncatalytic reduction (SNCR) and selective catalytic reduction (SCR). In SNCR, ammonia or other compounds such as urea (which thermally decomposes to produce ammonia) are injected downstream of the combustion zone in a temperature region of 1400 to 2000F (760 to 1093C). If injected at the optimum temperature, NO_x is removed from the flue gas through reaction with ammonia. SCR is being used worldwide where high NO_x removal efficiencies are required in gas-, oil- or coal-fired industrial and utility boilers. SCR systems remove NO_x from flue gases by reaction with ammonia in the presence of a catalyst.

Particulate control technologies Particulate emissions from boilers arise from the noncombustible, ash forming mineral matter in the fuel which is released during the combustion process and is carried by the flue gas to the stack. Another source of particulate is the incomplete combustion of the fuel which results in unburned carbon particles. A brief description of the principal options for particulate emissions control in industrial and utility boilers follows while Chapter 33 provides an in depth discussion.

Coal cleaning Historically, physical coal cleaning has been applied to reduce mineral matter, increase energy content and provide a more uniform boiler feed. Although reduction in flue gas particulate loading is one of the potential benefits, coal cleaning has been driven by the many other boiler performance benefits related to improved boiler maintenance and availability and, more recently, the reduction in SO_2 emissions.

Mechanical collectors These are generally cyclone collectors and have been widely used on small boilers when less stringent particulate emission limits applied. Cyclones are low cost, simple, compact and rugged devices. However, conventional cyclones are limited to collection efficiencies of about 90% and are poor at collecting the smallest particles. Improvements in small particle collection are accompanied by high pressure drops.

Fabric filters These filters, also commonly referred to as baghouses, are available in a number of designs (reverse air, shake/deflate and pulse jet), each having advantages and disadvantages in various applications. Applications include industrial and utility power plants firing coal or solid wastes, plants using sorbent injection and dry scrubbing FGD, and fluidized-bed combustors. Collection efficiency can be expected to be at least 99.8% or greater. Fabric filters have the potential for enhancing SO_2 capture in installations downstream of sorbent injection and dry scrubbing systems as discussed in Chapter 35.

Electrostatic precipitators ESPs are available in a broad range of sizes for utility and industrial applications. Collecting efficiency can be expected to be 99.8% or greater of the inlet dust loading. ESPs are considered to be less sensitive to plant upsets than fabric filters because their materials are not as sensitive to maximum temperatures. They also have a very low pressure drop. Power usage of ESPs and fabric filters tend to be similar because the high fan power needed to overcome the higher fabric filter pressure drop is approximately equal to the power consumed in the ESP transformer rectifier sets. ESP performance is sensitive to flyash loading, ash resistivity and coal sulfur content. Lower sulfur concentrations in the flue gas can lead to lower ESP collection efficiency.

Water pollution control

U.S. legislation — Clean Water Act

The objective of the Clean Water Act (CWA) is to *restore, maintain and enhance the chemical, physical and biological integrity of the nation's waters*.[9] The Act does this by setting standards for the quality of bodies of water and limitations on effluents from industrial and municipal activity. The Federal Water Pollution Control Act of 1972 and the amendments included in the Clean Water Act of 1977 authorized the EPA to control toxic pollutants discharged into waterways from point sources. These included pipes, channels and ditches. The 1972 legislation identified 129 priority pollutants which are considered hazardous wastes and which must be limited in discharges into domestic waters. During the 1980s, regulatory activities broadened to include nonpoint sources of toxic pollutants and water quality in lakes and ground water, in addition to previously regulated water quality in rivers and streams.

Requirements under the Act Industries must achieve discharge limits based on *best practicable*, followed by *best available,* treatment technologies as determined by the EPA. Industrial facilities saw an increase in compliance from 36 to 78% between 1972 and 1982. The positive response to the CWA requirements has also had a negative result. Treatment of waste water from point sources results in large quantities of sludge which, in many cases, contain toxic hazardous wastes. The wastes are generally landfilled and have resulted in numerous and large disposal sites throughout the U.S. The effects of complying with both the CWA and the CAA have shifted the burden of ultimate disposal to land based facilities.

Power plant discharge sources

In 1982 the EPA promulgated effluent limits, pretreatment standards and new source standards for 21 major industrial categories which included steam electrical power generation. Key limits in this category for utility power plants are given in Table 7. The EPA surveyed industrial discharges to determine for each discharge which of the 129 priority pollutants were present in sufficient concentration to require national regulation. Most of the organic compound priority pollutants were excluded from the utility plant discharges because of their absence or low concentration. The EPA did not initially set limits for four types of utility plant aqueous wastes, reserving these for future rule making. These are nonchemical metal cleaning wastes, FGD waste water, runoff from materials storage and construction areas (excluding coal piles), and thermal discharges. The following describes the principal aqueous discharge streams from utility power plants.

Once-through cooling water Water from rivers, lakes or oceans is used to absorb heat from the steam condenser. The cooling water exiting the steam condenser is at an elevated temperature and can be returned to the source or pumped to a cooling tower for evaporative cooling before being returned to the steam condenser. In the former case, the cooling water contains significant concentrations of only one principal regulated pollutant, total residual chlorine (TRC), which arises out of chlorine addition for condenser fouling control. The duration of each chlorination event is limited. The concerns over TRC discharge include toxicity to living organisms and the generation of halogenated hydrocarbons.

Cooling tower blowdown When the heated cooling water from the main steam condenser is cooled in an evaporative cooling tower, a buildup in dissolved solids and suspended matter occurs. Most of this buildup is removed from the system by cooling tower blowdown. Some of the suspended matter can settle out in the cooling tower basin and is removed at infrequent intervals. All of the dissolved solids and the remaining suspended solids are removed largely by cooling tower blowdown, although a small amount is discharged by drift in cooling tower exhaust. Blowdown flow is adjusted to keep the concentration of dissolved and suspended solids below the limits required to control condenser tube fouling and corrosion. Blowdown can vary from 3 to 65% of the makeup flow, depending on whether fresh water or salt water is used and whether a portion of the recirculating stream is continuously treated for deposit forming substances. Sources of chemical pollutants in blowdown include chlorine and proprietary organic chemicals for control of biofouling, corrosion inhibitors (consisting of chromate, zinc, polyphosphates, etc.), chemicals for scale control and products of corrosion. Although some of these maintenance chemicals appear on the 126 priority pollutants list, none are permitted to be present in significant levels in cooling tower blowdown (except for chromium and zinc, which are separately regulated).

Ash handling water waste Ash produced from the combustion of fuel, whether oil or coal, is collected at different points in the combustion process. Flyash is the finer size ash collected by particulate collection systems and bottom ash is removed from hoppers at the furnace bottom. Additional hoppers at intermediate points also accumulate ash. In many cases, ash is moved from these points with sluice water, which then goes to a settling pond and can typically contain 5% of suspended solids by weight.

The ash settling pond overflow can contain dissolved and suspended solids, the quantities of which will depend on the source of the ash, the type of combustion process and the point from which it is extracted from the combustion process. In general, oil ash can contain oxides and salts of vanadium, nickel and iron, carbon, organometallic compounds and magnesium compounds when a magnesium oxide additive is used for corrosion control. Oil ash is more soluble than coal ash and settles more slowly because of its particle size. Coal ash, because of the significantly greater quantity of mineral matter in coal compared to oil, is produced in much greater quantities than oil ash (300,000 t/y versus 2000 t/y for a typical 1000 MW utility plant). Bottom ash from coal combustion tends to be a mixture of vitreous metal oxides and silica, is low in solubility and tends to settle quickly because of its coarse size compared to oil ash. Coal flyash can have solubility of several percent and, because of its fineness and the presence of low density hollow cenospheres, tends to settle slowly. Coal ash contains, in addition to the eight or nine major elemental constituents, a large number of trace elements that can appear in pond overflow and which may need to be treated by best practicable technology.

Coal pile runoff Open storage of large quantities of coal is required for an uninterrupted fuel supply to utility plants [on the average, 800 to 2400 yd^3 (611 to 1834 m^3) per megawatt of rated capacity is kept on hand]. The water and oxygen from the air react with the minerals in the coal to produce a leachate contaminated with ferrous sulfate and sulfuric acid. The low pH from the acid accelerates dissolution of many of the metals present in the coal minerals.

FGD blowdown In wet FGD systems, a portion of the absorber slurry, which is sprayed into the flue gas stream to remove SO_2, is removed from the absorber tank for dewatering. In the dewatering process, the solid reaction products are separated from the liquor. The liquor is recycled to the absorber tank where additional sorbent is added. Recycling of the liquor can result in chloride buildup which, in turn, can cause increased sulfate scaling by upsetting the sulfite/sulfate balance. This buildup can be controlled by the loss of liquor retained in the dewatered sludge or by a blowdown. An aqueous blowdown discharge would typically be a saturated solution of calcium sulfate, calcium sulfite and sodium chloride. Also, depending on flyash carryover, traces of metal ions could also be present. In setting effluent limitations in 1982, the EPA reserved regulating FGD aqueous discharge to a future date.

Table 7
1982 Adopted Aqueous Discharge Limits for Steam Power Generating Systems (Note 4)

Source and Pollutant (Note 1)	Effluent Limits, mg/l BAT (Note 2) Maximum	Average
All discharges		
pH	6 to 9	6 to 9
PCBs	No discharge	No discharge
Low volume waste (Note 5), bottom ash and flyash transport water (Note 3):		
TSS	100	30
OG	20	15
Chemical metal cleaning wastes:		
TSS	100	30
OG	20	15
Copper	1.0	—
Iron	1.0	—
Once-through cooling water, total residual chlorine (TRC)	0.2	—
Cooling tower blowdown:		
Free available chlorine	0.5	0.2
Zinc	1.0	1.0
Chromium	0.2	0.2
Other 124 priority pollutants	No detectable amount	No detectable amount
Coal pile runoff:		
TSS (1980)	50	—

Notes:
1. Nomenclature: TSS - total suspended solids; OG - oil and grease; BAT - best available technology.
2. 30 day rolling daily average (Average); maximum any one day (Maximum).
3. Best conventional technology basis.
4. Adapted from Reference 1.
5. Low volume wastes include ion exchange, water treatment, evaporator blowdown, boiler blowdown, lab and floor drains, plus FGD waste water.

Metal cleaning wastes These aqueous wastes can arise from either *chemical* or *nonchemical* cleaning of metal heat transfer surfaces in the boiler.

Chemical metal cleaning uses chemical solvents for water-side cleaning of boiler system components to remove corrosion products. Cleaning intervals are measured in years for large utility boilers, and produce three to four boiler volumes [20,000 to 100,000 gal (75,708 to 378,540 l)] of waste water per cleaning. The composition of the waste solvents depends on the construction material of the feedwater system, but largely consists of iron with lesser amounts of copper, nickel, zinc, chromium, calcium and magnesium. The disposal method for the spent solvent depends on the type of chemical cleaning solvents used. When hydrochloric acid based solvents are used, spent solvent is treated on-site by neutralization and is discharged subject to the effluent limits in Table 7 or more stringent water quality standards. With approval from appropriate regulating bodies, organic based solvent wastes are often incinerated in other operating boilers at the site. The metals in the chemical cleaning wastes are retained with the normal boiler ash.

Nonchemical cleaning is used to remove fireside deposits by means of high pressure jets of water. The waste water can contain the same metals and pollutants contained in the ash deposits being removed. Because the deposit composition varies with position in the boiler, the wash water composition will depend on the location of the area being cleaned. These waste waters may be classified as either low volume wastes or metal cleaning wastes and are treated according to the corresponding effluent limits.

Low volume wastes These include discharges from ion exchange water treatment, evaporator blowdown, boiler blowdown, cooling tower basin cleaning, laboratory and floor drains, and drains and losses from recirculating house service water systems. FGD blowdown is also included until the EPA develops specific regulations for this stream. By EPA definition, low volume wastes are those from all sources taken collectively as if they were from one source. Excluded are those wastes for which specific effluent limits are established.

Water pollution control technologies

The technologies for waste water treatment used to meet limits for discharge include clarification and filtration. (See also Chapter 42.)

Clarification This is used to settle out larger suspended particles and condition smaller colloidal particles to make them settle and allow filtration for removal. A pond, reservoir or tank is used to allow larger particles to settle in a matter of hours. The finer particles overflow and are made to settle more quickly by the addition of chemical agents, coagulants and polymers that cause agglomeration to sizes large enough to settle out of suspension.

Filtration This uses a porous barrier across flowing liquid to remove suspended materials. Filtration can be used to supplement clarification and permits reducing suspended solids to the parts per billion level. Filter types include sand filters which are generally slow and do not handle fine clay well. Preconditioning with coagulants can improve filtration rates. Dual media filters improve on sand filters by superimposing a coarse, granular material over the fine bed. This allows more of the filter bed to be used, reduces head loss, and provides higher flow rates and longer operating cycles before cleaning.

As required, and with approvals from appropriate regulating bodies, final waste stream pH is controlled by combining various plant streams to provide a neutral pH product. Where needed, acid or alkali addition can be used to achieve the final pH. Other treatments are also available to address other criteria pollutants where concentration warrants.

In selected cases, zero discharge water management is provided which does not return any waste water to water sources. Effectively all water brought into the plant is evaporated through cooling towers, ponds or stack. Residual solids are then sent for disposal.

Solid waste disposal

The Resource Conservation and Recovery Act

The rapid growth of industrial activity and use of consumer goods by our society have resulted in an explosive growth in solid wastes. One of the first attempts to protect health and the environment, reduce waste, conserve natural resources and control hazardous waste production was the Solid Waste Disposal Act of 1965. This was followed in 1976 by the Resource Conservation and Recovery Act (RCRA) which amended the original Act to ensure proper future solid waste management.

The RCRA requires improved solid waste management practices, defines what constitutes hazardous waste and greatly expanded provisions for hazardous waste management. Three notable parts of the Act with far reaching implications are Subtitles C, D and I. Revisions made in 1984 were significant in expanding the regulatory scope of the RCRA through the Hazardous and Solid Waste Amendments.

The definition of a hazardous waste is very broad. It is based on the premise that a material is hazardous when its quantity, concentration or physical/chemical/infectious characteristics *(1) cause, or significantly contribute to, an increase in mortality, or an increase in serious irreversible or incapacitating reversible illness, or (2) pose a substantial present or potential hazard to human health or the environment when improperly treated, stored, transported or disposed of, or otherwise managed.*[10]

Under Subtitle C, hazardous waste can include virtually any type of waste (solid, semisolid, liquid and gaseous) which fits one or more of the following criteria:

1. possesses the characteristics of ignitability, corrosivity, reactivity and toxicity as determined by standard analytical tests and procedures (commonly referred to as a characteristic hazardous waste).
2. is listed as a specific hazardous waste (commonly referred to as a listed hazardous waste).
3. is a mixture of wastes which contains a listed hazardous waste.
4. has not been excluded from RCRA regulation as a hazardous waste.
5. is produced as a byproduct from the treatment of any hazardous waste.

Listed hazardous wastes fall into three categories based on their sources:

1. *Nonspecific source wastes* These may be derived from various industrial processes and are viewed as generic in nature, such as degreasing solvents and electroplating waste water sludges.
2. *Specific source waste* This type of waste is specifically named for and identified in terms of the industrial process from which it is produced, i.e., K047, pink/red water from TNT operations; K050, heat exchanger bundle cleaning sludge from the petroleum refining industry.
3. *Commercial chemical products* These consist of specific chemicals such as organic and inorganic compounds, pesticides and often products which are no longer of use and are identified for disposal.

In the enactment of the RCRA, there were a number of legislative exclusions of waste types which were produced in very large quantities but did not present a danger to health or the environment, or that were covered by other environmental regulations. Some of the exclusions are of significance to the power industry and the management of municipal solid wastes. Among the excluded wastes were household wastes, agricultural wastes and wastes from municipal resource recovery plants. In 1980 additional temporary exclusions were made to include wastes from fossil fuel combustion, mining operations, and oil and gas explorations. These exclusions are being examined by the EPA for possible regulation under Subtitle C.

The general trend, whether through federal or state and local action, is toward tighter control and restrictions. Depending on the state and local jurisdiction, high volume waste streams from power plants such as scrubber sludge, flyash and bottom ash are subject to different and highly variable disposal requirements. In some cases, stabilization of the solids is required. In addition, landfills are beginning to use leachate collection systems with single or double linings and extensive monitoring wells.

Kinds of solid wastes

The principal solid waste streams in coal- and oil-fired utility boilers include the following:

1. *Bottom ash* is that portion of fuel ash which falls to the bottom of the furnace or from the stoker discharge. In coal-fired Cyclone furnace boilers, the bottom ash consists of slag which drops from the bottom of the furnace into a slag tank for solidification.
2. *Flyash* is the finer ash material which is borne by the flue gas from the furnace to the back end of the boiler; it drops out in the economizer and air heater hoppers or is collected by particulate control equipment.
3. *Pyrite* is iron sulfide, an impurity which is separated from coal in the pulverizer and which is combined with bottom ash for disposal.

FGD waste characteristics depend on the particular technology used:

1. *Wet scrubbing (calcium based system)* Using natural oxidation produces a wet sludge containing a mixture of calcium sulfite and calcium sulfate reaction products, trace amounts of flyash and unreacted limestone. In a forced oxidation system, the principal difference in the waste is that the reaction product is almost totally in the form of calcium sulfate or gypsum, which is more easily dewatered to a filter cake for landfill or other use.
2. *Dry scrubbing* Waste is dry and contains calcium sulfite, calcium sulfate, flyash and unreacted sorbent (hydrated lime).
3. *Dry lime injection* Waste is dry and contains calcium sulfate, flyash and a large proportion of calcium oxide (CaO).

Solid waste treatment methods

In order to dispose of waste materials from wet collection systems, treatment methods are applied to ultimately produce a solid. These methods include dewatering, stabilization and fixation and are designed to achieve waste volume reduction, stability and better handling, or liquid recovery for reuse.

Dewatering This is used to physically separate water from solids to increase solids content of the product and recover water for further treatment and potential reuse.

A settling pond is the simplest method for dewatering, is not sensitive to inlet solids content, requires low maintenance and is highly reliable. Ponds are often used for ash or limestone scrubber slurries. Sizing provides low flow velocity so that solids can settle undisturbed by gravity. Settling ponds are unpopular with regulatory agencies, require substantial acreage and must be shut down for solids removal.

Thickeners are large cylindrical tanks with a center column that drives radial rakes extending from the bottom of the shaft. The rakes carry plows to stir material on the bottom which slopes toward the center. (See Chapter 35 and 42.) The plows push settled material toward the underflow discharge. Thickeners rely on gravity to separate high specific gravity solids and are often applied to dewatering wet scrubber slurry. Although thickeners are complicated and have high capital and maintenance costs, they have high throughput rates and require less land area than settling ponds.

Cyclone collectors or hydroclones are sometimes used in place of thickeners to remove solids from slurries by centrifugal and liquid shear effects. Cyclones separate and collect particles down to a particular size, with finer particles staying with the liquid overflow. Cyclones do not separate material less than 5 μm effectively and are not efficient with slurries containing more than 15% solids. They are low in cost, have low space requirements and produce low solids content in the liquid fraction and a high liquid content in the solids fraction.

Vacuum filters, either of the drum or belt type, are generally used for second stage dewatering of wet scrubber slurries. They take little space and produce a high solids content product, up to 65% for FGD slurry and 75% for ash slurry. However, vacuum filters are higher in cost and maintenance and are mechanically complex.

Stabilization This increases solids content of waste by adding dry solids such as flyash. Stabilization is applied to impart greater physical stability to the waste, making it easier to place in the landfill and making it less susceptible to future problems. Stabilization and fixation are generally applied to scrubber wastes as the final treatment step after dewatering. Bottom ash and flyash, because of their granular nature, generally dewater easily and do not require stabilization for disposal. For stabilization, a dry solid such as soil or flyash is mixed with the waste slurry and spreads the water in the waste over a larger mass of solids. Also, there is improvement in particle size distribution which leads to closer packing, lower permeability and lower combined volume. Stabilization can be reversible and if the waste is rewetted it may fluidize and fail structurally.

Fixation This involves the addition of an agent such as lime to produce a chemical reaction to bind free water and produce a dry product. Fixation includes a number of processes. Mixing suitable proportions of scrubber slurry with alkaline flyash containing sufficient CaO produces a chemical reaction which results in a material with compressive strength comparable to concrete and with very low permeability. Both characteristics contribute to ease of placement and minimal leaching problems.

When the flyash does not have sufficient alkalinity, lime may be added with the flyash scrubber slurry to produce the cementitious reaction. Four percent addition of lime has produced material with the necessary physical properties for disposal or use. The cured material is suitable for structural fill, providing a site which can be used for building construction after completion of the landfill. Comparable fixation reactions with scrubber sludge have been obtained with additions of 5 to 10% of blast furnace slag or Portland cement.

Disposal and utilization methods and requirements

Ultimate disposition of utility plant wastes (ashes and FGD residues) is by disposal (in landfills or impoundments) or by utilization. Where disposal is used, the waste stream is analyzed, and the site is permitted and approved by the appropriate regulatory agencies.

Disposal methods These can be either wet or dry, depending on the physical condition of the material. Wet disposal requires construction of a pond which may be below or above grade with impermeable barriers or dikes provided. Below grade construction may be considered and depends on suitable geology and hydrology at the site. With wet disposal, the waste is placed in slurry or liquid. After placement and settling, the liquid which has separated is collected, treated and either released or recycled. Dry disposal can use a simple method of landfill construction in which the waste is placed and compacted to form an artificial hill. The trend is toward dry disposal because of smaller volumes, more options for site or material reclamation, and the developing interest in dry scrubbing. Baghouse particle collection systems would also encourage the use of dry disposal.

Utilization methods These become more attractive as waste management costs increase. Bottom ash, flyash and boiler slag are used in applications where they can be substituted for sand or gravel. The characteristics of boiler slag and bottom ash also make these materials useful for blasting grit, roofing granules and controlled fills. Flyash, because of its chemistry and physical properties, is applicable in the manufacture of Portland cement and concrete mixes. The value of these materials is so low that the cost of transportation severely limits their use to applications close to the producing power plant.

FGD byproduct use is potentially in the areas of agriculture, metals recovery, sulfur recovery and gypsum. Agricultural use is limited to waste which contains lime; this can be substituted for agricultural lime. However, trace elements from flyash contamination could have an unacceptable impact and make wide use doubtful. Use for metals recovery is limited by undeveloped technology and questionable cost effectiveness. Use for sulfur recovery is limited by incomplete technology development, low market price of sulfur and large amounts of residual byproduct after-sulfur extraction.

Only FGD waste from forced oxidation wet scrubbing systems, which consists of almost pure gypsum, has seen some commercial use for drywall production.

References

1. Rice, J.K., "Legislation and pollution sources," appearing in *Standard Handbook of Power Plant Engineering*, T.C. Elliot, ed., McGraw-Hill, New York, 1989.

2. Corbitt, R.A., ed., *Standard Handbook of Environmental Engineering*, McGraw-Hill, New York, 1990.

3. Clean Air Act, 42 USCA S7401 *et seq*., Sec. 101 (b) (1).

4. Title 40, Code of Federal Regulations, Part 60, Subparts Ca, D, Da, Db, Dc, E, Ea, and BB, U.S Government Printing Office, Washington, D.C., July 1, 1991.

5. Vernon, J.L., "Market impacts of sulphur control: The consequences for coal," Report IEA/CR18, International Energy Agency/Coal Research, London, October 1989.

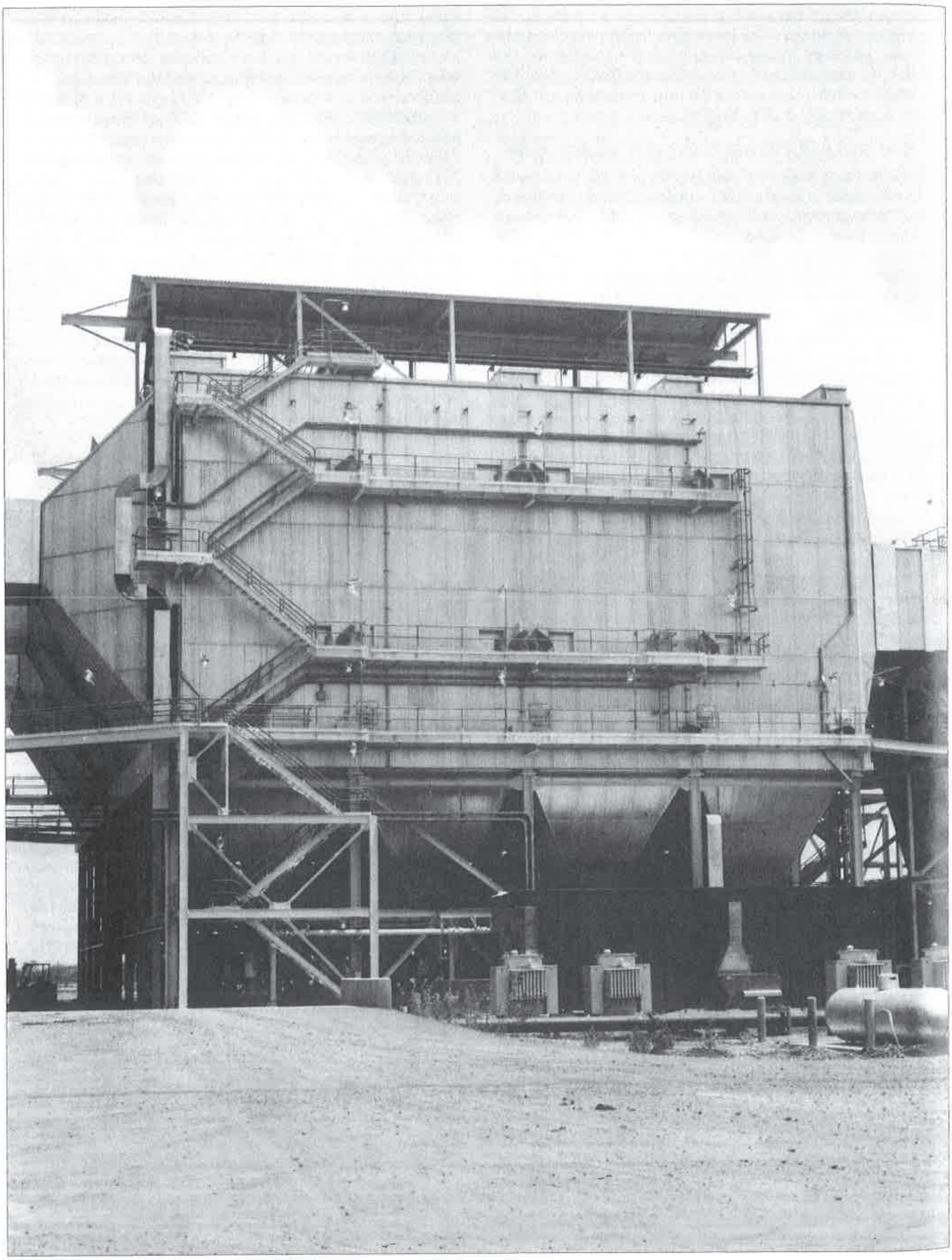
6. Hjalmarsson, A.-K., and Soud, H. N., "Systems for controlling NO_x from coal combustion," Report IEACR/30, International Energy Agency/Coal Research, London, December 1990.

7. Zimmerman, D., *et al*., "Anthropogenic emissions data for the 1985 NAPAP inventory — final report," U.S. Govt. Report No. EPA-600/7-88-022, November 1988.

8. Saeger, M., *et al*., "The 1985 NAPAP emissions inventory (version 2): Development of annual data and modelers tape," U.S. Govt. Report, EPA-600/7-89-012a, November 1989.

9. Clean Water Act, 33 USCA S1251 *et seq*., Sec. 101 (a).

10. Resource Conservation and Recovery Act, 42 USCA S9601 *et seq*., Sec. 1004 (5).



Large utility electrostatic precipitator installation.

Chapter 33
Particulate Control

As steam is generated by the combustion of most fossil fuels, the flue gas carries particulate matter or ash from the furnace. Except for natural gas, all other fossil fuels contain some quantity of ash or noncombustibles which form the majority of the particulate. Unburned carbon also appears as particulate. Combustion in most steam generation applications using nonfossil fuel also produces particulate. Control is needed to collect this material and to limit its release to the atmosphere.

All coals contain some amount of ash. Content varies depending on the type of coal, location, depth of mine and mining method. In the United States (U.S.), eastern bituminous coals typically contain 5 to 15% ash while the western subbituminous coal ash content may range from 5 to 30% ash by weight. Texas lignites also contain up to 30% ash. Mining methods on thin seams of coal may also contribute to higher ash quantities.

When coal is burned in conventional boilers, a portion of the ash drops out of the bottom of the furnace while the remainder of the ash is carried out of the furnace in the flue gas. It is this remaining ash (*flyash*) that must be collected before exhausting the flue gas to the atmosphere.

Different combustion methods contribute different proportions of the total coal ash content to the flue gas. With pulverized coal firing, 70 to 90% of the ash is carried out of the boiler with the flue gas. A stoker-fired unit will emit about 40% of its ash in the flue gas along with some amount of unburned carbon. With cyclone firing, only 15 to 30% of the ash is normally carried by the flue gas. On circulating fluidized-bed boilers, all of the ash, along with the fluidized-bed material, is carried by the flue gas. Therefore, the selection and design of particulate control equipment are closely tied to the type of firing system.

An American Society for Testing and Materials (ASTM) spectrographic analysis test of a coal sample reveals the major ash components and determines total ash content. Ash constituents are typically reported in the oxide form and include silicon dioxide, titanium dioxide, iron oxide, aluminum dioxide, calcium oxide, magnesium oxide, sodium oxide, potassium oxide, sulfur trioxide and diphosphorous pentoxide. Trace quantities of many more elements are also found in ash. The proportion of the major constituents varies significantly between coal type and mine location. The analysis and composition of flyash are discussed in greater detail in Chapters 8 and 20.

Other significant coal ash properties are particle size distribution and shape, both of which are dependent on the type of firing method. Stoker-fired units generally produce the largest particles. Pulverized coal-fired boilers produce smaller, spherical shaped particles of 7 to 12 microns (Fig. 1). Particles from cyclone-fired units, also mostly spherical, are smaller yet. Fluidized-bed units produce a wide range of particles that are generally less spherical and are shaped more like crystals. Knowledge of ash properties is important in the selection of the correct particulate control equipment.

Regulation of particulate emissions

Particulate control equipment was first used by utilities in the 1920s and before that time in some industrial applications.[1] Prior to 1971, however, controls were installed mostly on a best effort basis. In 1971, the first Environmental Protection Agency (EPA) performance standard limited outlet particulate emissions to 0.1 lb/10^6 Btu (123 mg/Nm^3 at 6% O_2) heat input and stack opacity to 20% for those units larger than 250 x 10^6 Btu/h (73.3 MW$_t$) heat input. *Opacity*, measured by a transmissometer, is the portion of light which is scattered or absorbed by particulate as the source of light passes across a flue gas stream. Therefore, both the amount and appearance of the stack emissions are regulated. Since 1979 the EPA New Source Performance Standards (NSPS) for particulate control

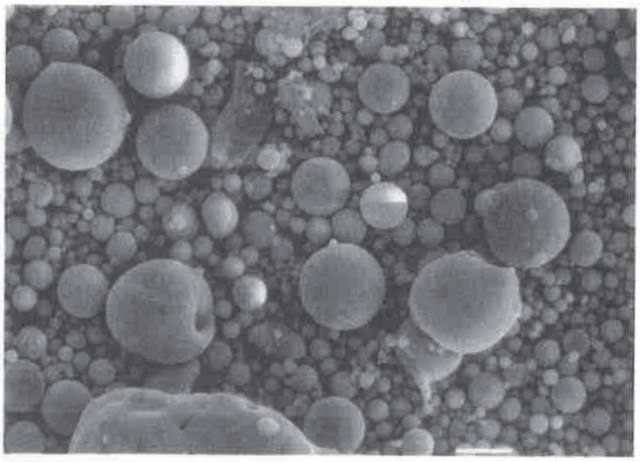


Fig. 1 Flyash from pulverized coal (magnified x 1000).

permit a maximum of 0.03 lb/10^6 Btu (36.9 mg/Nm^3 at 6% O_2) heat input for these units. A 20% opacity is still permissible.

Federal and state EPA regulations set the primary guidelines for particulate emissions. In addition, many local regulatory bodies have established stricter regulations than those set by the EPA. There are separate emissions standards for a variety of fired processes including steam generators firing coal, oil, refuse and biomass. Currently there are three major classification levels for steam generating units: one for units greater than 250 x 10^6 Btu/h (73.3 MW_t), one for the 100 to 250 x 10^6 Btu/h (29.3 to 73.3 MW_t) units and a third for those units less than 100 x 10^6 Btu/h (29.3 MW_t) heat input.[2, 3] Finally, if a new plant is in a nonattainment area, the permissible particulate emissions and opacity may be significantly reduced from nominal control levels. (See Chapter 32.)

Particulate control equipment

Particulate emissions from the combustion process are collected by particulate control equipment (Fig. 2). This equipment must remove the particulate from the flue gas, keep the particulate from re-entering the gas and discharge the collected material. There are several major types of equipment available including electrostatic precipitators, fabric filters, mechanical collectors and venturi scrubbers. Each of these uses a different collection process with different factors affecting the collection performance.

Electrostatic precipitators

An electrostatic precipitator (ESP) electrically charges the ash particles in the flue gas to collect and remove them. The unit is comprised of a series of parallel vertical plates through which the flue gas passes. Centered between the plates are charging electrodes which provide the electric field. Fig. 3 is a plan view of a typical ESP section which indicates the process arrangement.

Charging

The collecting plates are typically electrically grounded and are the positive electrode components. The discharge electrodes in the flue gas stream are connected to a high voltage power source, typically 55 to 75 kV DC, with a negative polarity. An electric field is established between the discharge electrodes and the collecting surface. As the flue gas passes through the electric field, the particulate takes on a negative charge which, depending on particle size, is accomplished by field charging or diffusion.

Collection

The negatively charged particles are attracted toward the grounded collection plates and migrate across the gas flow. Some particles are difficult to charge, requiring a strong electric field. Other particles are charged easily and driven toward the plates but also may lose the charge easily requiring recharging and recollection. Gas velocity between the plates is also an important factor in the collection process since lower velocities permit more time for the charged particles to move to the collection plates and reduce the likelihood of re-entrainment. In addition, a series of plates and discharge electrodes are necessary to maximize overall particulate collection by increasing the opportunities of the individual ash particles to be charged and collected.

The ash particles form an ash layer as they accumulate on the collection plates. The particles remain on the collection surface due to the forces from the electric field as well as the molecular and mechanical cohesive forces between particles. These forces also tend to make the particles agglomerate or cling together.

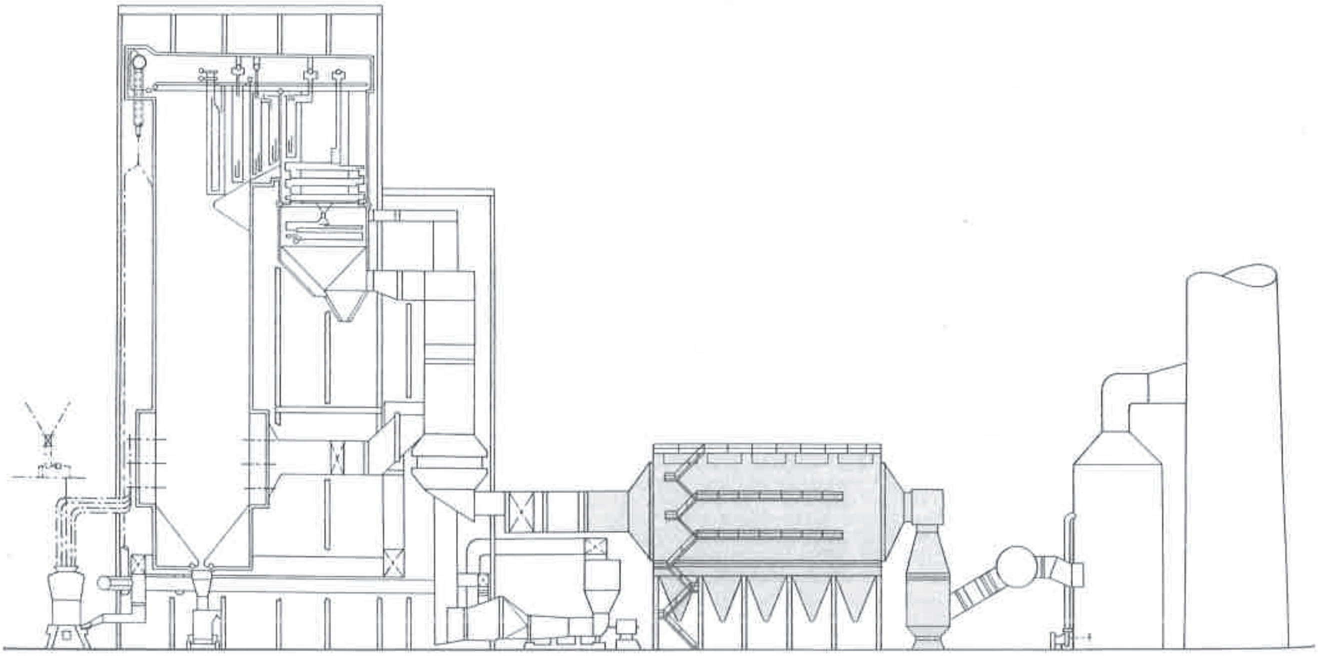


Fig. 2 Particulate control equipment — plant side view.

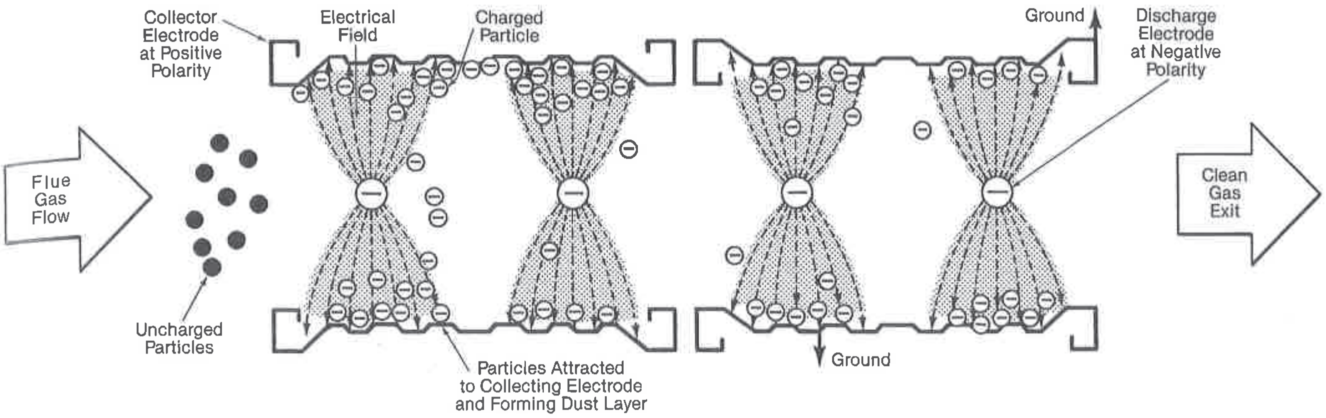


Fig. 3 Particle charging and collection within an ESP.

Rapping

The ash layer must be periodically removed. The most common removal method is rapping which consists of suddenly striking the collection surface; this rapping force dislodges the ash. Because particulate tends to agglomerate, the ash layer is removed in sheets. This sheeting is important to prevent the re-entrainment of individual particles into the flue gas stream, requiring recharging and collection downstream.

While most of the particles are driven to the collection surface, some positively charged particles attach to the discharge electrodes. A separate rapping system is therefore used to clean these electrodes to maintain the maximum charging forces.

Ash removal

The dislodged particulate falls from the collection surface into hoppers. Once the particulate has reached the hopper it is important to ensure that it remains there until the hopper is emptied. (See Chapter 23 for hopper ash removal methods and equipment.)

Precipitator sizing factors

An ESP is sized to meet a required performance or particulate collection efficiency. The sizing procedure determines the amount of collection surface to meet the specified performance. An equation which relates the collection efficiency (E) to the unit size, the particle charging and the collection surface is the Deutsch-Anderson equation:[1]

$$E = 100\left(\frac{\text{Inlet dust loading} - \text{Outlet dust loading}}{\text{Inlet dust loading}}\right) \tag{1}$$

$$1 - E = e^{\frac{-wA}{V}} \tag{2}$$

or

$$A = \left[\ell n\left(\frac{1}{1-E}\right)\right]\frac{V}{w} \tag{3}$$

where

E = ESP removal efficiency, %
w = migration velocity, ft/min (m/s)
A = collection surface area, ft^2 (m^2)
V = gas flow, ft^3/min (m^3/s)

Migration velocity is the theoretical average velocity at which the charged particles travel toward the collection surface. This velocity is dependent upon how easily the particulate is charged, and the value is normally selected by empirical means based on experience. The factors which affect migration velocity are the fuel and ash characteristics, the operating conditions and the effects of gas flow distribution.

These factors also have an effect on the ability of the particulate to accept a charge. A commonly used indication of this effect is resistivity, measured in ohm-cm. Fig. 4 illustrates typical resistivity curves for two fuel ashes. High resistivity ashes result in low migration velocities and large collection surface areas while average resistivity ashes result in moderately sized surface areas.

Fuel and ash characteristics The fuel and ash constituents which reduce resistivity or which are favorable to ash collection in an ESP include moisture, sulfur, sodium and potassium. Applications with sufficient quantities of these components usually result in moderately sized precipitators. Constituents which hamper ash collection and increase outlet emissions include calcium and magnesium. High percentage concentrations of these items without offsetting quantities of the favorable constituents result in poorer collection and larger precipitators.

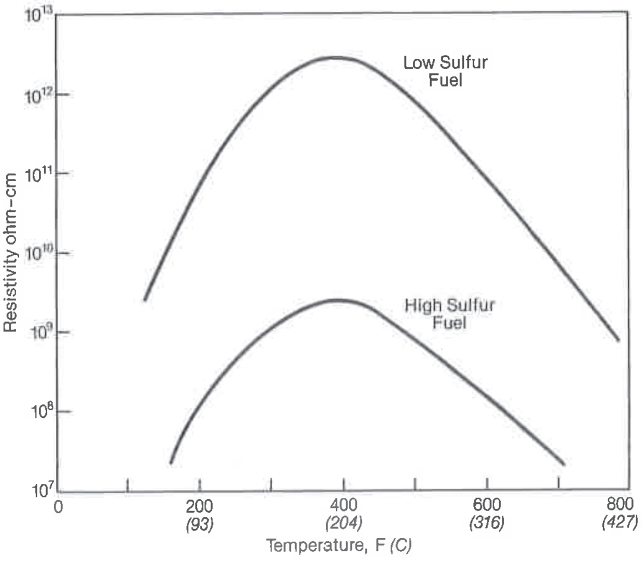


Fig. 4 Typical ash resistivity.

The fuel and ash constituents and their relative quantities must be reviewed in the sizing process to determine the overall effect on migration velocity. The migration velocity/resistivity can then be altered to some extent by controlling the content of the critical constituents.

Operating conditions The design operating conditions from the boiler or process also affect precipitator sizing and performance. As indicated on the resistivity curve, gas temperature has a direct effect on resistivity and on the gas volume passing through the ESP. Gas flow from the boiler also has an effect on sizing as indicated by the Deutsch-Anderson equation. There is an optimum gas velocity range within an ESP for maximum performance which must be considered as part of the design selection.

In addition to the quantity of particulate sent to the precipitator, particle size also affects ESP design and performance. A particle size distribution versus collection efficiency curve (Fig. 5) indicates that an ESP is less efficient for smaller particles (less than 2 microns) than for larger ones. Therefore, ESP applications with a high percentage of particles less than 2 microns will require more collection surface and/or lower gas velocities.

Flow distribution Maximum ESP efficiency is achieved when the gas flow is distributed evenly across the unit cross section. Uniform flow is assumed in the ESP sizing calculations and should be verified during the design stage by using a flow model. These models should include the precipitator as well as the inlet and outlet flues. Flow uniformity is typically achieved by installing distribution devices in the flue transition sections immediately upstream and downstream of the ESP. Hopper design must also prevent high velocity areas to avoid flyash re-entrainment. The industry standard for flow distribution and modeling is the Industrial Gas Cleaning Institute EP-7.[5]

Precipitator components

All ESPs have several components in common (Fig. 6) although there is some shape and size variation between units.

Discharge electrodes As described in the section on charging, the discharge electrodes, connected to the high voltage power source, are located in the gas stream and serve as the source of the corona discharge. These electrodes are the central components of the discharge system which is electrically isolated from the grounded portions of the ESP. An electrical gap of 6 to 8 in. (152 to 203 mm), depending on plate spacing, must be maintained throughout the ESP between the discharge and the grounded components.

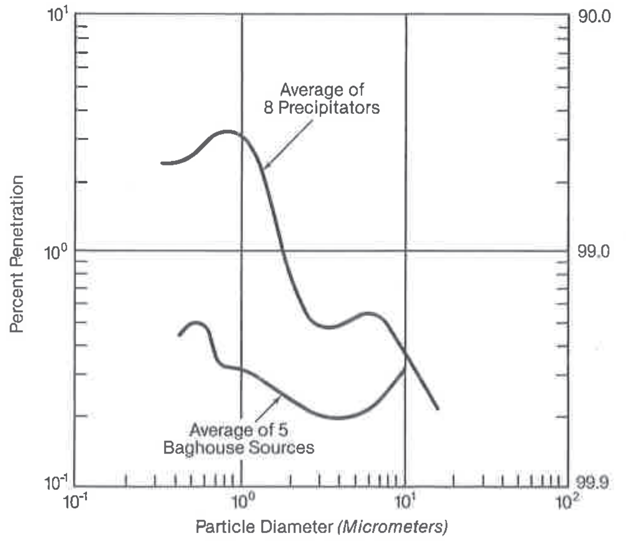


Fig. 5 Summary of fine particulate collection (adapted from Reference 4).

Discharge electrodes are found in several shapes. Common types include the rigid frame, rigid electrode and weighted wire. The rigid frame, shown in Fig. 7, consists of strips of electrode supported between sections of frame tubing. Each frame is attached to a structural carrier, both front and rear. This assembly is supported by insulators forming a four point suspension system. The rigid electrode consists of a member with proprietary shape which is top supported and hangs the full height of the precipitator. The typical rigid electrode top support is also a frame hanging from insulators. The lower ends of the rigid electrode have a guide bar and side to side spacers. The third type of electrode, or weighted wire design, consists of a round discharge electrode (wire) supported at the top and held straight and in tension with a weight at the bottom. The upper frame is supported from insulators and there is a lower steadying frame to guide and space the electrodes.

For highest equipment reliability, either the rigid frame or rigid electrode is the most common configuration. Discharge electrode failure in the form of broken wires has been a recurring problem with the weighted wire electrodes, particularly with lengths of 30 ft (9.1 m) or more, which results in performance deterioration.

Collection surface As previously stated, the collection surface area in the Deutsch-Anderson equation is the total plate area required for particulate collection. Shown in Fig. 6, the collection surface typically consists of a series of roll formed collector plates assembled into a curtain and supported from the top. The curtains are spaced in rows across the width of the precipitator, typically on 12 or 16 in. (305 or 406 mm) centers. In depth, the curtains are arranged into fields. For calculating surface area, the curtain assembly is treated as a plane and includes both sides of the plates. The rolled plates can be up to 50 ft (15.2 m) in length with a shop straightness tolerance of 0.5 in. (12 mm). Collector curtains may also be large flat plates with stiffener bars added to maintain straightness. For optimum performance with a uniform electric field and with no electrical arcing (high current spark), the alignment of collection surface and electrodes must be maintained within tight tolerances.

Rapping systems As shown in Fig. 6, the most effective method of cleaning the collector curtains is to rap each one separately and in the direction of gas flow. This method assures that each curtain receives a rapping force. The rapping system shown is a tumbling hammer type, where the hammer assemblies are mounted on a shaft extending across the ESP in a staggered arrangement. The shaft is turned slowly by an external drive controlled by timers for rapping frequency and optimum cleaning. Hammer size is selected to match the application and size of the collector curtain. Although not as effective for many applications, top rapping of the collection surface is also popular. Typically, more than one collector curtain is rapped at a time with this method, and the rapping force is in the downward direction on the top edge of the curtains. Both a drop rod and magnetic impulse are the drive mechanisms used.

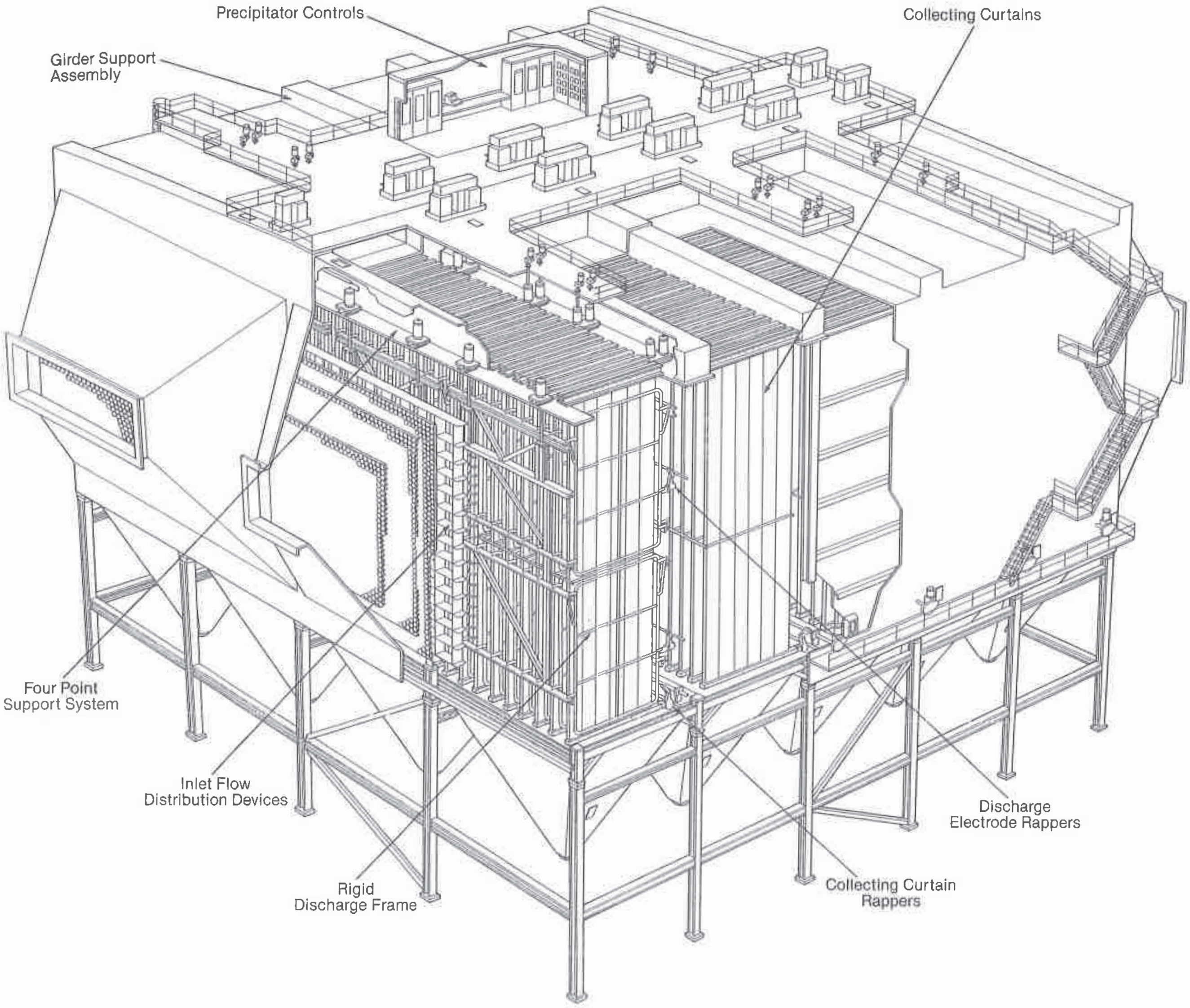


Fig. 6 B&W/Rothemuhle rigid frame electrostatic precipitator.

Due to the difficulty of cleaning high resistivity flyash from the collection surface, considerable tests have been performed to ensure that adequate rapping forces are transmitted across the entire collection surface. A minimum acceleration of 100 g's applied at the farthest point from impact has been established as an industry standard.

Typically, rapping of the rigid frame discharge electrodes is accomplished using a tumbling hammer system as shown in Fig. 7. The hammer assemblies are mounted in a staggered arrangement on a shaft across the width of an electrical section. Note that a smaller hammer than that used for the collector system is required for proper cleaning of the discharge electrodes. An external drive unit mounted on the precipitator roof is used to slowly turn the rapper shaft and, because it is attached directly to the carrier frame, the drive shaft must also be electrically isolated with an insulator. As with the collector system, top rapping of the discharge electrodes is another method of cleaning.

A rapping system is sometimes used on the flow distribution devices at the precipitator inlet. On those applications where the particulate is sticky or tends to accumulate, a rapping system is needed to keep the surfaces clean and to allow the distribution devices to provide uniform flow to the precipitator inlet at an acceptable pressure loss.

Enclosure As shown in Fig. 6, the structure forming the sides and roof of an ESP is a gas-tight metal cased enclosure. The structure rests on a lower grid, which serves as a base and is free to move as needed to accommodate thermal expansion. All of the collecting plates and the discharge electrode system are top supported from the plate girder assemblies. The entire enclosure is covered with insulation and lagging. Access doors in the casing and adequately sized walkways between the fields assist in maintenance access for the internals.

Materials for the precipitator enclosure and internals are normally carbon steel, ASTM A-36 or equivalent, because gas constituents are noncorrosive at normal operating gas and casing temperatures. Projects with special conditions may warrant an upgrade in some component materials.

Hoppers Metal pyramid shaped hoppers are supported from the lower grid and are made of externally stiffened

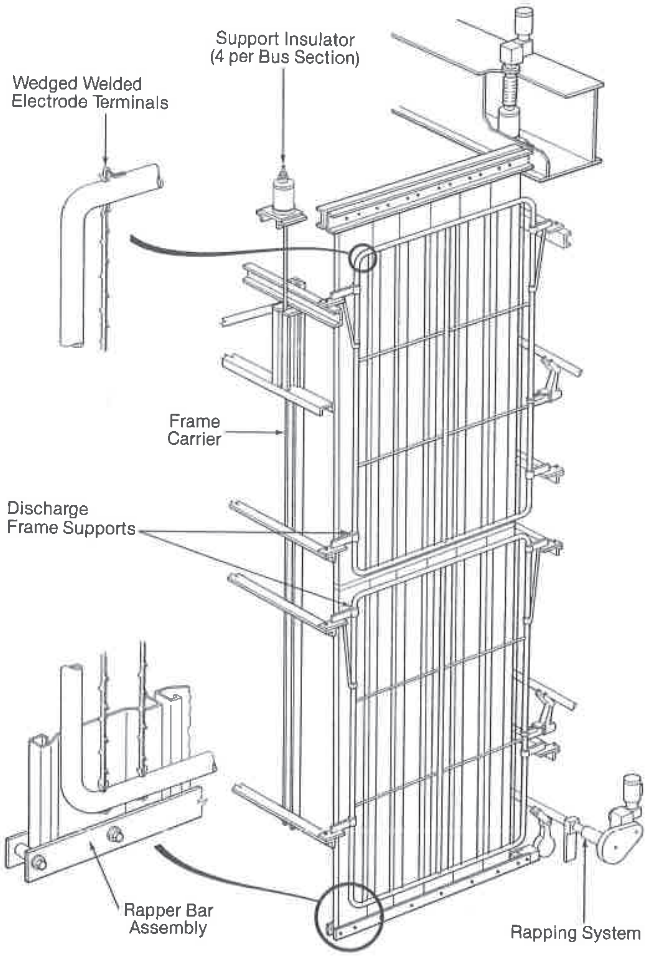


Fig. 7 Rigid frame discharge electrode and rapping system for an ESP.

casing. The hoppers provide the lower portion of the overall enclosure and complete the gas seal. Their sides are designed with an inclination angle of at least 60 deg from horizontal. Hoppers are generally designed as particulate collection devices which can store ash for short periods of time when the ash removal system is out of service.

Because many ash removal systems are noncontinu-ous, the following items are normally supplied with the precipitator hoppers to ensure good particulate removal: hopper heaters, electromagnetic vibrators, poke holes, anvil bars and level detectors. Hot air fluidizing systems are also sometimes supplied to assist in ash removal.

Power supplies and controls A transformer rectifier (TR) set along with a controller supply the high voltage power to the discharge electrode system. Several TR sets are normally needed to power a precipitator. With this combination of electrical components, the single-phase 480 V AC line voltage is regulated in the controller and then transformed into a nominal 55,000 to 75,000 V before being rectified to a negative DC output for the discharge system. Electrically, a precipitator most closely resembles a capacitive load. Due to the capacitive load and the nature of the precipitator internals, the TR set must be designed to handle the current surges caused by arcs between the discharge electrodes and the grounded collection surface. A current-limiting reactor in series with the TR set primary also helps to temporarily limit the current surges.

Traditionally, a voltage controller tries to maximize the voltage input to the precipitator. To achieve this input and when operating as designed, the controller must periodically raise the voltage to the point of sparking between the discharge electrode and the collection surface. The controller must then also detect the sparks and reduce the voltage to avoid an arc.

Today's microprocessor electronics with quick response times, interface advantages and programming capabilities provide many functions to optimize particulate collection.

Applications and performance

Utility Because coal is the most common fuel for steam generation, collection of the coal ash particles is the greatest use of a particulate collector. The electrostatic precipitator has been the most commonly used collector. To meet the particulate control regulations for utility units and considering the resulting high collection efficiency, special attention must be given to details of precipitator sizing, rapping, flow distribution and gas bypass around the collector plates. The result will then be a collector which can be confidently and consistently designed and operated to meet the outlet emissions requirements. Operating collection efficiencies which exceed 99.9% are common on the medium and higher ash coals with outlet emissions levels of 0.01 to 0.03 lb/10^6 Btu (12.3 to 36.9 mg/Nm^3 at 6% O_2) heat input common on all coals.

Industrial Other common noncoal-fired industrial units where ESPs are successfully being applied include municipal refuse incinerators and wood-, bark- and oil-fired boilers. For these, the resistivity of the ash in the flue gas is typically lower than coal flyash so an ESP of modest size will easily collect the particulate. The moisture content in the refuse, wood and bark is the major contributor to the low resistivity. The carbon content of the residue, ash and unburned combustibles also contributes to low resistivity.

Pulp and paper In the pulp and paper industry, precipitators are used on power boilers and recovery boilers. The power boiler particulate emissions requirements are the same as those for the industrial units using the same fuels. For the recovery boilers, precipitators are used to collect the residual salt cake in the flue gas. Refer to Chapter 26 for further information on the recovery boiler processes and the reuse of the collected material.

A recovery boiler is a unique application for a precipitator due to the small particulate size and the tendency for the ash to stick together. The resistivity of the particulate is low so it is collected easily in the ESP. Because the particulate is so small, gas bypass around collector plates and re-entrainment of rapped particulates in the flue gas are more of a design concern. Re-entrainment is minimized by lower gas velocities. Precipitator collection efficiencies are 99.7 to 99.8% to meet the 20% opacity and the local emissions requirements. Due to the characteristics of the salt cake particulates, a drag chain conveyor across a precipitator floor, rather than a normal hopper, is used for salt cake removal. In addition, casing corrosion is a more significant concern and as a result more insulation is required to reduce casing heat loss. Finally, in order to improve system reliability, two precipitator chambers are commonly used, each capable of handling 70% of the gas flow and each equipped with separate isolation capabilities.

Precipitators have also been applied in the steel industry to collect and recover the fine dust given off by some processes.

Performance enhancement

A change in fuel, a boiler upgrade, a change in regulation, or performance deterioration may call for a precipitator performance enhancement. Enhancement techniques include additional collection surface, gas conditioning, improved flow distribution, control upgrades and internals replacement. Gas conditioning alters resistivity by adding sulfur trioxide (SO_3), ammonia, moisture, or sodium compounds while the other modifications involve only mechanical hardware changes.

After identifying the causes of current or anticipated performance deterioration, the equipment is surveyed to determine the need for replacement or upgrade. Additional collection surface, in series or in parallel with existing surface, may be needed to meet improved particulate collection needs. Gas conditioning may be used to offset some collection surface deficiency or to enhance the performance of a marginal precipitator. Large dust accumulations near the precipitator entrance, flow patterns on the collection surface and a velocity traverse across the precipitator face indicate possible flow maldistribution. In addition, TR set controllers made before 1975 can potentially benefit from an upgrade to improve performance. Finally, a detailed internal inspection will determine a possible need for replacement of collection surface and discharge electrodes and the need to upgrade the rapping system. A combination of enhancement techniques may be needed.

Wet electrostatic precipitators

The collection of acid mists consisting of fine particulate has been accomplished with wet ESPs in some industrial processes. These units differ from the dry, or conventional, ESPs in materials; however, the collection mechanism is basically the same. Typical operation is at the flue gas moisture dew point temperature and particulate loading is low compared to normal coal-fired applications. To withstand the corrosive atmosphere, the construction materials are critical. Typical materials for the wet ESP components contacting the flue gas include:

1. Discharge system — Alloy 276
2. Collection surface — Alloy 276, lead lined, plastic
3. Enclosure — lead lined, acid brick, plastic or plastic coated

Instead of a rapping system, water spray or a water film removes the collected particulate. Most applications are small industrial units; on larger units a modularized concept is used because the configuration and shapes of the components are nonstandard compared to the dry ESP. Collection efficiencies of 99% have been reported with wet ESPs when precipitator sections or modules are placed in series.

Fabric filters

A fabric filter, or baghouse, collects the dry particulate matter as the cooled flue gas passes through the filter material. The fabric filter is comprised of a multiple compartment enclosure (Fig. 8) with each compartment containing up to several thousand long, vertically supported, small diameter fabric bags. The gas passes through the porous bag material which separates the particulate from the flue gas.

Operating fundamentals

With the typical coal-fired boiler, the particle laden flue gas leaves the boiler and air heater and enters the filter inlet plenum which in turn distributes the gas to each of the compartments for cleaning. An outlet plenum collects the cleaned flue gas from each compartment and directs it toward the induced draft fan and the stack. Inlet and outlet dampers then allow isolation of each compartment for bag cleaning and maintenance. Each compartment has a hopper for inlet gas flow as well as for particulate collection and removal by conventional equipment, as discussed further in Chapter 23. The individual bags are closed at one end and connected to a tubesheet at the other end to permit the gas to pass through the bag assembly. The layer of dust accumulating on the bag is usually referred to as the *dustcake*.

Collection of the particulate on the bag fabric is the heart of the control process. The major forces causing this collection include impingement by either direct contact or impaction and dustcake sieving. Minor forces which assist in the collection are diffusion, electrostatic forces, London-Van der Waal's forces and gravity.[6] The dustcake is formed by the accumulation of particulate on the bags over an operating period. Once formed, the dustcake and not the filter bag material provides most of the filtration. Although impingement collection is most effective on the larger particles and the sieving process collects all particle sizes, a dustcake must form to maximize overall collection.

As the dustcake builds and the flue gas pressure drop across the fabric filter increases, the bags must be cleaned. This occurs after a predetermined operating period or when the pressure drop reaches a set point. Each compartment is then sequentially cleaned to remove the excess dustcake and to reduce the pressure drop. A residual dust coating is preferred to enhance further collection.

Two fabric filter design parameters are air/cloth (A/C) ratio and drag. A/C ratio is the gas volumetric flow rate divided by the exposed bag surface area. Industry standards, along with operating experience, establish the design A/C ratios. These values are typically stated with one compartment out of service for cleaning (net condition). The pressure drop includes the drop across the bags, the dustcake and the attachment of the bag to the tubesheet. The calculation of drag for each compartment is useful in evaluating performance.

Types of fabric filters

Bag cleaning methods distinguish the types of fabric filters, with the three most common types being reverse air, shake deflate and pulse jet. The cleaning method also determines the relative size by the A/C ratio and the filtering side of the bag. Both the reverse air and the shake deflate are inside-the-bag filters with gas flow from inside the bag to outside; the pulse jet is an outside-the-bag filter with the flow from outside to inside (Fig. 9). Note that the tubesheet on the inside-bag filtering is located below the bags and for pulse jet the tubesheet is above the bags.

A reverse air, more correctly termed reverse gas, fil-

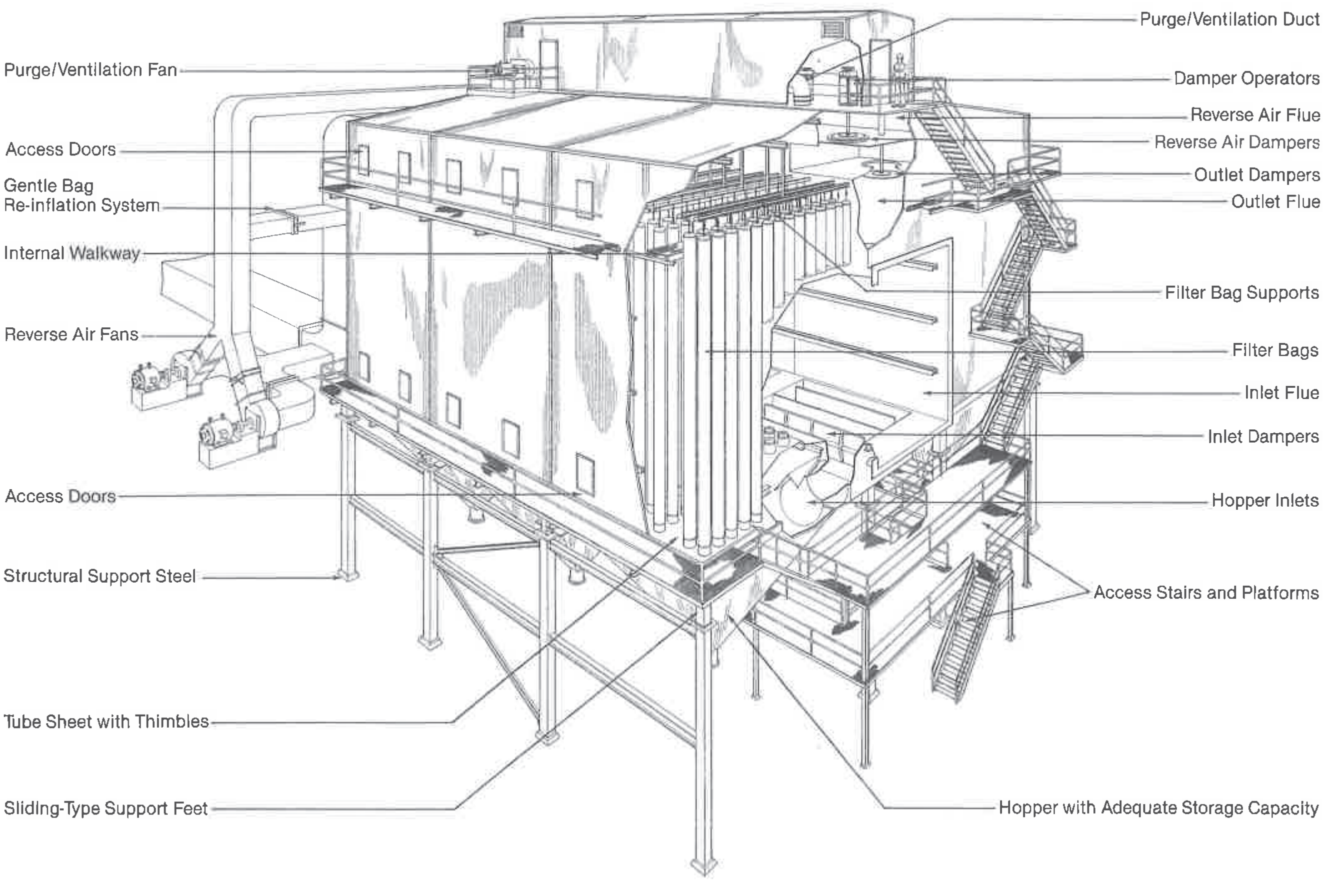


Fig. 8 Fabric filter or baghouse.

ter reverses the flow of clean gas from the outlet plenum back into the bag compartment to collapse the bags in an isolated compartment and dislodge the dustcake. This is a gentle cleaning motion. Once the dislodged particulate falls to the hopper, the bags are gently re-inflated before full gas flow is allowed for filtering. This system requires a reverse gas fan to supply the cleaning gas flow along with additional dampers for flow control. This type of filter system has been used in most large utility power plant fabric filters in the U.S. Experience with this type of fabric filter on some coal flyash applications has demonstrated that reverse gas cleaning alone does not provide an acceptable operating pressure drop. Therefore, some units have added sonic horns to each compartment to assist in the cleaning.

Shake deflate filters are similar to reverse air units in that the cleaning occurs in an isolated compartment and a small amount of cleaned flue gas is used to slightly deflate the bags. In addition, a mechanical motion is used to shake the bags and dislodge the accumulated dustcake.

Pulse jet technology is a more rigorous cleaning method and can be used when the compartment is either isolated or in service. A pulse of compressed air is directed into the bag from the open top which causes a shock wave to travel down its length dislodging the dustcake from the outside surface of the bag. A unique aspect of the pulse jet system is the use of a wire cage in each bag to keep it from collapsing during normal filtration. The bag hangs from the tubesheet. A series of parallel pulse jet pipes are located above the bags with each pipe row having a solenoid valve. This permits the bags to be pulsed clean one row at a time. The initial experience with pulse jet filters has been on industrial units, with limited use on utility units to date; however, use of pulse jet units in utility boilers is increasing.

Bag materials and supports Substantial research and development on bags and their materials has taken place to lengthen their life and to select bags for various applications. The flexing action during cleaning is the major factor affecting bag life. Bag blinding, which occurs when small particulate becomes trapped in the fabric interstices, limits bag life by causing excessive pressure drop in the flue gas. Finishes on the bag surface are also used to make some bags more acid resistant and to improve cleaning.

The most common bag material in coal-fired utility units with reverse fabric filters is woven fiberglass. Typical bag size is 12 in. (305 mm) diameter with a length of 30 to 36 ft (9.1 to 11.0 m). Bag life of three to five years is common. The shake deflate filters also use mostly fiberglass bags. On both of these units the fiberglass bag is fastened at the bottom to a thimble in the tubesheet. At the top, a metal cap is sown into the bag and the bag has a spring loaded support for the reverse air filters. The upper operating temperature limit is 500F (260C) for most fiberglass bags.

In addition to fiberglass, the industrial size filters use synthetic materials with trade names like Nomex®, Ryton®, Gortex® and Hyglass®. Advantages of the synthetic materials include better abrasion resistance and

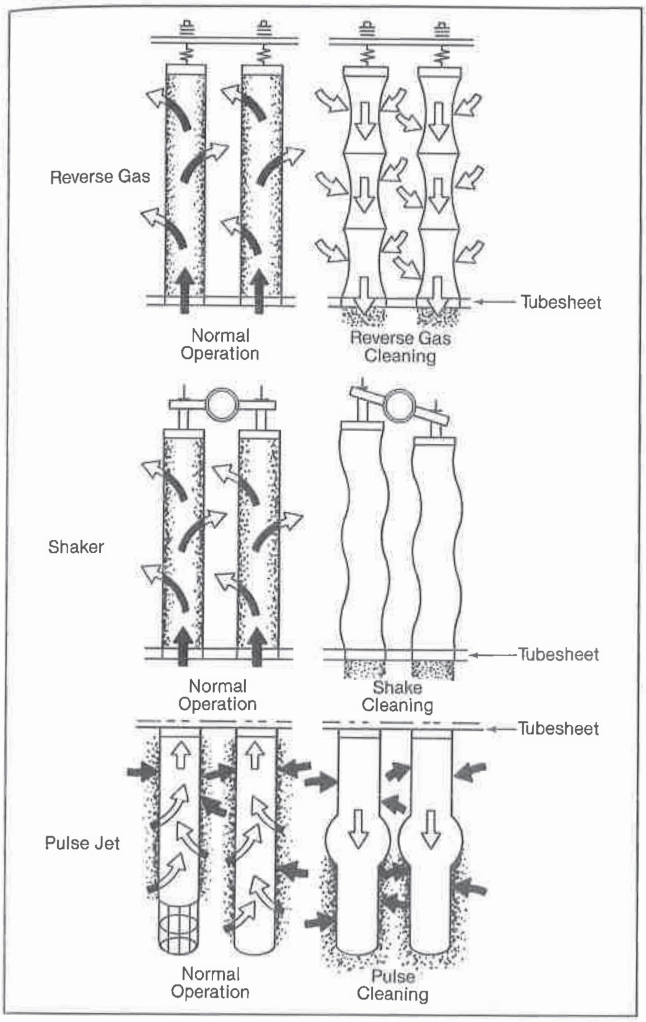


Fig. 9 Fabric filter types.

resistance to acid attack. Disadvantages include higher cost and limited temperature capabilities. For the pulse jet filters, the typical bag size is 5 or 6 in. (130 or 150 mm) diameter with a length of 10 to 20 ft (3 to 6 m).

Enclosure The fabric filter is a metal encased structure with individual bag compartments. The inlet and outlet plenums are typically located between two rows of compartments to provide short inlet and outlet flue connections. This enclosure rests on a support steel structure. For reverse air units, interior access is required at both the lower tubesheet and bag support elevations. In a pulse jet filter, access is required above the tubesheet for bag cage removal. This is provided by large roof access doors or by a top plenum and a side manway. Typical enclosure materials are carbon steel ASTM A-36 or equivalent under normal coal-fired boiler conditions. The entire enclosure is covered with insulation and lagging to keep metal temperatures high and to minimize corrosion potential.

Hoppers Each filter compartment has a hopper to collect the dislodged particulate and to channel its flow to the ash removal system. Most filters also use the hopper as part of the flue gas inlet to each compartment. Therefore, the hopper is designed with steep sides for ash removal along with considerations for proper gas flow distribution. Hopper heaters, level detectors, poke holes and an access door are common hopper features.

Performance and applications

The first utility fabric filter in the U.S. was installed with Babcock & Wilcox's participation on an oil-fired Southern California boiler in the mid 1960s.[7] After a few years of limited activity, several utilities had installed fabric filters by the late 1970s. Interest in these systems continues to grow due to the high particulate removal efficiency. They are the preferred collector for some applications. Well designed filters routinely achieve greater than 99.9% particulate removal, meeting all U.S. EPA and local regulations.

Besides the utility coal-fired applications, fabric filters are used on circulating fluidized-bed boilers, industrial pulverized and stoker coal units, refuse-fired units in combination with a dry flue gas scrubber, and in the steel industry. A unique advantage with fabric filters in this application is that all of the flue gas passes through the dustcake as it is cleaned; when the dustcake has high alkalinity, it can be used to remove other flue gas constituents and acid gases, such as sulfur dioxide (SO_2). (See Chapter 35.)

Mechanical collectors

Mechanical dust collectors, often called cyclones or multiclones, have been used extensively to separate large particles from a flue gas stream. The cyclonic flow of gas within the collector and the centrifugal force on the particulate drive the particulate out of the flue gas (Fig. 10). Hoppers below the cyclones collect the particulate and feed an ash removal system. The mechanical collector is most effective on particles larger than 10 microns. For smaller particles, the collection efficiency drops considerably below 90%.

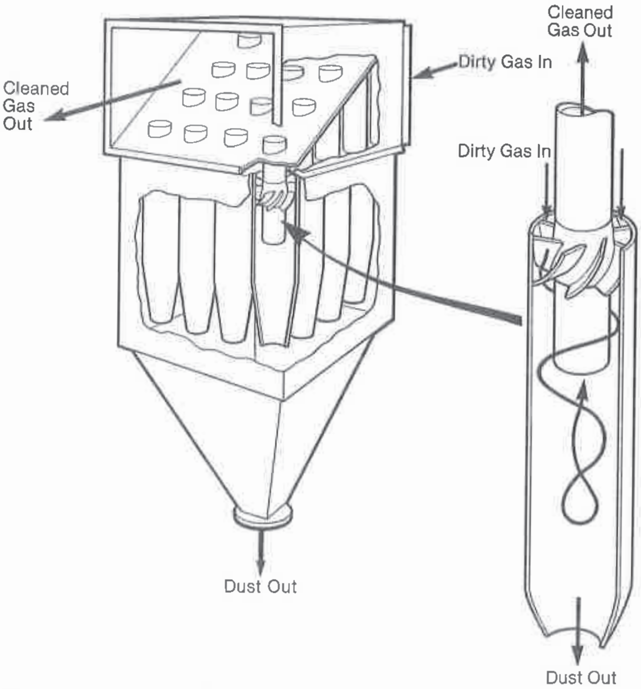


Fig. 10 Mechanical collector.

Mechanical collectors were adequate when the emissions regulations were less stringent and when popular firing techniques produced larger particles. These collectors were frequently used for re-injection to improve unit efficiency on stoker firing of coal and biomass. With stricter emissions regulations, mechanical collectors can no longer be used as the primary control device. However, with the onset of fluidized-bed boilers, there has been a resurgence of mechanical collectors for recirculating the bed material. A high efficiency collector is then used in series with the mechanical one to meet particulate emissions requirements. (See Chapters 16 and 29 for more information on fluidized-bed combustion.)

Wet scrubbers

A wet scrubber can be used to collect particulate from a flue gas stream with the intimate contact between a gas stream and the scrubber liquid. The venturi-type wet scrubber (Fig. 11) is used to transfer the suspended particulate from the gas to the liquid. Collection efficiency, dust particle size and gas pressure drop are closely related in the operation of a wet scrubber. The required operating pressure drop varies inversely with the dust particle size for a given collection efficiency; or, for a given dust particle size, collection efficiency increases as operating pressure drop increases.

Due to the excessive pressure drop and the stringent particulate regulations, wet scrubbers are used infrequently as the primary collection device. However, on most coal-fired applications, wet scrubbers are required in series with a high efficiency collector for control of acid gas emissions, so the extra particulate removal is an added benefit.

Other collection devices

Other more specialized particulate control devices include ELECTROSCRUBBER® filters and ceramic tube filters. The ELECTROSCRUBBER® filter combines the technologies of granular filtration and electrostatic collection and uses electrostatic forces on the particulate as the flue gas passes through a recirculating bed of gravel. Charged particles attach to the gravel which is cleaned as the lower bed gravel is recirculated to the top of the bed. The collected dust is sent to disposal and the cleaned gas stream flows to the stack. This collection device is popular on wood-fired units because it aids fire prevention by its handling of glowing embers.

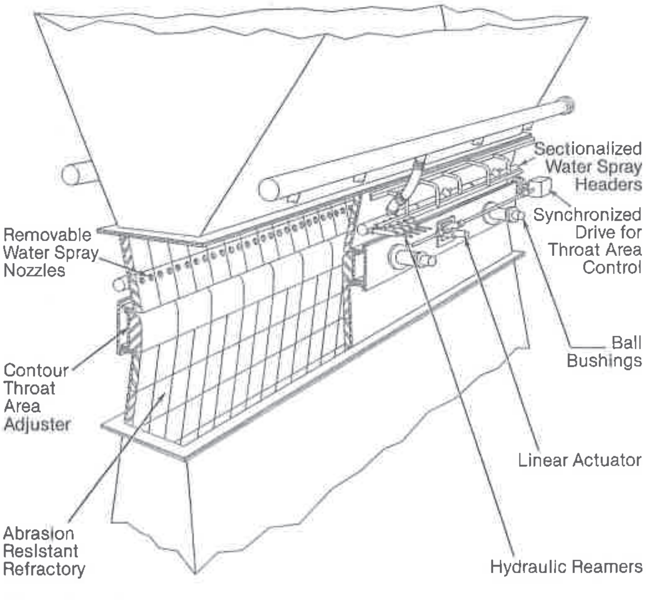


Fig. 11 Venturi-type wet scrubber.

Ceramic tube filters are being developed for high temperature and pressure applications such as coal gasifiers and pressurized fluidized-beds. (See Chapters 17 and 29.)

Equipment selection

Major evaluation factors to consider when selecting particulate control equipment include emissions requirements, boiler operating conditions with resulting particulate quantity and sizing, allowable pressure drop/power consumption, combined pollution control requirements, capital cost, operating cost and maintenance cost. For new units which must meet the stringent federal, state and local regulations, the selection is reduced to a comparison of electrostatic precipitators and fabric filters because these are the only high efficiency, high reliability choices. For retrofits on operating units, the performance of existing control equipment as well as unique flue gas conditions may require specialized equipment.

The advantages of a well designed ESP are high total collection efficiency, high reliability, low flue gas pressure loss, resistance to moisture and temperature upsets, and low maintenance. Advantages of a fabric filter include high collection efficiency throughout the particle size range, high reliability, resistance to flow upsets, little impact of ash chemical constituents on performance, and good dustcake characteristics for combination with dry acid gas removal equipment. A comparison of overall and particle size collection efficiencies for precipitators and fabric filters is shown in Fig. 5. An application where small particulate dominates would favor a fabric filter for maximum control as long as bag blinding does not occur.

For those applications where an ESP or fabric filter is technically acceptable and high collection efficiencies are required, some general guidelines on capital costs are: 1) on small units, a pulse jet fabric filter is more economical, 2) on large units with medium or high sulfur coal, an ESP is economical, and 3) on low sulfur coal-fired large units, a reverse air fabric filter may be more economical. However, when operating and maintenance costs are also considered, the lowest capital cost may not provide the lowest overall cost. Therefore, it is important to perform a detailed engineering study to quantify all of the variables for a specific site to obtain a true assessment of the real cost.

International particulate control

Particulate control regulations and control equipment usage have been emphasized in Western Europe, Scandinavia, South Africa, Australia, Japan and Canada, as well as the U.S. The traditional high efficiency collection device in all countries has been the ESP for many applications; however, the fabric filter has gained acceptance in Australia and the U.S. for coal-fired units. On new refuse-fired units, the combination of spray dryer and fabric filter is popular in Scandinavia, Western Europe and the U.S.

Control challenges for the future

Particulate control will be required for steam generation combustion equipment as long as ash bearing fuels are used. New combustion methods may change the ash characteristics, permitting less costly or more efficient control equipment. Furthermore, new material developments, increased use of electronics and overall equipment size reduction are expected to continue.

References

1. White, H.J., *Industrial Electrostatic Precipitation*, Addison-Wesley, Reading, Massachusetts, 1963.

2. United States Code of Federal Regulations, Title 40, Part 60, Subparts D, Da, Db and Dc, July 1988.

3. Federal Register, Environmental Protection Agency, 40 CFR Part 60, Vol. 55, No. 177, September 12, 1990.

4. Lane, W.R., and Khosla, A., "Comparison of baghouse and electrostatic precipitator fine particulate, trace element and total emissions," ASME-IEEE Joint Power Conference, Indianapolis, Indiana, September 27, 1983.

5. *Gas Flow Model Studies*, Publication EP-7, Industrial Gas Cleaning Institute, January 1987.

6. Bustard, C.J., *et al.*, *Fabric Filters for the Electric Utility Industry*, Vol. 1, Report CS-5161, Electric Power Research Institute, Palo Alto, California, 1988.

7. Bagwell, F.A., Cox, L.F., and Pirsh, E.A., *Design and Operating Experience With a Filterhouse Installed on an Oil-Fired Boiler*, Air Pollution Control Association, June 1968.

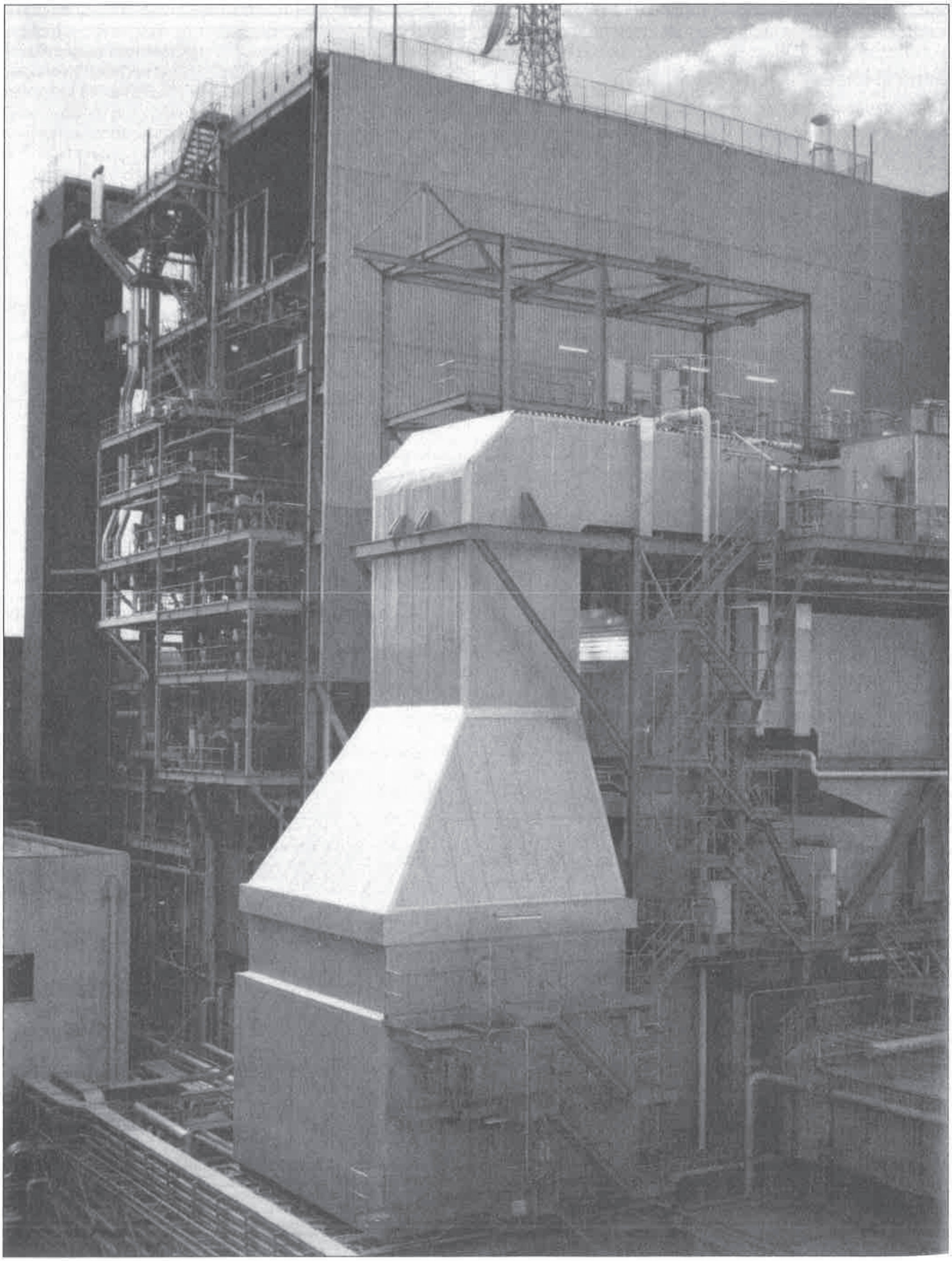
Bibliography

Bickelhaupt, R.E., "A technique for predicting flyash resistivity," Report EPA-600/7-79-204, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, July 1979.

Billings, C.E., *et al.*, *Handbook of Fabric Filter Technology*, GCA Corporation, Bedford, Massachusetts, December 1970.

Faulkner, M.G., and DuBand, J.L., "A mathematical model of electrostatic precipitation (Rev. 3)," Report EPA-600/7-84-069, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, July 1984.

Katz, J., *The Art of Electrostatic Precipitator*, Precipitator Technology, Inc., Munhall, Pennsylvania, 1981.



Selective catalytic reduction (SCR) NO_x emission control system retrofit on a coal-fired boiler.

Chapter 34
Nitrogen Oxides Control

Nitrogen oxides (NO_x) are one of the primary pollutants emitted during combustion processes, with transportation systems accounting for the largest contribution in the United States. (See Fig. 1.) Along with sulfur oxides (SO_x) and particulate matter, NO_x emissions have been identified as contributors to acid rain and ozone formation, visibility degradation and human health concerns. As a result, NO_x emissions from most combustion sources are regulated and require some level of control as discussed in Chapter 32. A number of approaches can be used to control NO_x emissions.

NO_x formation mechanisms

NO_x refers to the cumulative emissions of nitric oxide (NO), nitrogen dioxide (NO_2) and trace quantities of other species generated during combustion. Combustion of any fossil fuel generates some level of NO_x due to high temperatures and the availability of oxygen and nitrogen from both the air and fuel.

NO_x emissions from fired processes are typically 90 to 95% NO with the balance being NO_2. However, once the flue gas leaves the stack, the bulk of the NO is eventually oxidized in the atmosphere to NO_2. It is the NO_2 in the flue gas which creates the brownish plume often seen in a power plant stack discharge. Once in the atmosphere, the NO_2 is involved in a series of reactions which form secondary pollutants. The NO_2 can react with sunlight and hydrocarbon radicals to produce photochemical (urban) smog and acid rain constituents.

There are two common mechanisms of NO_x formation, thermal NO_x and fuel NO_x.

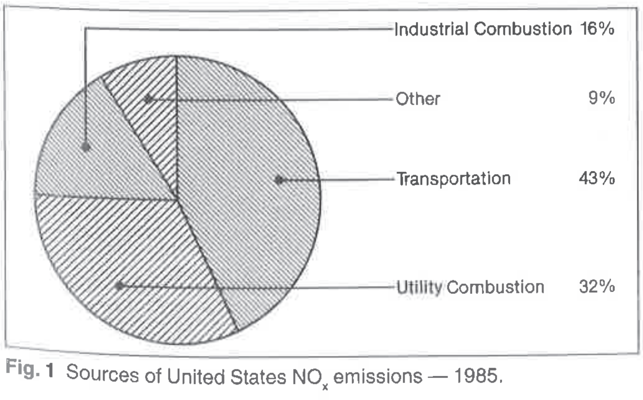


Fig. 1 Sources of United States NO_x emissions — 1985.

Thermal NO_x

Thermal NO_x refers to the NO_x formed through high temperature oxidation of the nitrogen found in the combustion air. The formation rate is a strong function of temperature as well as the residence time at temperature. Significant levels of NO_x are usually formed above 2200F (1204C) under oxidizing conditions with exponential increases as the temperature is increased. At these high temperatures, molecular nitrogen (N_2) and oxygen (O_2) in the combustion air dissociate into their atomic states and participate in a series of reactions. One product of these reactions is NO. The three principal reactions proposed for this process are:[1,2]

$$N_2 + O \rightarrow NO + N \qquad (1)$$

$$N + O_2 \rightarrow NO + O \qquad (2)$$

$$N + OH \rightarrow NO + H \qquad (3)$$

The traditional factors leading to complete combustion (high temperatures, long residence time and high turbulence or mixing) all tend to increase the rate of thermal NO_x formation. Therefore, some compromise between effective combustion and controlled NO_x formation is needed.

Thermal NO_x formation is typically controlled by reducing the peak and average flame temperatures. This can be accomplished through a number of combustion system changes. Controlled mixing burners can be used to reduce the turbulence in the near burner region of the flame and to slow the combustion process. This typically reduces the flame temperature by removing additional energy from the flame before the highest temperature is reached. A second approach is staged combustion where only part of the combustion air is initially added to burn the fuel. The fuel is only partially oxidized and then cooled before the remaining air is added separately to complete the combustion process. A third alternative is to mix some of the flue gas with the combustion air at the burner, referred to as flue gas recirculation. This increases the gas weight which must be heated by the chemical energy in the fuel, thereby reducing the flame temperature.

These technologies have been used effectively with gas, oil and coal firing to reduce NO_x formation. Specific use of each technology or a combination of technologies depends upon the costs, fuel and regulatory requirements. The specific applications of these different combustion