

# Assessment of Factors Affecting Boiler Tube Lifetime in Waste- Fired Steam Generators: New Opportunities for Research and Technology Development

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1617 Cole Boulevard  
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A national laboratory of the U.S. Department of Energy  
Managed by Midwest Research Institute  
for the U.S. Department of Energy  
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**Final Report**

**on**

**Assessment of Factors Affecting Boiler Tube Lifetime  
in Waste-Fired Steam Generators:**

**New Opportunities for Research and  
Technology Development**

**to**

**ASME**

**April 1994**

**by**

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## 1. Summary

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This study was conducted to assess the overall significance of the major factors that affect boiler tube lifetime—corrosion and erosion problems—in waste-fired steam generators, and to identify the research needs and technology development opportunities that could have the greatest impact on the metal wastage problem. The study was conducted by compiling data for specific facilities from the open literature and from available reports, which were then supplemented by soliciting information on operating experience and corrosion/erosion problems encountered from owners, operators, and manufacturers. In addition, the state of understanding of the applicable mechanisms of corrosion in waste-fired boilers was developed from the literature, and from expert experience.

A major difficulty was encountered in the data collection activity because the major manufacturers, owners, and operators consider fireside problems to be part of the competitive edge in this business and, as a result, specific and general information on the type, location, frequency, and cost of corrosion tends to be considered proprietary. Smaller organizations do not always have useful records, since they do not have the means to retain the expertise required to diagnose and develop details or to document corrosion problems and determine the root causes. The best available information indicates that the operational record of modern waste-to-energy (WTE) units is good, but that there are occasional unexpected outages, and that the major fireside problems usually are handled during scheduled outages. While there is some documentation in the open literature, it is incomplete because the basic cause of the major failure is not fully understood and the corrective actions to remedy or prevent the failure are not completely reported.

There are 92 waste-to-energy (WTE) facilities in operation in the U.S. with a capacity of 200 tons per day or greater, and 24 facilities are in the planning stages. Sixty-five percent of these new plants will be privately owned, and 35 percent will be municipality-owned; all will be privately operated. For economic reasons, there is a desire to improve plant efficiency, which will require raising the steam pressure and temperature. Seventeen new plants will be built at steam temperatures exceeding 400°C (750°F), which was previously considered a threshold limit for controlling corrosion. However, continued expansion will require implementation of all the design and operating improvements available, as well as a full understanding of the corrosion mechanisms, so that major corrosion problems that were experienced in the early stages of development of such plants in Europe can be avoided.

The minimum cost of an outage to handle a manageable corrosion problem is estimated to range from \$15K to \$19K (not including the cost of materials) or \$0.36 to \$0.45 per ton of waste processed (not including the cost of materials). This cost compares with an average operating and maintenance cost of \$33.58 per ton of waste processed. Therefore, the cost of not understanding the real causes of the corrosion problems may be equivalent to at least 1.1 percent of the operating and maintenance costs.

The basic causes of reduction in boiler tube lifetime in waste combustors are well known in general terms: they are the presence of chlorine, alkali, and heavy metals in the fuel that combine to produce low-melting, highly-corrosive deposits on the tubes, and the heterogeneous nature of the fuel that makes it difficult to handle and results in hard to control combustion conditions. In practice, corrosion in WTE plants is primarily associated with the fact that the fuel is very heterogeneous, and gives rise to severe problems in maintaining the uniform combustion conditions desired in a steam boiler. The poor combustion characteristics of the fuel result in regions of incomplete combustion, which may include localized reducing conditions (high CO levels), high heat flux from flame impingement, and possibly the presence of aggressive species and deposits. The fuel also introduces chlorine-containing compounds, alkali metal compounds [especially sodium (Na) and potassium (K)], and heavy metals such as lead (Pb), tin (Sn), and zinc (Zn), all of which may combine in the flame to form potential corrodants. Low-melting point chlorides of these metals, or mixtures of chlorides, deposited on the heat transfer surfaces remove protective oxide scale from the tube surfaces, allowing rapid dissolution into the molten salts, or rapid oxidation. Solid chloride deposits also can cause corrosion in the presence of sulfur dioxide in the combustion gas. Although sulfates form in deposits on tube surfaces, they typically have melting points above the temperatures that are encountered on the heat transfer surfaces in current WTE plants, and so are not particularly corrosive. Corrosion occurs on furnace walls at metal temperatures in excess of 232°C (450°F), under constant or cycling reducing conditions. These surfaces also are vulnerable to corrosion when in contact with combustion gas at temperatures in excess of 954°C (1750°F).

To avoid corrosion in the furnace zone, the design and operation of the combustion zone should be optimized so that combustion of the fuel is completed in the lower furnace. Significant improvements often can be gained through relocation or redirection of overfire air ports to improve turbulence and minimize gas stratification. Since the nature of the fuel precludes complete control of

the combustion process, the lower furnace wall should be protected by silicon carbide tiles, or the tube surfaces should be protected by a Ni Cr alloy applied as a cladding or as a weld overlay, up to a height at which the gas temperature has fallen to 954°C (1750°F), or less. Above this level, carbon steel tubes are expected to give satisfactory life, and sufficient surface should be available to cool the gas to 760°C (1400°F) or less, before it enters the convection bank.

Molten chloride deposits are not expected in the convective tube bank, but can occur in conditions where combustion is not completed in the lower furnace. Where combustion is relatively uniform and is completed before the gas exits the radiant zone, the deposits in the convective zone are expected to be predominantly silicates or sulfates with relatively high melting points. Reducing conditions need not exist in the convective zone for corrosion to occur: the convective heat transfer surfaces also are vulnerable to attack by chlorine (HCl) present in the gas phase. The apparent role of HCl is to compromise the protective nature of the oxide scale by causing cracking or porosity, thereby increasing the oxidation rate. Until recently, the maximum steam temperature in WTE units was limited to 400°C (750°F) to control corrosion. A strategy for minimizing the potential for corrosion with higher steam temperatures is to arrange the steam flow so that the tubes carrying the highest temperature steam are exposed to the lowest temperature flue gas.

Where alloys with increased corrosion resistance are required, Alloy 625 and Alloy 825 appear to offer the best high-temperature service life for furnace wall and superheat applications, respectively.

The convective heat transfer surfaces could be cleaned by mechanical rapping to prevent fouling which has the claimed advantage over soot blowing that it removes only deposits and not protective oxide scale, and does not cause localized erosion. The tubes should be vertically oriented to facilitate removal of deposits, and the tube bundle configuration should be sufficiently robust to allow high-intensity rapping. For modern WTE plant designs which incorporate the features described, experience with convection sections producing steam at 443 to 454°C (830 to 850°F) is satisfactory.

There is a need to verify and apply the available knowledge of fundamental corrosion mechanisms to operating plants. There also is a need to accurately document and diagnose boiler tube failures to be certain of their origin (fuel, operation, or design), to be certain that proper measures are taken to correct them, and to ensure that they do not become misleading evidence for future design and operating decisions. A helpful approach in the short term should be directed to a means for in situ monitoring to detect high-temperature furnace exit temperatures (or other parameters), to avoid

subjecting the convective pass to a corrosive environment, and to understanding the conditions that cause accelerated corrosion immediately above Si C linings and high-alloy overlays on the upper furnace wall. In addition, research is needed to identify the alloying requirements for improved corrosion resistance to the specific conditions experienced at the furnace wall and in the convection zone, which will benefit not only materials selection for current units but also indicate the requirements for higher-temperature operation. Increasing the outlet steam temperature also is the goal of a program being conducted by the New Energy Development Organization (NEDO) in Japan; that program is actively developing high alloys for use in the final stages of the superheaters. Such alloys with improved corrosion resistance could be used to increase the tube lifetimes in current boiler designs, provided they prove cost-effective.

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## 2. Introduction

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The disposal of municipal solid waste (MSW) is a major problem in numerous communities in the United States. In this country, approximately 195.7 million tons of MSW were produced in 1990 (EPA, 1992), of which 17 percent was recovered for recycling or composting, 16 percent was combusted, and about 67 percent was disposed of in landfills. In major urban areas, space may either be no longer available or the cost of land is rapidly increasing. Nevertheless, in some parts of the country modern landfill permits are being awarded, so that landfills continue to be an available option for the foreseeable future.

Landfill design and construction emphasizes containment of the wastes to protect public health and many improvements have come about in recent years. A modern landfill is well lined to contain liquid. Liquid that may be contained is frequently pumped out and treated for safe disposal. Methane gas created in the landfill is also frequently collected by a system of wells. The gas may be burned in air using a torch-like device called a flare. More than 212 landfills use the collected gas to generate energy. The energy is usually electricity generated and used on-site. Some landfill gas is cleaned to make pipe line quality gas.

Combustion of waste can reduce the volume of material requiring disposal by about 90 percent. In addition, combustion of MSW can result in the generation of significant amounts of energy; the net generation capacity of all currently operating plants in the U. S. is 2,962 MWe (Berenyi and Gould, 1993). Reduction in availability of local landfill sites may increasingly focus attention on alternative means for MSW disposal, so that there is potential for the capacity for combustion of MSW in the U. S. to grow in the future. Nevertheless, decisions concerning the disposal of MSW by landfill or by combustion will be based on the relative costs of the available options, which will involve the haulage, tipping, maintenance, and monitoring costs (possibly offset by income from gas recovery) associated with landfill use, compared with the haulage, tipping, plant maintenance, pollution control, and ash disposal costs (offset by revenue from electricity and steam sales) associated with combustion.

Waste combustion has been practiced for more than thirty years in Germany, and experience there has formed the basis for the practices adopted elsewhere. Combustion of waste in Germany

increased rapidly from 1965 through 1987 (Reichel, 1989); in 1987 there were 47 plants burning approximately 9 million tons/year of refuse, and it was projected that in 1995, approximately 67 plants would be in operation burning about 12 million tons/year. Based on 1980 figures, about 28 percent of the refuse in Germany was burned, compared to 23 percent for the European Economic Community, 65 percent for Japan, and 10 percent for the U.S. Of these refuse combustion plants in Germany, 27.4 percent were practicing heat recovery, and that heat recovery represented 0.46 percent of the total energy consumption in Germany (Reichel, 1989).

In 1993, there were approximately 92 waste-to-energy (WTE) facilities with capacities of 200 tons/day or greater in operation in the United States, capable of processing 96,227 tons/day of municipal waste (Berenyi and Gould, 1993). The existing waste combustion facilities in the U.S. tend to be more numerous on the East Coast (37.4 percent of the total), where land availability is increasingly limited. However, of the 24 facilities that are in the planning stages, 44.4 percent are in the south.

The four principal types of combustor used for the combustion of MSW are categorized by the EPA as:

- (1) Mass-burn systems, in which the waste is combusted without any pre-processing other than the removal of items too large to navigate the feed system. Refuse is typically placed on a grate that moves the waste through the combustor. Combustion air in excess of stoichiometric amounts is supplied both from below the grates and above the grates. Such combustors vary in size from 50 to 1000 tons per day of refuse throughput per unit, and often use multiple combustors to achieve high site capacities. The largest mass burn combustion facility in the U.S. has a capacity of 3,150 tons per day (using 3 units). The major features of a modern mass-burn unit are illustrated schematically in Figure 6.1
- (2) Modular mass-burn combustors, in which the waste is usually burned without pre-processing, often in a staged-combustion process. Combustion air at sub-stoichiometric levels is supplied to a primary chamber, and the incompletely-combusted products that pass into the secondary chamber are then mixed with excess air to complete the combustion process. This mode of operation successfully minimizes both the particle and

toxic gas emission from these units. Modular combustors are typically made in a size range from 5 to 150 tons per day of refuse throughput.

- (3) Rotary, mass-burn combustors, in which unprocessed waste is combusted in a refractory-lined rotary kiln, which replaces the grate. This design is intended to provide sufficient mixing and residence time to achieve complete burnout of the fuel before the flue gas leaves the kiln and passes through the heat recovery sections of the boiler. The capacity of these combustors is in the range 100 to 450 tons per day; the average total capacity of the 8 facilities operating in the U.S. is 871 tons per day.
- (4) Refuse-derived fuel (RDF) systems, in which MSW that has been processed to various extents is burned. RDF processing typically includes some sorting and removal of components that can be recycled (such as metals, glass, paper) or which have no heating value (stones, gravel), so that the calorific value of RDF typically is 20 percent or so higher than that of unprocessed waste. In addition, the waste is shredded, and subjected to mechanical and air-classification, so that the size of the fuel fed to the boiler is smaller and more uniform than unprocessed MSW. RDF may be burned as the sole fuel, or co-fired with other fuels, such as coal. The largest RDF combustion facility in the U.S. has a capacity of 4,000 tons per day (using 3 units) The type of combustor usually employed is based on stoker-fired coal-fueled boilers; an example of the design of a modern RDF-fired boiler is illustrated in Figure 6.3.

In 1993, some 73 percent (74 facilities of capacity >200 tons/day) of the U.S. waste combustion capacity was mass-burn units, while RDF facilities represented 27 percent of capacity (19 facilities, including 3 fluidized-bed combustors). Of the mass burn facilities, 8 employed rotary combustors, and 12 employed modular combustors, these two types accounting for about 15 percent of the capacity of the mass burn facilities. Also, some 24 dedicated waste-firing units with capacities of greater than 200 tons per day were planned or under construction, representing about 26,673 tons/day capacity and 672 MWe net generation capacity.

In boilers combusting MSW or RDF, corrosion, slagging, or fouling problems can occur. Numerous incidents of corrosion and erosion-corrosion of waterwall tubes, superheater tubes, and other pressure parts have been reported. The major causes of serious high-temperature corrosion in refuse-fired boilers are the presence in the fuel of chlorine-containing species and metallic species capable of forming low-melting point chloride compounds. Corrosion results from either gas-phase attack by HCl (and  $\text{Cl}_2$  formed beneath boiler-tube deposits), or by molten salt attack by metal chlorides and their eutectic mixtures that melt at temperatures in the same ranges as those typical of the boiler metal surfaces. Corrosion by sulfur-containing species also is possible in boilers.

In contrast, furnace wall corrosion in coal-fired boilers usually involves sulfur species, and takes the form of direct gas-phase corrosion by  $\text{H}_2\text{S}$  of water walls that experience exposure to conditions of incomplete combustion, or by pyrosulfates from complex deposits. Molten salt corrosion of the superheater tubes can occur which involves complex alkaline-iron sulfates formed beneath deposits. Because the root-cause mechanisms of these various forms of attack in coal-fired boilers are reasonably well understood, a methodology for identifying, recording, and selecting permanent solutions has been devised and implemented by a number of power companies. As a result, the availability loss of the participating boilers has dropped to 1.7 percent (with the best units reporting 1.4 percent), compared to previous experience of 2.7 percent (Dooley, 1992). The two major ways in which the implementation of this methodology has been effective have been the virtual elimination of repeat failures, and an increase in the accuracy with which failure types, and causes, have been identified by maintenance engineers.

Sulfur-related corrosion also can occur in refuse-fired boilers. However, because of the high levels in refuse-derived fuels of species capable of forming low-melting point sulfates and chlorides, additional sources of corrosion not encountered in coal-fired boilers often are present in refuse-fired boilers. Factors which accelerate these corrosion processes are tube wall temperatures exceeding  $350^\circ\text{C}$  ( $662^\circ\text{F}$ ), and large quantities of vaporized chlorides reaching the tubes. Corrosion in refuse-fired units may also be aggravated by erosion from soot blowing, particularly when steam is used as the soot blowing medium, since erosion by liquid droplets can occur. Soot blowing can remove the existing scale and deposit, thus stripping the tube of a potential barrier to the corrosive action and exposing fresh metal to attack at higher rates.

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### 3. Sources of Information and Methodology Used

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The data used in this report were compiled from a comprehensive search of the technical literature, conference proceedings, and technical reports, and from discussions with representatives of boilers manufacturers, owners, and operators of waste-fired boilers. The data collection activities were coordinated with similar activities for a project conducted for the Electric Power Research Institute (Wright, et al., 1994), which was aimed at determining the types of boiler tube failures experienced in WTE units. A questionnaire was developed to guide data collection; a copy is presented in Appendix A. Questionnaires were completed to the extent possible using data gathered from the literature or from other available sources, and then approaches were made to the operators, owners, or designers in an attempt to complete the picture. Units were targeted that had reported corrosion problems, or that were known to have experienced failures. In addition, individuals were contacted who were actively involved in committees of technical societies, such as the ASME, that had interest in all aspects of waste combustion; other sources were individuals involved in the examination of tube failures, who were identified from published articles and from prior contacts. A summary of the information obtained in this way concerning the factors affecting boiler tube lifetime in WTE boilers is shown in Table A.1.

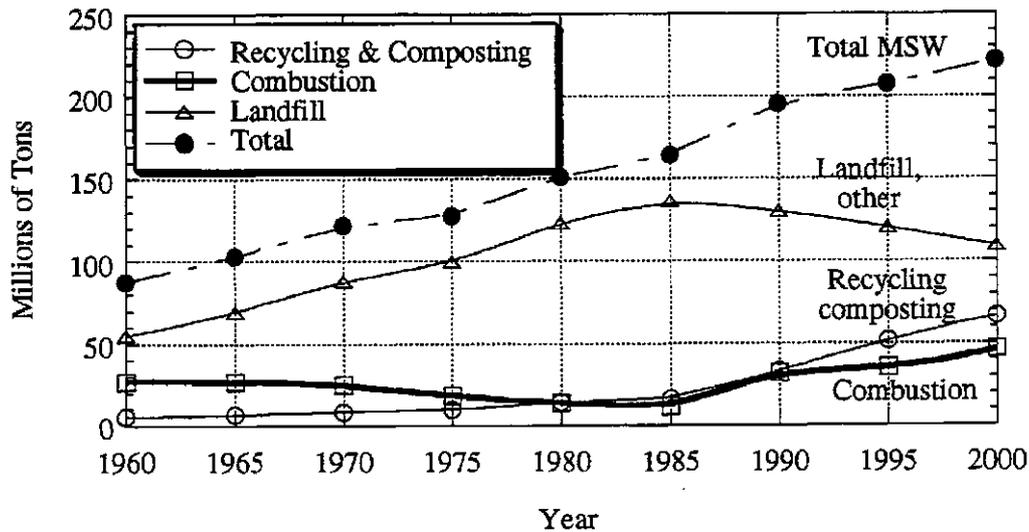
The basic technical information gathered from all sources for all of the operating combustors in the U.S., is shown in Table B.1 in Appendix B, and lists details of the type of unit, its developer, owner, and operator, together with the equipment manufacturers, the waste capacity and steam and power production specifications. Also listed in Table B.1 are the citations in the main reference section that deal with a specific unit. Information on MSW combustors planned in the U.S. is included in Appendix B, Table B.2, to the extent that it was available.

Information that was concerned with actual operating conditions, with economic aspects of operation and, in some cases, with specific materials problems and the solutions used was considered to be proprietary by some manufacturers. In fact, no information at all was available from some manufacturers and, in those cases, we were unable to supplement the available published data. There is, at present, no centralized repository of information or expertise in the areas of interest to this

program, so that the data collection process often involved a different approach for each organization considered.

## 4. Trends in Waste-Derived Fuel

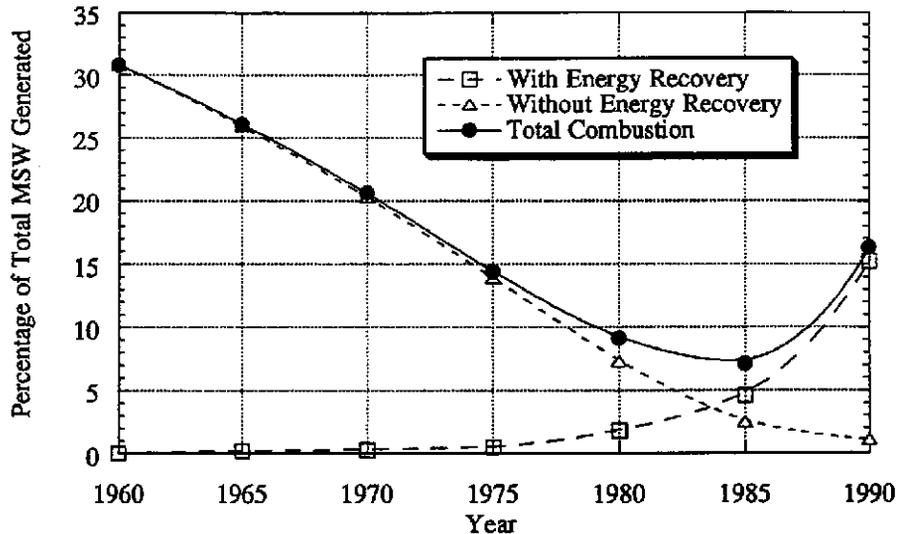
The amount of MSW generated in the U.S. has increased at a steady rate from approximately 90 million tons in 1960 to approximately 196 million tons in 1990, and is expected to reach 225 million tons by the year 2000 (EPA, 1992). This trend is illustrated in Figure 4.1, which also compares the amounts of MSW disposed of in landfills, by collection for recycling and composting, and by combustion.



**Figure 4.1 Trends in the disposal of MSW in the U.S. (EPA, 1992).**

In 1960, an estimated 31 percent of the MSW in the U.S. was disposed of by combustion, mostly with no energy recovery (and no air pollution controls). In the 1960's and 1970's, combustion of MSW dropped steadily as old incinerators were shut down, reaching a minimum of 7 percent in 1985, as is shown in Figure 4.2. In recent years, the combustion of MSW has increased steadily, reaching 16 percent in 1992. All of the major new facilities are designed for energy recovery, and to meet air pollution standards. Based on surveys of new MSW combustors that are scheduled to come

into operation in the 1990's, the U.S. Environmental Protection Agency (EPA, 1992) projected that the percentage of the MSW combusted will increase to 21 percent by the year 2000.



**Figure 4.2 Trends in combustion of MSW in the U.S. (U.S. EPA, 1992).**

The EPA also reported that, in 1990, the throughput in refuse-fired boilers over a year of operation was, on average, approximately 80 percent of rated capacity. New facilities are reporting operation at very high utilization rates, whereas older combustors do not meet the same levels of annual throughput compared to rated capacity.

The types of materials that are discarded into the U.S. MSW stream are indicated in Figure 4.3, as a function of time (Anon, 1988). These estimates were made in 1988; comparison of the data for the year 1990 from two sources indicate good agreement, except for paper products and cardboard for which the two estimates disagreed by 4.2 percent, as illustrated in Table 4.1.

Using known heat values of each constituent, an ash content of 22.4 percent and a moisture content of 25.2 percent, a calorific value for the actual 1990 MSW of 4,860 Btu/lb was obtained (Herrmann, 1991). This is close to the value of 5,000 Btu/lb currently used for planning purposes by the major MSW combustor suppliers. On a dry basis (29.5 percent ash), the calorific value is 6,500 Btu/lb.

Taking the average composition shown in the right hand column in Table 4.1 (Franklin Associates, Ltd., 1988) as the baseline, the effects of removal of various proportions of the components

under various recycling scenarios was examined. The amounts of the MSW involved in these scenarios are as shown in Table 4.2.

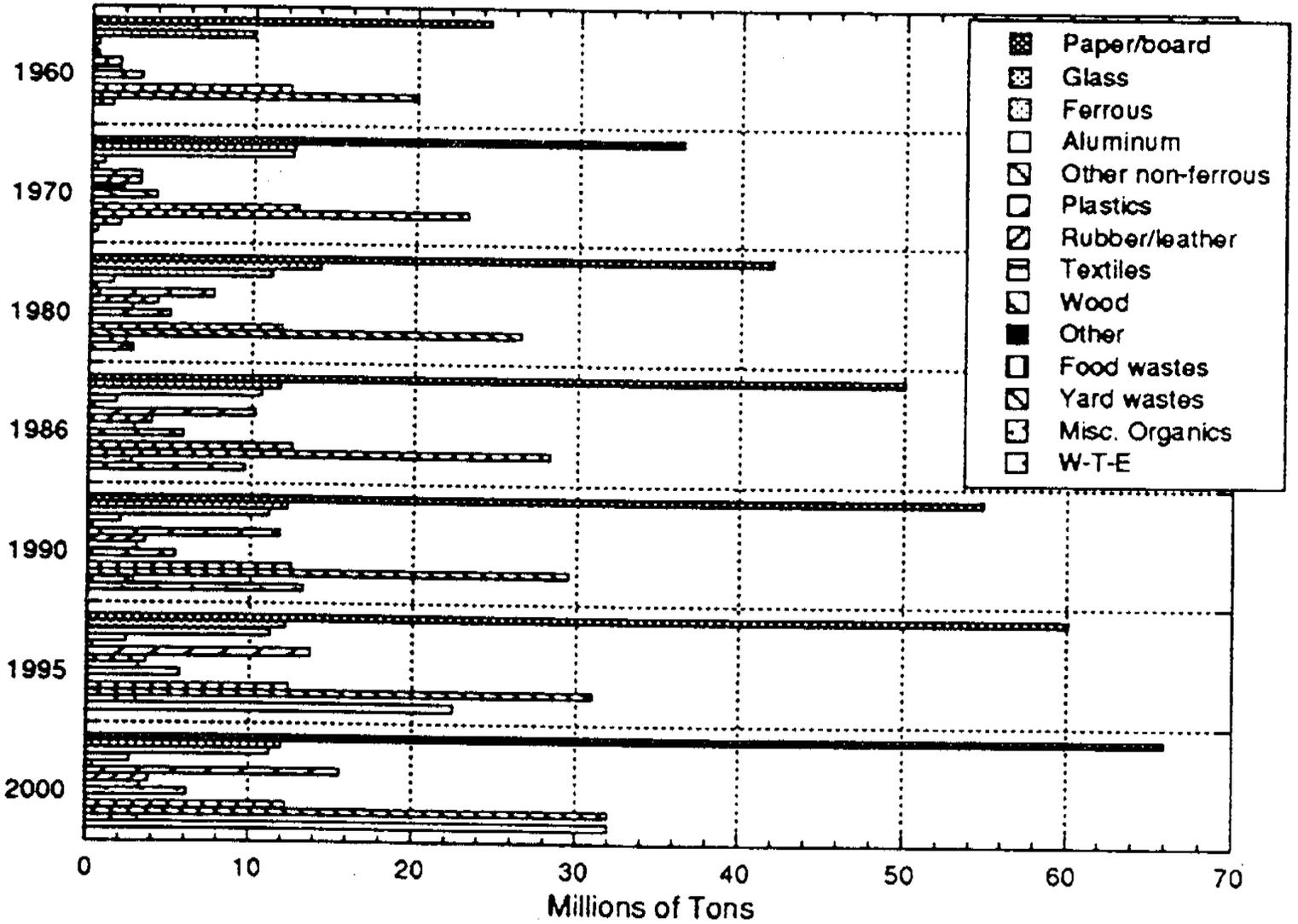


Figure 4.3 Types of materials discarded into U.S. MSW stream (1988 estimate).

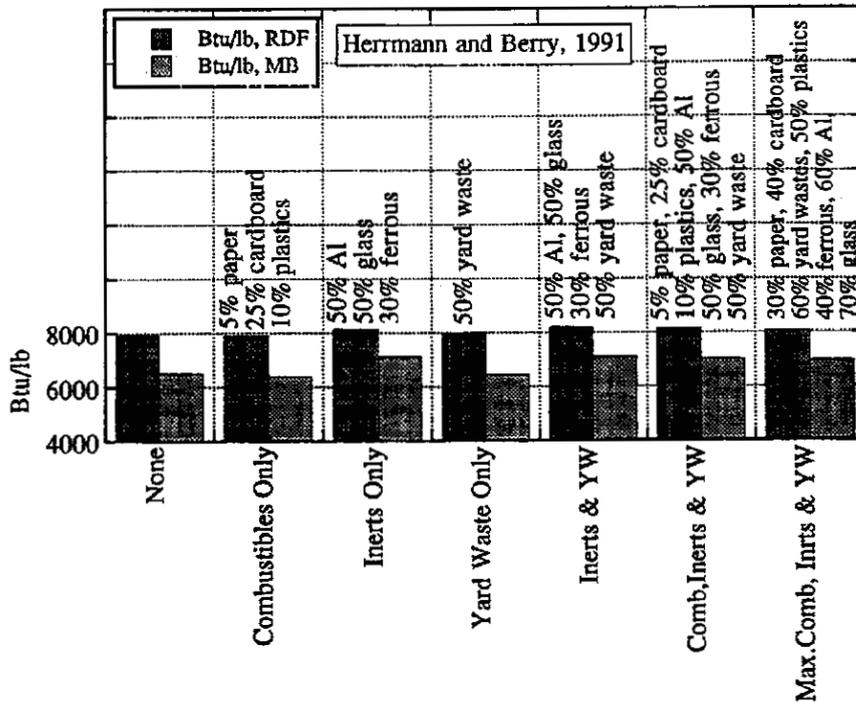
Table 4.1 Makeup of U.S. municipal solid waste.

Component	% of MSW (EPA, 1992)	% of MSW (Anon, 1988)
Paper products		30.0
Cardboard	36.8 (total)	11.0
Yard waste	19.7	17.9
Plastics	7.9	6.5
Food, rubber, textile, wood	16.3	16.0
Ferrous metal	7.5	6.8
Aluminum	1.3	1.2
Other non-ferrous metal	0.2	0.7
Glass	8.3	8.2
Stone, ceramics		0.6
1/4 in. fines	2.0 (total)	1.1

Table 4.2 Levels of components removed in assumed recycling scenarios.

Component Recycled	Wt.% of MSW Recycled	Components Removed (wt.%)
(a) Combustibles only	4.9	5% of paper, 25% of cardboard, 10% of plastics
(b) Inerts only	6.7	50% of Al, 50% of glass, 30% of ferrous metal
(c) Yard waste only	9.0	50% of yard waste
(d) Inerts and yard waste	15.7	(b) + (c)
(e) Combustibles, inerts, & yard waste	20.6	(a) + (b) + (c)
(f) Maximum combustibles, inerts, & yard waste	36.6	30% of paper, 40% of cardboard, 60% of yard wastes, 50% of plastics, 40% of ferrous metal, 60% of Al, 70% of glass

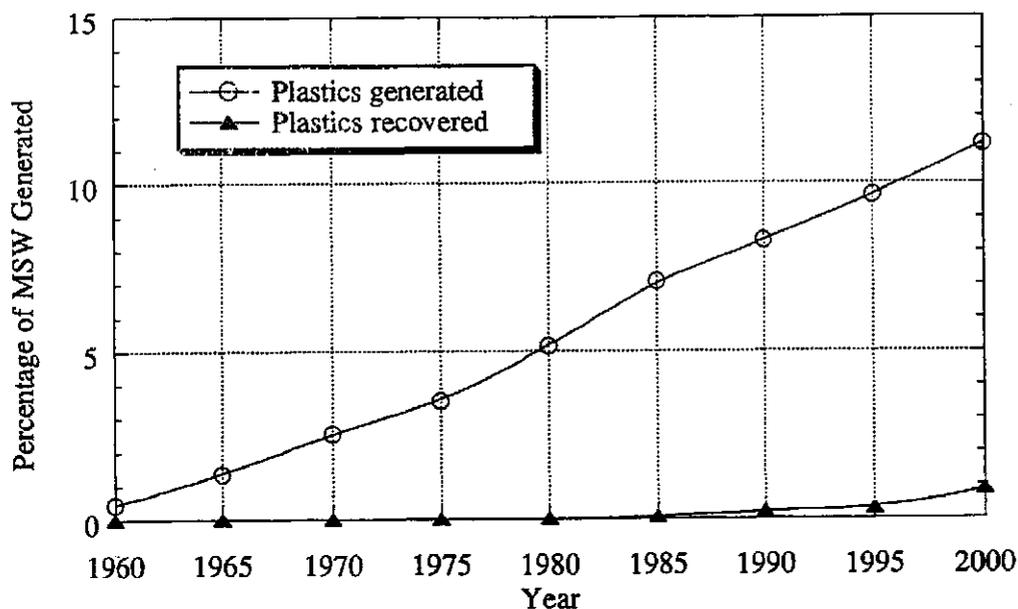
Some of the results of these considerations are illustrated in Figure 4.4 for both MSW and RDF. In this figure, the calorific values of the MSW after recycling has removed the stated components is represented by the bars labelled 'MB', or mass burn, whereas the bars labelled 'RDF' indicate the calorific value of RDF made from the same MSW stream. Recycling 4.9 percent of the MSW in the form of combustibles, for example, resulted in a reduction in calorific value of the MSW and RDF of only 1.7 and 0.5 percent, respectively. Perhaps surprisingly, the maximum change in the calorific value of MSW was an increase from 6,500 to 7,100 Btu/lb, which suggests that the effects on the thermal design aspects of MSW combustors of any of the recycling schemes suggested will be relatively small. The maximum changes in calorific value of RDF from the various recycling scenarios were even smaller, from 7,920 to 8,160 Btu/lb (dry basis).



**Figure 4.4 Effects of recycling of various components of the waste stream on the calorific value of MSW and RDF.**

The plastics content of MSW in the U.S. has increased rapidly since 1960, when it comprised less than 1 percent ( $0.4 \times 10^6$  tons), to 8.3 percent ( $16.2 \times 10^6$  tons) in 1990, and is projected to

increase to  $24.8 \times 10^6$  tons (> 11 percent) in the year 2000, as is indicated in Figure 4.5 (EPA, 1992). Plastics are found in containers and packaging, in durable and in non-durable goods.



**Figure 4.5 Trend in plastics content of U.S. MSW (EPA, 1992).**

The amounts of plastics in MSW from the various sources are itemized (for 1990) in Figure 4.6. Packaging contains plastics in the form of beverage and condiment containers, bags and sacks, wrapping, and other products. In durable goods, plastics are found in appliances, household furnishings such as furniture, carpets, and in items such as the cases of lead-acid batteries, and other products. In non-durable goods, plastics are found in eating utensils, clothing, disposable diapers, and miscellaneous products.

Vaughan, et al. (1974) estimated that PVC accounted for approximately 24 percent of the plastics in MSW. Using this value, and the chlorine content of PVC (57.7 wt. percent), the chlorine content of MSW derived from PVC can be estimated as indicated in Figure 4.7. Also incorporated in the data used in that figure are values for the chlorine content derived from the actual total U.S. production of PVC in 1991 [ $9.16 \times 10^9$  lb (Reisch, 1992)] and 1992 [ $9.99 \times 10^9$  lb (Reisch, 1993)]. It is evident that the curve suggests that the PVC-derived chlorine content of plastics in MSW will approach 1.6 percent by the year 2000.

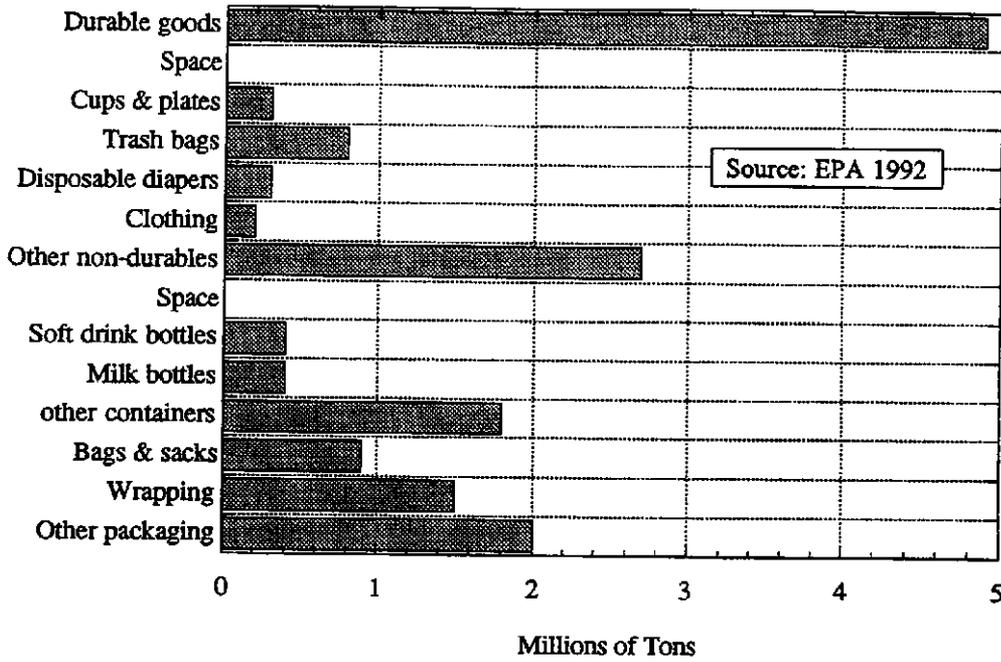


Figure 4.6 Sources of plastics in the U.S. MSW stream in 1990 (EPA, 1992).

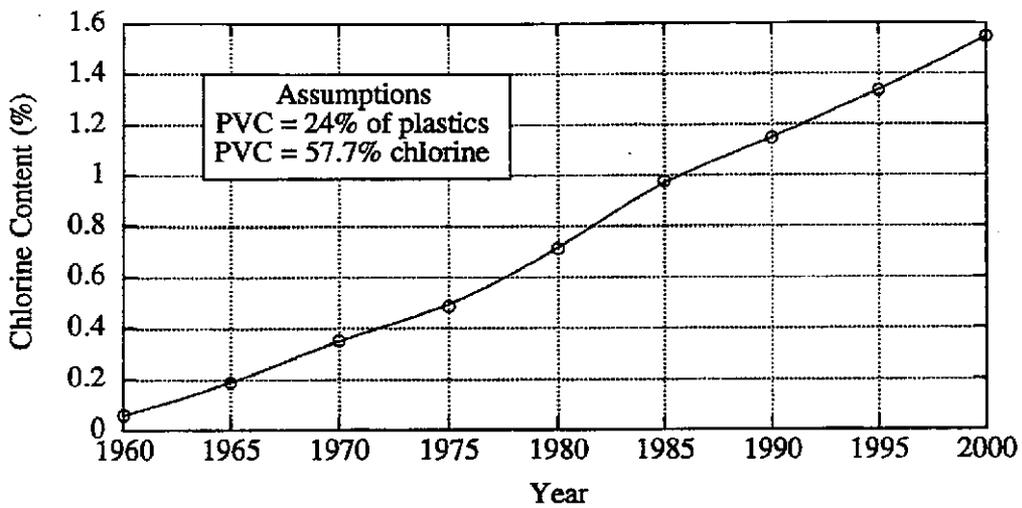


Figure 4.7 Estimated PVC-derived chlorine content of U.S. MSW.

Overall, it appears that the amount of MSW generated will continue to increase at a rate of approximately three million tons per year for the foreseeable future. In the event that the decreased trend of disposal in landfills continues, combustion will represent an increasingly important option. The projected effects of increased recycling of components in the waste on the calorific value of the fuel are relatively small; it is unlikely that the combustion characteristics will be improved as a result of recycling procedures, but any increased removal of items such as glass and aluminum could help to improve the operability of the combustor grates. If the removal of heavy metals such as lead, tin, and zinc could be improved along with the glass, some of the potential for forming corrosive, low-melting compounds might be reduced. The possibility of removing and recycling a significant fraction of the plastics could lead to some reduction in the chlorine content of the waste. The chlorine derived from PVC is projected to increase at a steady rate of approximately 0.4 percent every 10 years. However, since the other sources of chlorine in the waste are diverse, it may not be viable to reduce chlorine levels via recycling to a point where corrosion is reduced significantly.

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## 5. Summary of Current Understanding of the Causes of Metal Wastage in MSW Combustors

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Corrosion in refuse-fired boilers is caused primarily by interaction among chlorine, alkali metals (Na and K), and by heavy metals such as Pb, Sn and Zn from the fuel. Attack can result from the action of low-melting chlorides deposited on the tube surfaces, and from gas-phase corrosion, and the type and rate of corrosion can be greatly increased under conditions of incomplete combustion. Where the flue gas is persistently sub-stoichiometric<sup>1</sup> (reducing), that is, contains high levels of C O, the sulfur may be present predominantly as H<sub>2</sub>S. Measurements by Johnson, et al. (1970), albeit in a propane/liquefied petroleum gas flame, showed a rapid increase in H<sub>2</sub>S and COS in the flame, and a decrease in SO<sub>2</sub> and SO<sub>3</sub> levels as the equivalence ratio (ratio of actual combustion air level to that required for stoichiometric combustion) fell below about 0.8. Sulfur may play an important role by promoting chlorine corrosion and by acting directly as H<sub>2</sub>S under reducing conditions.

### 5.1 Occurrence of Corrosive Species in Refuse.

The chlorine in municipal refuse is of both organic and inorganic origin. Polyvinyl chloride (PVC) plastics are the principal source of the organic portion. The U.S. production of PVC amounted to  $9.99 \times 10^9$  lb. in 1992 (Reisch, 1993), and a significant amount of this material finds its way into the waste stream each year. Sorting of bulk refuse at four different times at a municipal combustor (Vaughan, et al., 1974) gave values for the plastics content of the refuse of 3 to 6 percent. Of this, about 24 percent was estimated to be PVC. Eight analyses of typical refuse samples from the combustor showed that the chlorine content of the waste, on a dry basis, ranged from 0.32 to 0.79 weight percent, with an average of 0.49 percent. The remaining chlorine in the waste was determined to be of inorganic origin, present primarily as NaCl.

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<sup>1</sup> Stoichiometric is defined as the relative amount of compounds required for a completion of a chemical reaction. In combustion systems stoichiometric conditions refer to the amount of oxygen required to complete the conversion process. Therefore substoichiometric is a condition where insufficient oxygen exists for complete combustion.

Shredded refuse samples on 5 different days at the Baltimore County, MD facility contained 0.41 to 0.61 weight percent chlorine. Similar testing of bulk refuse at the Greenpoint combustor, Brooklyn, NY gave values ranging from 0.63 to 2.06 weight percent chlorine. Large amounts of plastic and food products in the waste during the sampling time were responsible for the very high chlorine content in Brooklyn wastes (Domalski, 1986).

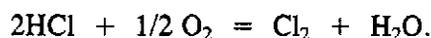
Sulfur is present in municipal refuse in materials such as rubber (sulfur cross links), detergents (sulfonates), paper products ( $\text{Na}_2\text{SO}_4$ ), and occasionally as gypsum board ( $\text{CaSO}_4 \cdot 6\text{H}_2\text{O}$ ). Vaughan, et al., (1974) reported analyses for sulfur in refuse, which gave values ranging from 0.1 to 0.4 percent, with an average of 0.2 percent.

## 5.2 Behavior of Corrosive Species During Combustion.

Probably the most extensive work on the behavior of chlorine during combustion in boilers is the work of the Central Electricity Generating Board relating to high-chlorine British coals. However, the composition and combustion properties of coal are significantly different from those of MSW or RDF, so that ash formation and deposit behavior, hence, the predominant mechanisms of corrosion, are quite different in coal-fired boilers than in WTE units. Nevertheless, the general reactions in the flame are expected to be similar. Because it is associated with organic matter, chlorine appears in the combustion products primarily as HCl. Gibb (1983) indicated that the amount of HCl found in boiler flue gases was about 80 ppm for each 0.1 percent of chlorine in the coal. Since the combustion temperature in MSW-fired units easily exceeds that at which chlorine evolution occurs, the same rule can be applied to refuse. Other measurements in the furnace of a 120 MWe boiler fired with coals containing high-chlorine contents (Clarke and Morris, 1983) indicated HCl values ranging from 150 to 470 ppm, close to those calculated on the assumption that all the coal chlorine was converted to HCl in the flame.

Analyses of the bottom ash and fly ash from refuse-firing by Vaughan, et al. (1974), showed that only 0.01 to 0.02 weight percent chlorine remained in the ash. Hence, it appears that practically all of the chlorine in refuse also is volatilized during combustion.

Some of the HCl in the combustion products can be oxidized to elemental Cl<sub>2</sub> in the presence of metal oxide catalysts, which would be possible on the surfaces of oxidized tubes or beneath boiler deposits, by the classic Deacon reaction:



Chlorine can even be formed in the flame, as demonstrated by Mal'tseva, et al., (1983), who showed that several percent of Cl<sub>2</sub> were formed when organic compounds containing chlorine were burned.

In the flame, the majority of the sulfur is oxidized to SO<sub>2</sub>, and a proportion is further oxidized to SO<sub>3</sub>, the reaction being promoted in the presence of catalytically-active surfaces such as those on oxidized tubes. The maximum amount of SO<sub>3</sub> that can be formed from the oxidation of SO<sub>2</sub> is dependent mainly on temperature. The equilibrium level of SO<sub>3</sub> increases as the temperature decreases: below 427°C (800°F), essentially all the sulfur in the system SO<sub>2</sub>-SO<sub>3</sub> will be SO<sub>3</sub> at equilibrium whereas, above 1093°C (2000°F), it will be mainly SO<sub>2</sub>. These equilibrium values also are affected by the oxygen partial pressure such that very low oxygen partial pressures will lead to a smaller conversion to SO<sub>3</sub>. In boilers, however, equilibrium is rarely attained in the flame, so that the levels of SO<sub>3</sub> formed are typically lower than predicted, and only about 1 percent of the SO<sub>2</sub> is converted to SO<sub>3</sub>.

Not all the chlorine and sulfur appear in the flame as HCl or SO<sub>2</sub> when Na also is present. From thermodynamic data, Boll and Patel (1961) calculated relationships between the various Na-compounds that could exist in boiler flue gases. The results for a high-chlorine (0.66 percent), 4.5 percent sulfur coal are shown in Figure 5.1. It is significant that NaCl predominates under reducing conditions (90 percent theoretical air) and at very high temperatures, whereas Na<sub>2</sub>SO<sub>4</sub> has the highest vapor pressures under oxidizing conditions and lower temperatures.

In view of such data and from a knowledge of the composition of deposits formed in coal-fired boilers, Jackson (1963) deduced a series of reactions that probably occur in the flue gas and in deposits at various temperatures. As shown in Figure 5.2, chlorides participated throughout the deposit in the case of a high-chlorine fuel, whereas chlorides were converted to hydroxides for a low-chlorine fuel. This conversion would result in formation of HCl as well:



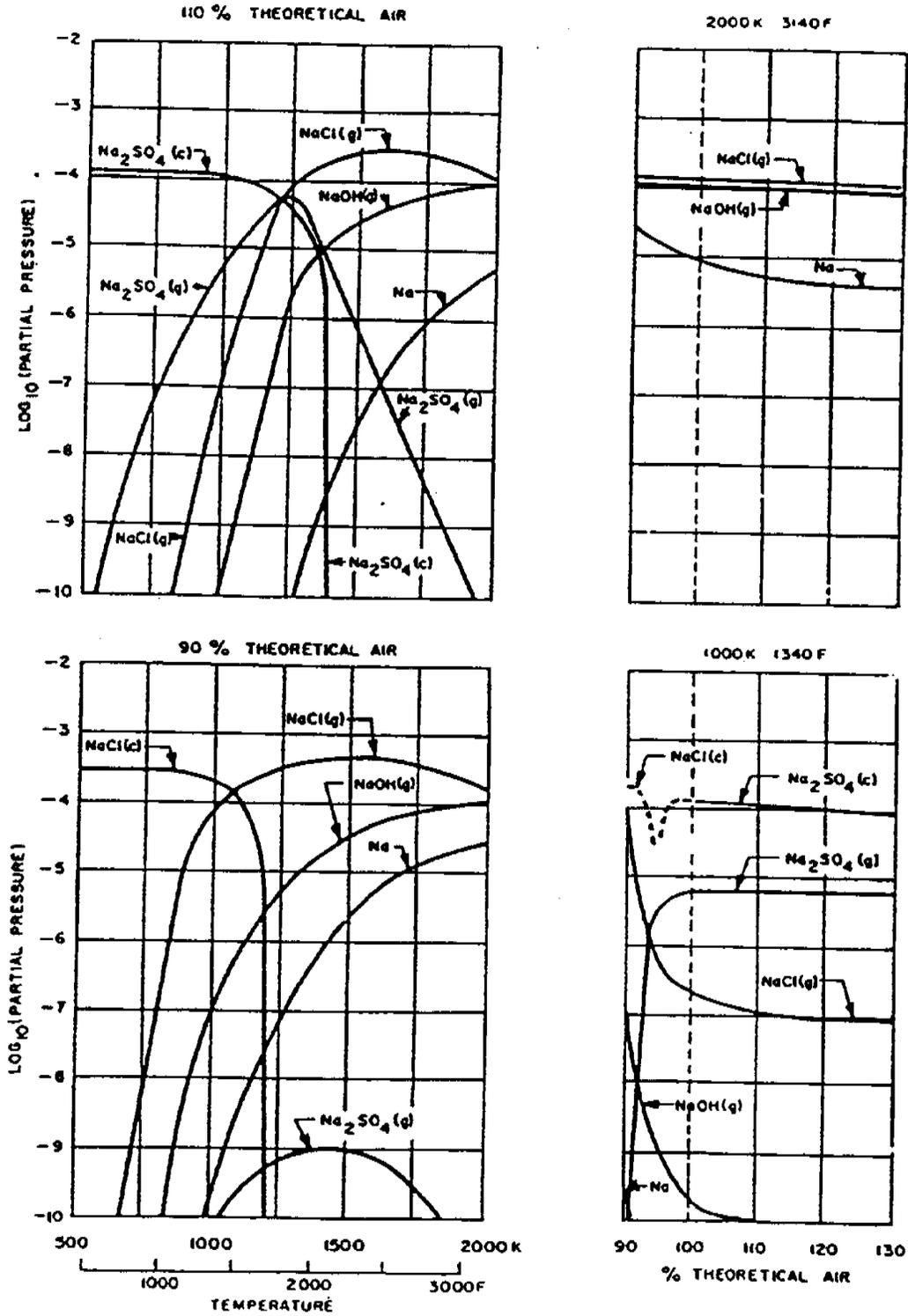


Figure 5.1. Calculated partial pressures of sodium compounds under combustion conditions (Boll & Patel, 1961)

Cutler, et al., (1971) calculated that, at equilibrium in the flue gases of a boiler fired with coal containing 0.8 weight percent chlorine at 1627°C (2960°F) flame temperature, 25 percent conversion to NaOH would take place. However, the extent of conversion would decrease to 10 percent at 1227°C (2240°F) and 5 percent 1027°C (1880°F).

Bishop (1968) identified NaCl by X-ray diffraction in the fly ash deposited downstream of the flame from combustion of a British (Thoresby) coal, containing 0.86 to 0.90 percent chlorine and 0.9 percent sulfur, in a combustion rig which simulated superheater tube conditions. The initial deposits, formed during the first hour, contained 10 to 25 percent chloride. As the exposure time increased, the NaCl was converted to an equivalent amount of Na<sub>2</sub>SO<sub>4</sub>, and the chlorine content of the deposit leveled off at about 5 percent after 3 hours. These results, showing the decrease in chlorine accompanied by the increase in sulfur content, are shown in Figure 5.3. Bishop also found that the critical metal temperature for NaCl deposition was 730°C (1346°F). Above this temperature no NaCl was found in the deposits.

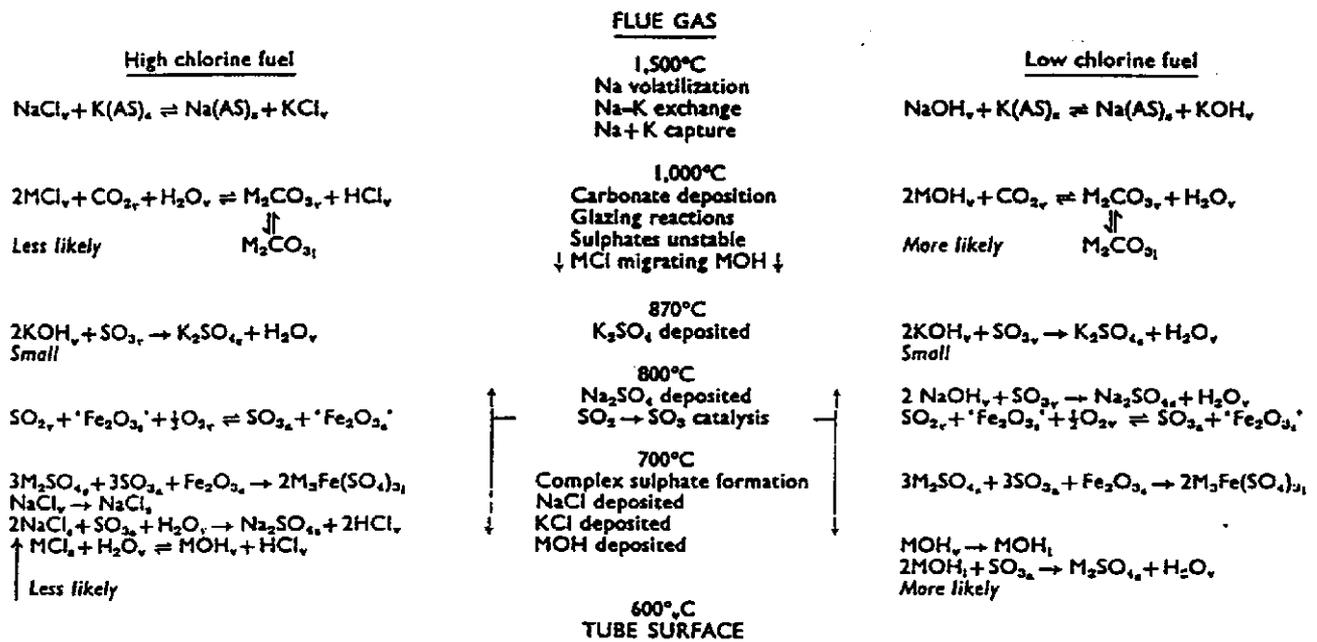
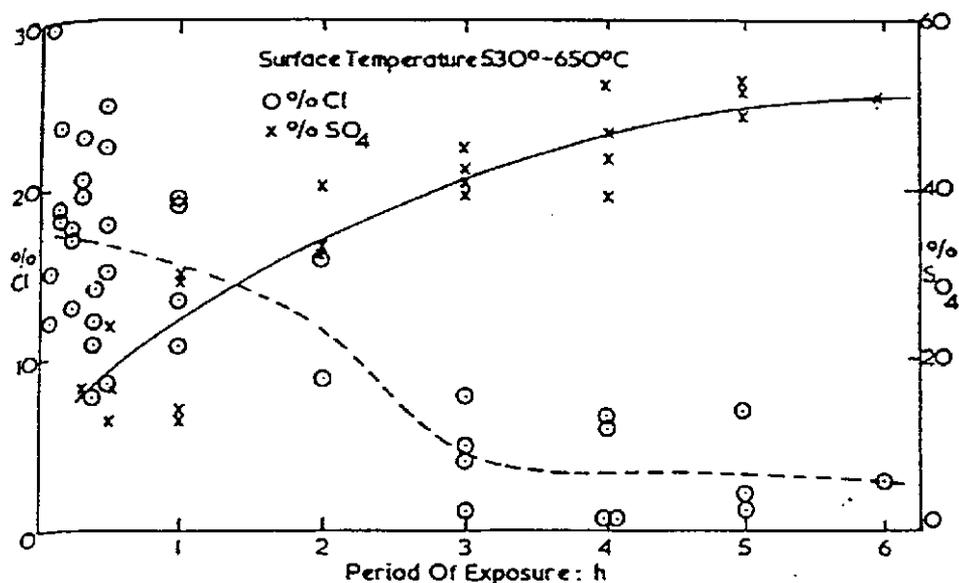


Figure 5.2 Sequence of reactions with temperature gradient in deposit. (AS) - aluminosilicate. Subscripts: a = adsorbed, 1 = liquid, s = solid, v = vapor (Jackson, 1963).

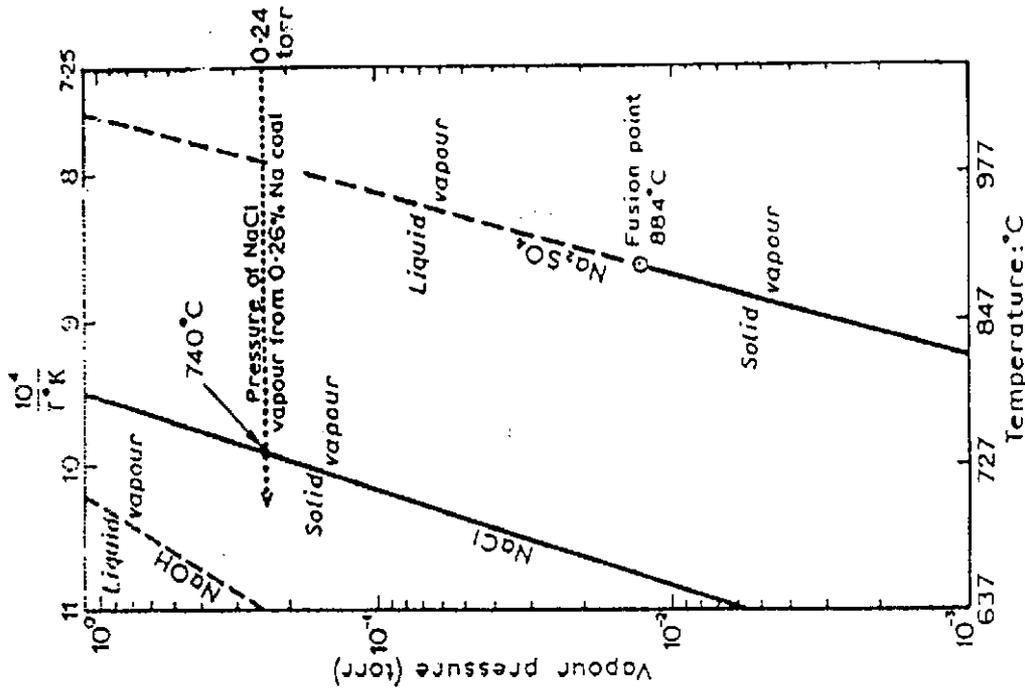


**Figure 5.3 Chlorine and sulfate content of deposits from burning a high-chlorine coal (Bishop, 1968).**

Both NaCl and KCl were identified by X-ray diffraction analysis of probe deposits collected at the Miami County, OH waste combustor (Krause, 1986). These chlorides were found on the lower temperature probe specimens, exposed at about 260°C (500°F) and, in some short-term tests (24-hour), chloride concentrations of 21 to 27 weight percent were measured.

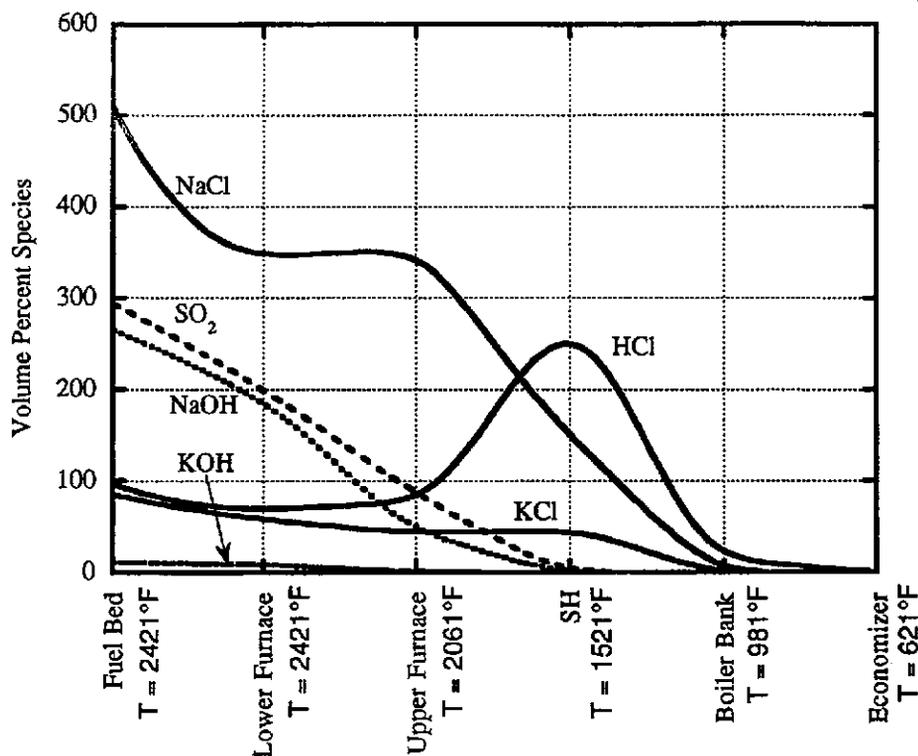
The transport of NaCl downstream of a flame also was investigated by Jackson and Duffin (1963), using a combustion rig that provided flue gas temperatures, composition, and residence time approximating that of a full-scale plant. When NaCl was added to the fuel, it was possible to condense it onto cooled probes and, by varying the temperature of the collecting surface, vapor pressure data were obtained. The maximum metal temperature for NaCl deposition of about 732°C (1350°F) noted by Bishop was confirmed in this work. The vapor pressure plot for NaCl in the presence of water vapor is shown with those for NaOH and Na<sub>2</sub>SO<sub>4</sub> in Figure 5.4. Under combustion conditions, the maximum partial pressure of NaCl vapor which could be obtained from the coal used would be 0.24 torr. This corresponds to the NaCl vapor pressure at a temperature of 740°C (1364°F), which is in agreement with Bishop's results.

Daniel (1991) estimated the chemical compositions of the flue gas and deposits on the furnace wall and superheaters from the combustion of a refuse-derived fuel containing 0.62 percent chlorine,



**Figure 5.4 Vapor pressures of NaOH, NaCl, and Na<sub>2</sub>SO<sub>4</sub> under combustion conditions (Jackson and Duffin, 1963).**

0.29 percent sulfur together with, in weight percent, 1.08 Na; 0.77 K; 3.88 Ca; 0.28 Mg; 0.77 Fe; 6.40 Si; 0.72 Al; 0.05 Pb and 0.02 Zn. The concentration of the chlorine, sulfur, and alkali species in the flue gas as it passes through the boiler are illustrated in Figure 5.5. In the furnace and superheater regions, the calculated (equilibrium) concentrations of HCl (70 to 270 ppm) and SO<sub>2</sub> (90 to 300 ppm) were in good agreement with values measured in refuse-burners. Beyond the superheater, as the flue gas is cooled below about 527°C (981°F), the reaction between HCl and alkali silicates is thermodynamically favored, and the calculated HCl concentration generally approached zero. In practice, because these gas-solid reactions generally are slow at the lower temperatures, most of the chlorine remains in the flue gas as HCl, and there is little chloride (as NaCl or KCl) in the fly ash. At the concentrations present in the flue gas, NaCl, NaOH, KCl and KOH are expected to condense on bare furnace walls, roughly in proportion to their concentration in the flue gas. Further equilibration at the furnace wall temperature will result in conversion of the hydroxides to chlorides and sulfates.



**Figure 5.5 Concentration of corrosive species in flue gas of an RDF-fired boiler as a function of location (and gas temperature) (Daniel, 1991).**

Heavy metal species, such as zinc, lead, and tin, which are present in refuse are subject to oxidation in the flame, and the oxides which are formed during combustion can react with HCl to form metal chlorides. These compounds have low melting points [ $\text{SnCl}_2$ : 246°C (475°F);  $\text{ZnCl}_2$ : 283°C (541°F);  $\text{PbCl}_2$ : 501°C (934°F)] and, when mixed with NaCl, KCl or other metal chlorides, can form eutectic mixtures that melt at temperatures as low as 179°C (350°F). These mixtures are discussed in detail under deposit-related attack in Section 5.3.3.

### 5.3 Mechanisms of Corrosion

Chlorine and sulfur can be involved in both high-and low-temperature corrosion of boiler components. High-temperature corrosion may result from:

- (1) Gas-phase attack by HCl/Cl<sub>2</sub>- or SO<sub>2</sub>/SO<sub>3</sub>- containing gas under locally oxidizing conditions,
- (2) Gas-phase attack by HCl or H<sub>2</sub>S under conditions where the local oxygen partial pressure of the gas is sufficiently low that H<sub>2</sub>S forms a significant proportion of the sulfur species present,
- (3) Liquid-phase attack by direct deposition of molten sulfates or chlorides and their eutectic mixtures that melt at boiler metal temperatures, and
- (4) Liquid phase attack beneath mostly solid deposits on superheater tubes.

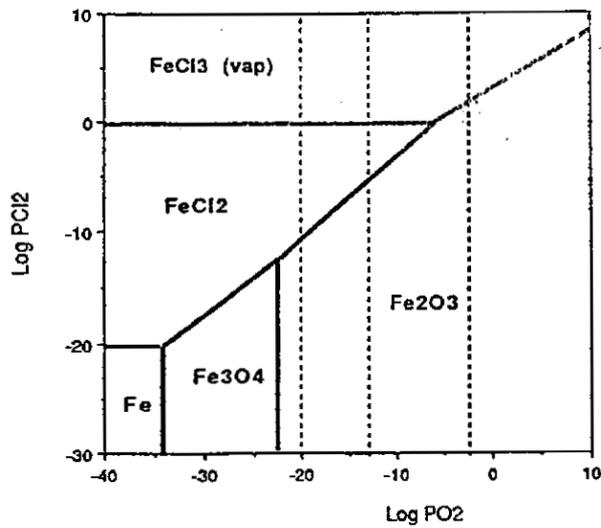
Low-temperature corrosion in the back end of the boiler, usually in the form of pitting, can result from condensation of H<sub>2</sub>SO<sub>4</sub>, H<sub>2</sub>SO<sub>3</sub>, or HCl.

### 5.3.1 Gas Phase Attack in Oxidizing Atmospheres.

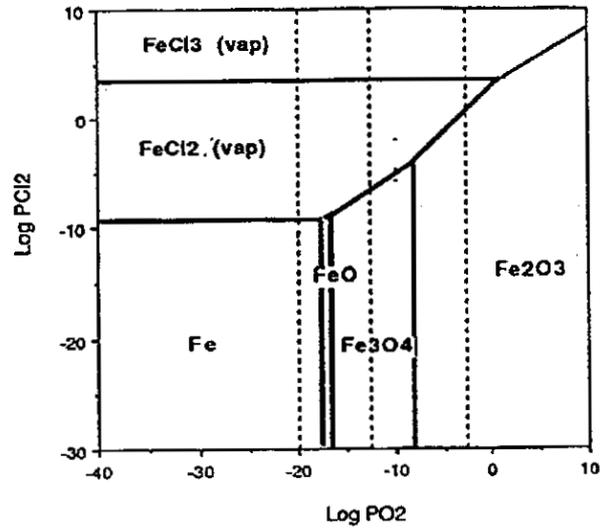
Iron forms two sulfides, FeS<sub>2</sub> and FeS, which melt at 1171 and 1193°C (2140 and 2179°F), respectively, two sulfates, FeSO<sub>4</sub> and Fe<sub>2</sub>(SO<sub>4</sub>)<sub>3</sub>, which decompose at 90 and 480°C (194 and 896°F), respectively, and two chlorides: FeCl<sub>2</sub> and FeCl<sub>3</sub>. These chlorides melt at about 675°C (1247°F) and 305°C (581°F), respectively, and attain significant vapor pressures at relatively low temperatures: 536°C (997°F) and 167°C (332°F), respectively. The ranges of stability of the iron sulfides, sulfates, and chlorides, in terms of the prevailing sulfur or chlorine and oxygen partial pressures in the environment at 400 and 850°C (752 and 1562°F), are shown in simplified Ellingham-Pourbaix diagrams in Figure 5.6. The respective partial pressures of O<sub>2</sub>, S<sub>2</sub> and Cl<sub>2</sub> in the environment of interest can provide information on the corrosion products expected under equilibrium conditions, and, therefore, give some indication of the possible corrosion reactions. The vertical dotted lines in the diagrams indicate the oxygen partial pressure (in atm.) in oxidizing flue gas (log PO<sub>2</sub> = -3), in flue gas from stoichiometric combustion (-13), and fully substoichiometric combustion (-20). An example of the use of equilibrium calculations to explore the variation of oxygen and chlorine partial pressures with oxidant to chlorine-containing fuel ratio has been given by McNallan and Liang (1985).

A knowledge of the equilibrium oxygen and chlorine partial pressure, or oxygen and sulfur partial pressures in the gas can be used to indicate the expected stable corrosion products for those

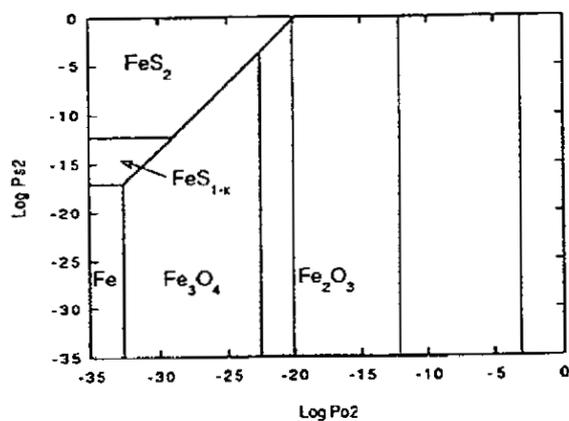
conditions at a given temperature. For example, the expected corrosion product on a furnace wall tube at 752°F subjected to a gas with  $\log P_{O_2} = -20$  and  $\log P_{Cl_2} \geq -10$  would be  $FeCl_2$ . While this compound is solid at 752°F, it has a significant vapor pressure which could lead to relatively rapid loss from the surface. In order to form the more desirable oxide,  $Fe_2O_3$ , the local oxygen partial pressure must be increased, or the chlorine partial pressure decreased to move the gas composition into the zone of stability of the oxide.



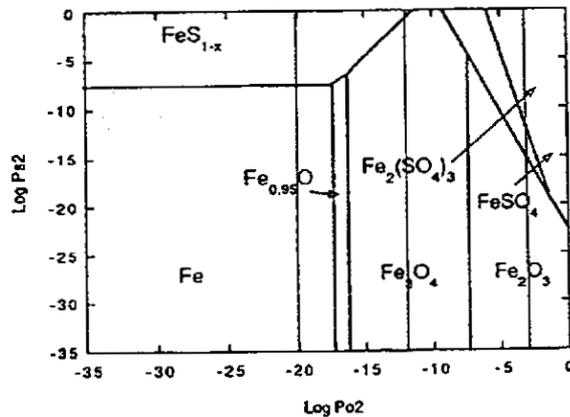
(a) Fe-O-Cl, 400°C (752°F)



(b) Fe-O-Cl, 850°C (1562°F)



(c) Fe-O-S, 400°C (752°F)



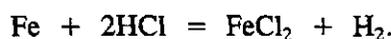
(d) Fe-O-S, 850°C (1562°F)

**Figure 5.6** Simplified Ellingham-Pourbaix diagrams showing corrosion products expected at equilibrium conditions.

Obviously, such diagrams are only useful as an indication of what corrosion products would be expected if equilibrium conditions existed. However, since the equilibration of gas mixtures is catalyzed by oxidized surfaces, it is possible that equilibrium may be attained locally on corroding tube surfaces.

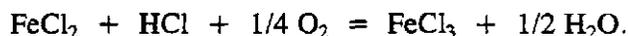
### 5.3.1.1 Corrosion by HCl/Cl<sub>2</sub>

The corrosion of a bare iron or mild steel surface in pure gaseous HCl typically occurs at a relatively low parabolic reaction rate up to 593°C (1100°F) because the FeCl<sub>2</sub> reaction product forms a stable surface layer:



The presence of chlorine-containing compounds in the corrosion scale at the metal-deposit interface has been identified by electron microprobe analyses of failed superheater tubes from municipal combustors (Krause, 1974; Kautz, 1977). Krause (1986) demonstrated by X-ray diffraction analysis of similar corrosion products on combustor probes that the chlorine was present as FeCl<sub>2</sub> over the temperature range 149 to 593°C (300 to 1100°F).

Although FeCl<sub>2</sub> has a vapor pressure of 10<sup>-4</sup> atm. at 536°C (997°F), catastrophic corrosion in 100 percent HCl does not occur until the melting temperature is reached at 675°C (1247°F). However, when oxygen is present, oxidation to FeCl<sub>3</sub> begins at 400°C (752°F), as demonstrated by Ihara and his colleagues (Ihara, 1981) by:



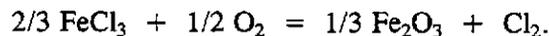
The FeCl<sub>3</sub> is very volatile [10<sup>-4</sup> atm. vapor pressure at 167°C (332°F)], and its evaporation leaves the metal surface exposed to further attack by HCl.

Note that the simplified Ellingham-Pourbaix diagrams in Figure 5.6 suggest that attack of iron by chlorine is not expected to occur in an oxidizing environment (i.e., log P<sub>O<sub>2</sub></sub> > -3) because of the formation of the thermodynamically more stable oxides unless, of course, the partial pressure of

chlorine is very high, or chlorine can directly contact the metal by transporting through the oxide scale via cracks, fissures, or bulk diffusion.

A detailed study of the disruption of the oxide layer on steel by HCl in flue gas was reported by Mayer (1980). Experiments were conducted at a metal temperature of 538°C (1000°F) and a flue gas temperature of 1060°C (1940°F). Without HCl in the flue gas, a continuous non-porous scale consisting of FeO, Fe<sub>3</sub>O<sub>4</sub>, and Fe<sub>2</sub>O<sub>3</sub> was formed. With 0.1 vol. percent HCl in the gas, the inner scale layers were continuous, but the outer Fe<sub>2</sub>O<sub>3</sub> layer became blistered and cracked. This Fe<sub>2</sub>O<sub>3</sub> layer in turn became porous and discontinuous when the HCl concentration was increased to 0.2 vol. percent. A further increase of HCl content to 0.8 vol. percent caused complete disintegration of the Fe<sub>2</sub>O<sub>3</sub> layer, and the Fe<sub>3</sub>O<sub>4</sub> layer became irregular and porous. The maximum content of HCl that was investigated (2 vol. %) destroyed the continuity of both outer layers, exposing the underlying FeO to attack by oxygen and HCl.

Inasmuch as FeCl<sub>2</sub> has been found as a corrosion product in the metal temperature range 149 to 260°C (300 to 500°F), where HCl has little activity, the corrosive agent in this zone must be elemental chlorine formed by oxidation of HCl. As shown by Brown, et al., (1947), chlorine attacks steel rapidly in this lower temperature range. In addition to formation from HCl, the elemental chlorine can result from oxidation of FeCl<sub>3</sub> in the scale layer:



A cyclic reaction can then occur beneath the scale, with the chlorine attacking the tube metal to form more FeCl<sub>3</sub>. The FeCl<sub>2</sub> scale also can be involved in the same type of cyclic system, because it is subject to oxidation to Cl<sub>2</sub>, as demonstrated by Fassler and his associates (1968):

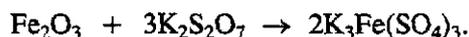


### 5.3.1.2 Corrosion by SO<sub>2</sub>/SO<sub>3</sub>

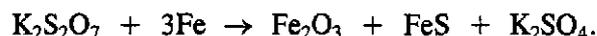
As shown in Figure 5.6, the iron sulfides have narrower stability ranges than the iron chlorides and form at very low oxygen partial pressures. Experimental results (Ross, 1965) have shown that a S<sub>2</sub>

partial pressure of  $10^{-13}$  atm. was sufficient to produce FeS when the partial pressures of  $\text{SO}_2$  and  $\text{O}_2$  were below  $10^{-14}$  atm., whereas at higher  $\text{SO}_2$  partial pressures, iron oxides formed. When oxides were present on the iron surface, higher  $\text{S}_2$  partial pressures and perhaps moisture (Kubaschewski, 1953) were needed to form FeS.

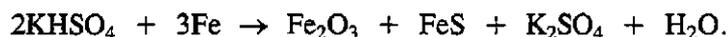
One of the most likely scenarios for sulfidation attack under oxidizing combustion conditions in boilers is through alkali sulfates or pyrosulfates that are formed in the flame and are deposited on the furnace walls. The type of reaction involved, at temperatures near  $260^\circ\text{C}$  ( $500^\circ\text{F}$ ) and higher, is that proposed many years ago by Corey, et al., (1945 and 1949) and by Coates (1968), which involve fluxing of the protective oxide layer by the reaction:



Direct attack of the tube metal by pyrosulfate and bisulfate would then occur via:



and

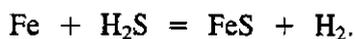


The high corrosivity of these salts is probably related to the fact that they have relatively low melting points, that is, about  $302^\circ\text{C}$  ( $575^\circ\text{F}$ ) for  $\text{K}_2\text{S}_2\text{O}_7$  and  $213^\circ\text{C}$  ( $415^\circ\text{F}$ ) for  $\text{KHSO}_4$ . In addition to laboratory evidence showing the corrosivity of these materials, it should be pointed out that azide and pH tests made on individual corrosion probe specimens typically show the presence of sulfide and the presence of acidic hydrolyzing salts (Miller, 1972).

The presence of FeS in the scale formed on tube surfaces, whether the scale is wholly sulfide or a sulfide-oxide mixture, is detrimental because the diffusion of Fe in FeS is faster than through  $\text{Fe}_3\text{O}_4$ , so that the rate of metal wastage is increased. In addition, because a larger volume of FeS is formed than  $\text{Fe}_3\text{O}_4$ , for a given amount of Fe consumed, sulfide scales are more susceptible to spallation than are oxide scales.

### 5.3.2 Gas Phase Attack in Reducing Atmospheres.

In reducing (substoichiometric) environments (where  $\log P_{O_2} \leq -13$  atm. at 850°C/1562°F in Figure 5.6) oxide phases would be absent or discontinuous, and iron sulfide or chloride can form directly on the metal surface when  $\log P_{Cl_2} \geq -9$  atm. or  $\log P_{S_2} \geq -8$  atm. The rate of corrosion then depends on temperature (which determines the vapor pressure of the corrosion product, and whether it is molten), on the activity of chlorine or sulfur in the environment up to some threshold level (Brooks, 1985), which determines the amount of surface coverage by chloride or sulfide, and on the gas flow rate, which controls the rate of evaporative loss. Under these conditions, direct gaseous sulfidation attack can occur to form the sulfide, by:



The presence of FeS on probe specimens in the metal-scale interface region has been confirmed by X-ray diffraction in a number of studies.

Excessive furnace wall corrosion first noted in European combustors during the 1970's was found to be associated with high CO levels in the flue gas as well as chloride in the tube deposits (Thoemen, 1972). The combined effects of CO and HCl on corrosion were investigated under controlled laboratory conditions by the Central Electricity generating Board in the U.K. using gas mixtures. Initially, a N<sub>2</sub>-O<sub>2</sub>-H<sub>2</sub>O-SO<sub>2</sub> gas mixture was used to simulate the gas composition near the walls. The corrosion rates were parabolic (decreasing with time), and the addition of 400 or 2,000 ppm HCl did not greatly affect the corrosion rates. A thin layer of chloride was found at the metal-scale interface, and the scales formed in the presence of HCl were less adherent, and had a greater tendency to crack and spall (Brooks and Glover, 1981). Latham, et al. (1991) commented that "this indicated that the presence of a chloride species in a scale does not necessarily imply that rapid attack must result..."

Mayer, et al. (1983) studied the corrosion of mild steel in oxidizing or reducing conditions containing HCl (or Cl<sub>2</sub>), and postulated that the effect of the chlorine species is to cause disruption of the normal, protective oxide scale through cracking or blistering or, at high HCl levels (0.8 vol. percent), complete disintegration of the outer Fe<sub>2</sub>O<sub>3</sub> layer, and the development of porosity in the inner

$\text{Fe}_3\text{O}_4$  layer. These changes result in some acceleration, but not a catastrophic increase in the rate of corrosion compared to air oxidation.

When the oxygen in the gas was replaced by CO, the corrosion rates were parabolic in the absence of HCl, but faster than in the  $\text{O}_2$ -containing gas mixture (Brooks and Meadowcroft, 1983). When 400 ppm HCl was introduced, linear oxidation kinetics were observed. Once transition to linear kinetics had occurred, there was little subsequent dependence of corrosion rate when the HCl content was increased to 2,000 ppm. The scales formed were loosely adherent, porous, and multilayered with bands of iron oxide and iron sulfide; there was no evidence of chloride at the metal-scale interface, nor as internal penetrations, as often was found in boiler furnace wall tubes. The effect attributed to HCl was the promotion of the formation of thicker, more porous, less adherent scales. Placing deposits (derived from burning high-chlorine coal) on the samples during the tests increased the corrosion rates, but did not change the form of the kinetics or the scale morphology.

Further work by Brooks and Gilroy (1984) under experimental conditions where the  $\text{SO}_2$  in the simulated flue gas was replaced with  $\text{H}_2\text{S}$  showed that the corrosion rates were linear whether or not HCl was present in the gas. The rates were similar to those measured in the  $\text{SO}_2$ -containing gas when the experimental conditions were expected to have catalyzed the equilibration of the gas mixtures. Also, there was no obvious effect on the corrosion rates of an addition of 400 ppm HCl. Brooks and Gilroy (1984) subsequently found by that, in the  $\text{N}_2$ -CO- $\text{H}_2\text{O}$ - $\text{SO}_2$  simulated flue gas under conditions where the conversion of  $\text{SO}_2$  to  $\text{H}_2\text{S}$  was weakly catalyzed, the corrosion rate of mild was lower than in the  $\text{H}_2\text{S}$ -containing gas mixture.

Latham et al., (1991) concluded that the conditions for the rapid furnace wall corrosion observed in boilers burning high-chlorine coals probably require that the combustion gas is locally equilibrated at the boiler wall and, since equilibration is slow at the prevailing wall temperatures, and that the presence of thick corrosion products, deposits, or slagging also may be necessary. Although these results did not clearly assign a role for chlorine, the action of HCl to promote weakly-adherent, cracked, and porous scales could provide easy access of the gas to the alloy surface, and provide a larger area of catalytic surface.

The major additions to Fe-based engineering alloys, such as Ni and Cr, also form chlorides and sulfides that are less thermodynamically stable than the corresponding oxides, so that attack of these by chlorine or sulfur is also more likely in an oxygen-deficient environment. Hossain (1981) pointed out

that the free energies of formation for oxides, chlorides, and sulfides of the elements usually found in boiler tubes are such that the sulfides would be formed preferentially to the chlorides.

### 5.3.3 Deposit-Related Corrosion.

Corrosion by molten salts containing sulfur and chlorine occurs primarily on furnace wall tubes, where low-melting compounds or eutectic mixtures are formed in deposits. The molten salts can act as a flux for protective oxides on the tubes, thus exposing the surfaces to continued oxidation and/or chlorination or sulfidation. The metal chlorides are the most likely sources of molten salt corrosion because of their low melting points and fluxing properties. In corrosion probe studies with municipal refuse (Kautz, 1977), Pb, Zn and Sn often were found at the interface of the metal and corrosion products in the same region with chlorine. The chlorides of these metals are relatively low-melting compounds that would have been liquid at probe metal temperatures. Such chlorides probably formed by reaction of the metal oxides with HCl in the flue gas, as there was no evidence for their existence as chlorides in the unburned waste.

Daniel, et al., (1986) reported that the deposit on a badly corroded wall tube from a refuse-fired boiler contained 22.7 wt. percent chlorine. Analysis by X-ray diffraction identified NaCl in the deposit, and electron microprobe X-ray scans showed that K, Zn, and Fe also were associated with the chlorine. Compounds such as NaCl, KCl, and FeCl<sub>2</sub>, which are not low-melting compounds, can form eutectic mixtures of low-melting point with the Pb, Zn, and Sn chlorides. Many of these combinations of chlorides melt below 260°C (500°F) as shown in Figure 5.7. The two mixtures with the lowest melting points involve FeCl<sub>3</sub> with NaCl or PbCl<sub>2</sub>. Thus, in the presence of either of these chlorides, FeCl<sub>3</sub> formed as a corrosion product on steel may become part of a molten salt mixture rather than volatilize from the deposit.

The eutectic mixtures formed by ZnCl<sub>2</sub> and SnCl<sub>2</sub> all would be molten at wall tube temperatures and may be responsible for much of the corrosion of wall tubes by municipal refuse. As shown in Figure 5.7, all of the PbCl<sub>2</sub> eutectics except that with FeCl<sub>3</sub> would only melt at superheater temperatures. Chlorides of K, Mg, and Ca also can be part of low-melting eutectic mixtures. Consequently, boiler deposits from refuse firing can include a large number of components that have

the potential for causing molten salt attack on the furnace wall or superheater tubes. This contrasts significantly with coal firing.

Otsuka, et al., (1993) used simulated deposits to investigate the relative effects of chlorides and sulfates on the corrosion of austenitic steels and Ni-base alloys. They found that high-Ni alloys such as 825, G3, 625, 690, 600, and pure Ni exhibited good corrosion resistance to chloride-based deposits at 400°C (752°F), whereas Fe-based alloys such as 304 and 316L were severely corroded. In contrast, for predominantly sulfate deposits (containing a small amount of chloride) expected to form on superheater tubes, the corrosion behavior at 550°C (1022°F) appeared to be a function of alloy Cr content, with the higher-Cr alloys corroding slowest. For alloys of similar Cr content, increasing Ni content appeared to degrade the resistance to corrosion. The best-performing alloy in all the environments tested was Alloy 625.

The presence of a solid alkali chloride deposit on the metal surface increases the corrosion process if SO<sub>2</sub> is present in the flue gas. In this case, the chloride is converted to sulfate, with the release of HCl in the deposit:

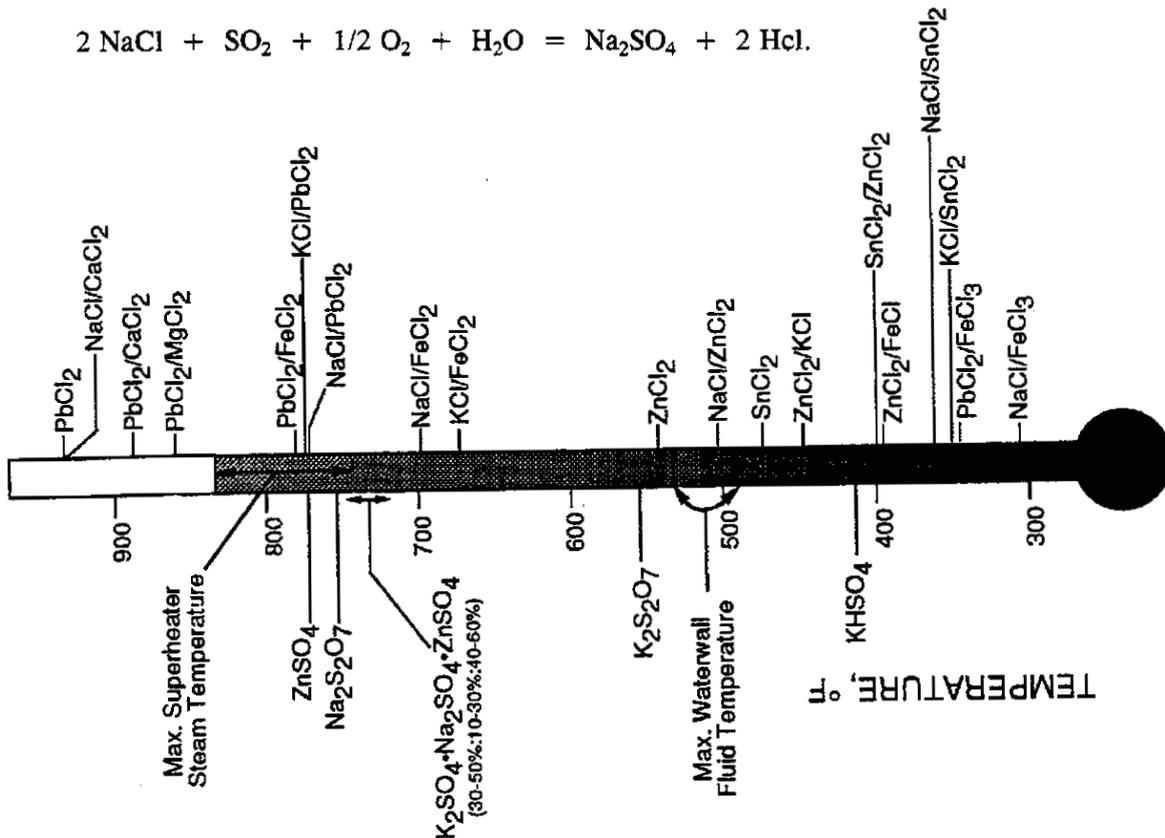


Figure 5.7 Melting temperatures of various salts found in WTE combustors.

This role of SO<sub>2</sub> was demonstrated in laboratory experiments (Miller, 1972) in which alloys were exposed to sulfate-chloride salt mixtures in a synthetic flue gas with and without SO<sub>2</sub>, and has been observed in simulated gas turbine conditions (Hossain, 1981). As shown in Table 5.1, introduction of only 250 ppm SO<sub>2</sub>, typical of refuse combustion, resulted in large increases in the corrosion rates. Increasing the SO<sub>2</sub> concentration to 2500 ppm, typical of coal-fired boilers, caused a significant increase on the attack of C-steel, but had only a minor effect on T11. Type 321 stainless steel underwent slightly less corrosion at the higher SO<sub>2</sub> level, which may be attributable to experimental variation. Increasing the metal temperature from 427 to 538°C (800 to 1000°F) caused much more increase in the corrosion rate than did an increase in the amount of NaCl in the deposit, as shown in Table 5.2. These results indicate that only small amounts of alkali chloride in the tube deposits will cause serious corrosion. It is significant that without a deposit on the metal the gas phase attack by the synthetic flue gas containing 250 ppm SO<sub>2</sub> was slight, showing that the formation of HCl in the deposit is the critical factor.

**Table 5.1 Effects of SO<sub>2</sub> concentration on corrosion rates in sulfate-chloride mixture at 1000°F<sup>(a)</sup> (Miller, 1972).**

Alloy	No SO <sub>2</sub> <sup>(b)</sup>	Corrosion Rates, mils/month	
		250 ppm SO <sub>2</sub>	2500 ppm SO <sub>2</sub>
Carbon steel	20	74	99
T11	10	62	68
TP321	1	15	6

(a) Synthetic flue gas: 80% air, 10% CO<sub>2</sub>, 10% H<sub>2</sub>O.

(b) Mixture consisted of 78 K<sub>2</sub>SO<sub>4</sub>-21Na<sub>2</sub>-SO<sub>4</sub>-1NaCl.

The effect of NaCl on the surface of a metal under oxidizing conditions was investigated for various alloys by Hancock and coworkers (1972 and 1973). The experimental techniques employed were hot-stage microscopy and measurement of the natural vibration frequencies of freely-suspended bars. With Fe-based alloys, extensive blistering and cracking of the oxide scale occurred when solid NaCl was used to contaminate the specimen surface, the severity of the attack increasing with increasing temperature.

**Table 5.2 Effect of deposits and temperature on corrosion rates in flue gas atmospheres<sup>(a)</sup> (Miller, 1972).**

Alloy	Corrosion Rates, mils/month					
	No Deposit		Deposit A <sup>(b)</sup>		Deposit B <sup>(c)</sup>	
	800 F	1000 F	800 F	1000 F	800 F	1000 F
Carbon steel	1	8	6	74	18	68
T11	1	5	3	62	14	62
TP321	0	0	< 1	15	< 1	17

(a) Synthetic flue gas: 80% air, 10% CO<sub>2</sub>, 10% H<sub>2</sub>O, 250 ppm SO<sub>2</sub>.

(b) Deposit A: 78 K<sub>2</sub>SO<sub>4</sub> - 21 Na<sub>2</sub>SO<sub>4</sub> - 1 NaCl.

(c) Deposit B: 75 K<sub>2</sub>SO<sub>4</sub> - 20 Na<sub>2</sub>SO<sub>4</sub> - 5 NaCl.

Below the melting point of the salt, the attack was localized; while above the melting point, widespread failure of the scale occurred (Hancock, et al., 1972; Hurst, et al., 1973). Similar effects were noted for a range of Ni-base alloys. Any reaction between the oxide and the chloride had no effect on the overall oxidation rate--apparently the corrodent must have access to the metal surface before accelerated oxidation can occur (Davies, 1972). The vibration technique demonstrated that mechanical failure of the surface oxide scale occurs continually, even in isothermal conditions, on all Fe- and Ni-based alloys studied. Any contaminant in the gas therefore is provided with direct access to the metal surface. Concentration profiles across a section of mild steel corroded under such conditions showed a large concentration of chlorine at the metal-scale interface, with little or no chlorine present throughout the scale itself. A mechanism of scale disruption proposed by Hoare (1969) involves direct reaction between the metal and the chlorine to produce a volatile oxychloride.

As mentioned earlier, sulfur-bearing compounds play an important role with regard to molten salt attack over the range of temperatures experienced by boiler tubes. For example, the most corrosive salts found in laboratory tests intended to simulate the conditions experienced at the waterwalls of coal-fired boilers (Miller, 1972) at 316°C (600°F) were the pyrosulfates and the bisulfates. Since the corrosion reactions, which are electrochemical in nature, can take place more readily in liquids than in solids or gases, the presence of a liquid phase is of great importance. The

melting points of these salts may be further lowered by the Zn and Pb salts also shown to be present on corroded specimens from probe exposures.

Overall, given the wide range of compounds that may be present in deposits formed on tubes in waste-fired boilers and that can give rise to low-melting salts, there are a number of possible scenarios available to explain the often-observed accelerated corrosion. Krause (1986) attempted to rationalize the sequence of chemical reactions that may occur in these deposits and lead to corrosion. Figure 5.8 is a schematic representation of the proposed mechanism, which explains the dimpled surface structures that are usually observed on corroded tubes by the presence of both FeS and FeCl<sub>2</sub> phases at the metal/scale interface. Dimpling is a result of the variation in corrosion resulting from these phases, which coat adjacent areas on the tubes. Because of the cation vacancies in the FeS structure, there is a higher diffusion rate of iron ions through the FeS film than through the FeCl<sub>2</sub> film, which is more ionic in character, has fewer cation vacancies, and thus a lower cation diffusion rate. The driving force for this diffusion in both cases is the iron concentration gradient established by the formation of the more stable iron oxides at the exterior surface of these films. The oxide formation depends upon the SO<sub>2</sub> or O<sub>2</sub> penetrating the mixed oxide scale and the other deposits. The presence of FeCl<sub>2</sub> or FeS at the metal/scale interface suggests that the O<sub>2</sub> partial pressure at the metal surface is reduced, and/or the Cl<sub>2</sub> or S<sub>2</sub> partial pressures are elevated (see Figure 5.6) so that oxide and/or chloride or sulfide can coexist. However, the chloride and sulfide are slowly oxidized to Fe<sub>2</sub>O<sub>3</sub> at the outer surface of the scale away from the metal substrate, so that the Cl<sub>2</sub> or S<sub>2</sub> partial pressure in the respective phase is increased and the reaction proceeds by attack of the substrate metal.

The observed low pH-values of the deposits in refuse-fired boilers also suggest the presence of the acid sulfates or pyrosulfates. ZnCl<sub>2</sub> and FeCl<sub>2</sub> would also give an acidic reaction upon hydrolysis. However, the presence of bisulfates, pyrosulfates, or alkali trisulfates has not been proved by X-ray diffraction. This, of course, does not mean that they were not present, since studies (Miller, 1972) have shown that these materials are difficult to detect in amounts less than 5 percent. Dilution of these phases with normal sulfates reduces the attack on the steels by very significant amounts.

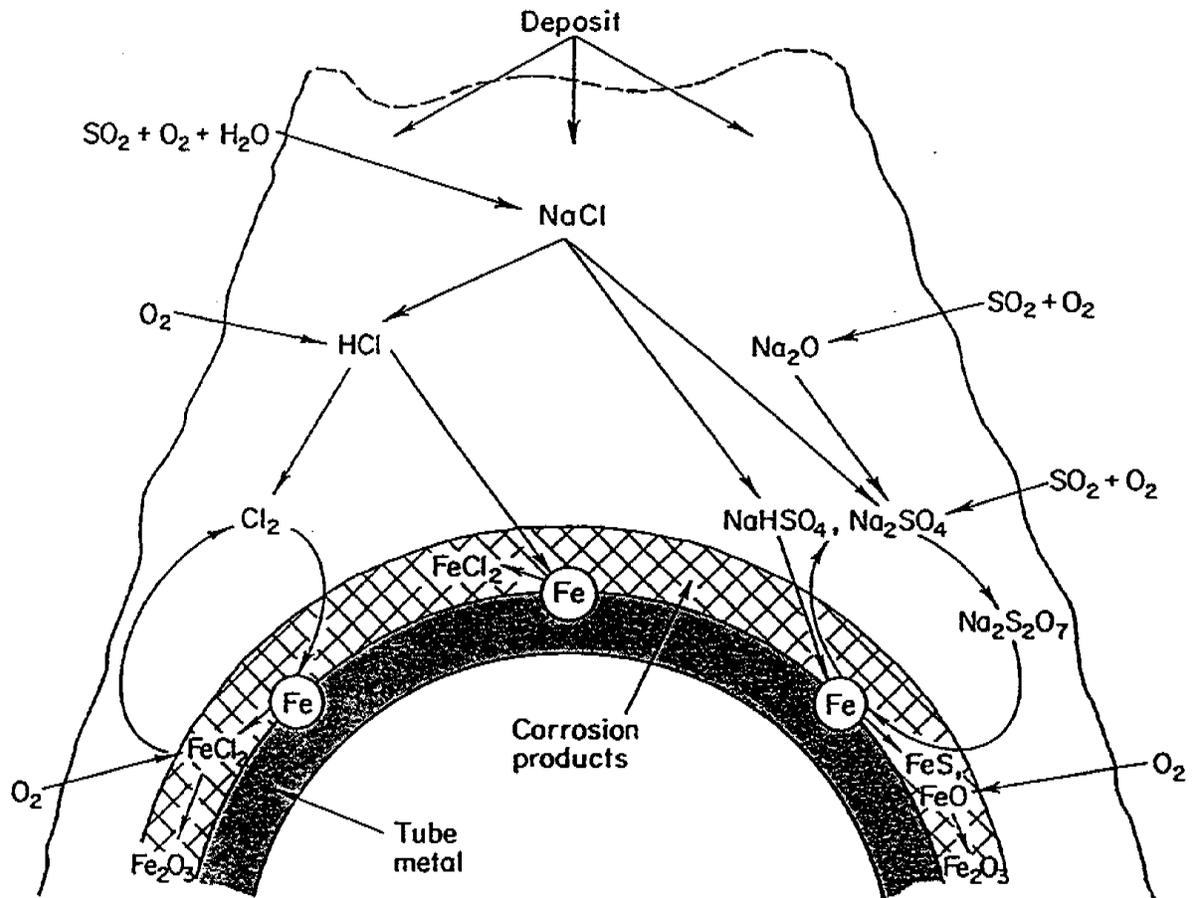


Figure 5.8 Sequence of chemical reactions explaining corrosion of combustor boiler tube (Krause, 1986).

### 5.3.4 Effect of Temperature

Temperature has an important effect on the corrosion reactions in combustors. Early tests described by Vaughan, et al., (1974) showed that both the metal and the gas temperatures influenced the corrosion rates. Data for carbon steel are shown in Figures 5.9 and 5.10 as Arrhenius plots, which represent the corrosion rates as a function of the metal temperature and gas temperature, respectively. At gas temperatures of 760 and 593°C (1400 and 1100°F), the corrosion rates and the temperature-dependence of corrosion were significantly lower than at the higher gas temperatures (Figure 5.9), especially at metal temperatures of 371°C (700°F) and higher. The activation energies determined from these plots were very low compared to that expected (approximately 35 kcal/mole) for simple oxidation, and ranged from about 5 to 0.3 kcal/mole. In addition, it should be noted that for these combustor corrosion data, no unique activation energy value could be assigned for corrosion at any given metal or gas temperature. At the lower metal (and gas) temperatures low activation energies were measured, consistent with corrosion attack by low-melting compounds. At the higher metal temperatures, when the gas temperatures were also high and corrosion was expected to proceed by gas-metal interactions such as sulfidation/oxidation (which are characterized by well-defined diffusion processes), higher activation energies were measured.

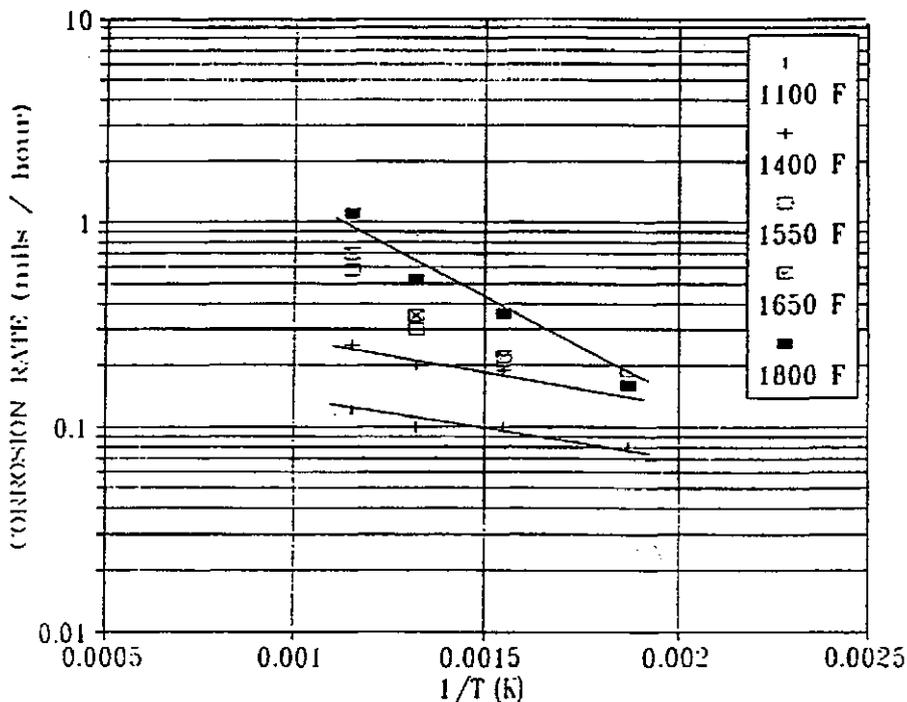
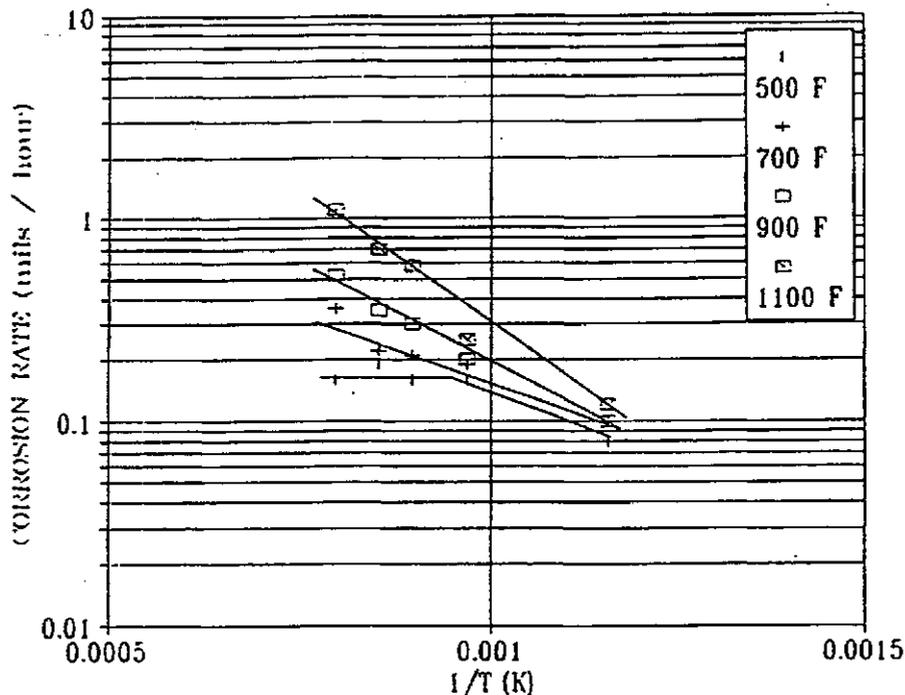


Figure 5.9 Corrosion rates of carbon steel in MSW combustors as a function of metal temperature. (The legend indicates data points for different gas temperatures.)



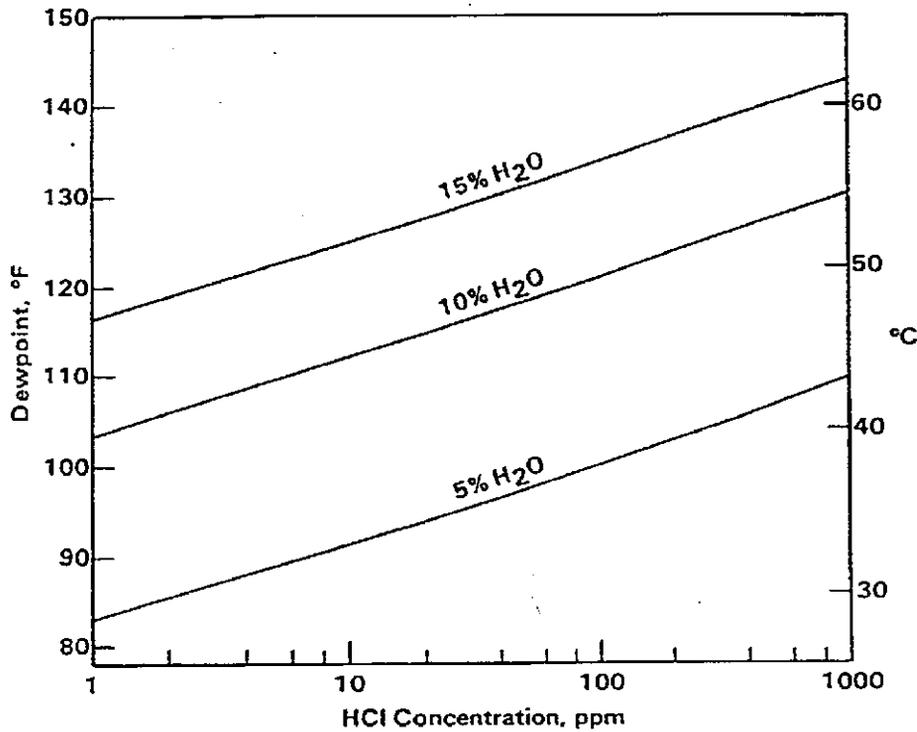
**Figure 5.10** The effects of gas temperature on the corrosion rate of carbon steel in MSW combustors. (The legend indicates data points for different metal temperatures.)

Laboratory studies of simulated deposits (Otsuka, et al., 1993) have shown that, for both sulfate-based and chloride-based deposits, corrosion was only slight to negligible at temperatures below the melting point of the deposit. As soon as constituents of the deposits melted, rapid corrosion was observed. Also, in the absence of a deposit, corrosion from a simulated flue gas containing 1500 ppm HCl was slight at temperatures up to 550°C (1022°F).

### 5.3.5 Condensed Acid Attack.

Corrosion by condensed  $H_2SO_4$ ,  $H_2SO_3$ , or HCl can occur whenever the flue gas stream is cooled below the respective dewpoints of  $SO_3$ ,  $SO_2$ , or HCl. This situation is most likely to occur in the air preheater, electrostatic precipitator, ducts, and stack. Based on the nature of the fuel, refuse combustors have more HCl than  $SO_2$  in the flue gas. Therefore HCl attack would be predominant in the scrubber and in downstream components of such units. Fortunately, the dewpoint of HCl is low, falling in the range 27 to 60°C (80 to 140°F) depending on the HCl concentration and the water content of the gas, as shown in Figure 5.11 (Krause, 1984). Consequently, attack by condensed HCl rarely occurred before the days of wet scrubbing of the flue gas. Condensed HCl contributes to the corrosion

of scrubbers designed to remove S-oxides from coal-fired boilers because it has a synergistic action with the sulfurous and sulfuric acids generated.



**Figure 5.11 Hydrochloric acid dewpoint as a function of HCl and H<sub>2</sub>O concentrations (Krause, 1984).**

Because the chloride corrosion products formed on steel absorb moisture readily from the air, HCl can form on the metal surface during periods of downtime. Corroded tubes have been observed to become “dripping wet” under such circumstances in humid summer weather, and corrosion rates are enhanced. As a result, it is recommended that auxiliary heating be used to maintain dry conditions during downtime of boilers fueled with chlorine-containing fuels.

#### 5.4 Overall Summary of Understanding of Factors Affecting Tube Life

Corrosion of the heat transfer surfaces of a WTE boiler can result from several sources:

- (1) Direct attack by corrosive gas in areas of incomplete combustion, especially where the flame impinges on the metallic surfaces.
- (2) Rapid dissolution of protective oxide scales and of the metal surface by low-melting *point* salts, (French 1991) predominantly chlorides, that condense on the furnace walls, and sometimes on the convection bank tubes. Consideration of the processes occurring in the combustion zone suggests that salts deposited in the convection bank should be sulfate-rich, rather than chloride-rich, hence, higher-melting, but this is not always the case. Where chlorides can be deposited on the higher-temperature superheater tubes, the rate of attack can be rapid.
- (3) Gas phase oxidation of the superheater tubes, accelerated by the effects of HCl and mechanical cleaning which can act to cause cracking and spalling of the otherwise relatively protective scales.

Practically all of the chlorine in refuse is volatilized during combustion; it is estimated that the amount of HCl found in boiler flue gases is about 80 ppm for each 0.1 percent of chlorine in the fuel. The estimated current level of chlorine in MSW is at least 1.3 percent, suggesting that the HCl content of the combustion gases could exceed 1,000 ppm.

Compounds of alkali metals, Na and K, in MSW are subject to oxidation in the flame, and the oxides which are formed during combustion can react with HCl to form metal chlorides. The concentrations of chlorine-, sulfur-, and alkali metal-species in the flue gas change as it cools on passage through the boiler. At the concentrations present in the flue gas, NaCl, NaOH, KCl, and KOH are expected to condense on furnace walls, roughly in proportion to their concentration in the flue gas. Further equilibration at the furnace wall temperature will result in conversion of the hydroxides to chlorides and sulfates, so that furnace wall deposits are expected to be mainly chlorides, with some sulfates. NaCl and KCl have been identified by X-ray diffraction analysis of probe deposits collected from operating WTE units.

If the gas is cooled below about 649°C (1200°F) before it enters the convection zone, most of the hydroxides and chlorides can condense out on the furnace walls, so that deposits in the convection zone will be predominantly sulfate-rich. Further cooling below about 527°C (981°F) HCl concentrations would decrease to near zero because of reaction with alkali silicates. In practice, these gas-solid reactions generally are slow at the lower temperatures. Therefore, most of the chlorine leaving the boiler remains in the flue gas as HCl, and there is little chloride (as NaCl or KCl) in the fly ash.

Heavy metal species, such as zinc, lead, and tin which also are present in refuse, can form metal chlorides in the flame. These compounds have relatively low melting points. However, when mixed with NaCl, KCl, or other metal chlorides, resulting compounds could be molten at furnace wall-tube temperatures. The two such mixtures with the lowest melting points involve FeCl<sub>3</sub> with NaCl or PbCl<sub>2</sub> (approximately 152°C/305°F, and 171°C/340°F, respectively). The eutectic mixtures formed by ZnCl<sub>2</sub> and SnCl<sub>2</sub> all would be molten at wall tube temperatures, whereas all of the PbCl<sub>2</sub> eutectics (except that with FeCl<sub>3</sub>) would only melt at superheater temperatures. Chlorides of K, Mg, and Ca also can be part of low-melting eutectic mixtures.

Corrosion is only slight to negligible at temperatures below the melting point of the deposits. As soon as constituents of the deposits melt, rapid corrosion occurs. However, the presence of a solid alkali chloride deposit on the metal surface can aggravate the corrosion process if SO<sub>2</sub> is present in the flue gas. In that case, the chloride is converted to sulfate, with the release of HCl in the deposit.

Low pH-values are measured for the deposits in refuse-fired boilers, which also suggest the presence of the acid sulfates or pyrosulfates. The lowest-melting pyrosulfate, K<sub>2</sub>S<sub>2</sub>O<sub>7</sub>, melts at approximately 293°C (560°F).

Corrosion by direct action of HCl gas is slow in the metal temperature range 149 to 260°C (300 to 500°F). However, chlorine attacks steel rapidly in this temperature range. At a metal temperature of 538°C (1000°F) and a flue gas temperature of 1060°C (1940°F), corrosion by combustion gas without HCl results in a continuous non-porous scale consisting of FeO, Fe<sub>3</sub>O<sub>4</sub>, and Fe<sub>2</sub>O<sub>3</sub> being formed. With 0.1 vol. percent HCl in the combustion gas, the inner scale layers are continuous, but the outer Fe<sub>2</sub>O<sub>3</sub> layer becomes blistered and cracked. This Fe<sub>2</sub>O<sub>3</sub> layer in turn becomes porous and discontinuous when the HCl concentration is increased to 0.2 vol. percent. A further increase of HCl content (to 0.8 vol. percent) causes complete disintegration of the Fe<sub>2</sub>O<sub>3</sub> layer,

and the  $\text{Fe}_3\text{O}_4$  layer becomes irregular and porous. The maximum content of HCl that was investigated (2 vol. %) destroyed the continuity of both outer layers, exposing the underlying FeO to attack by oxygen and HCl. Nevertheless, in the absence of a deposit, corrosion from a simulated flue gas containing 1,500 ppm HCl was found to be slight at metal (and gas) temperatures up to 550°C (1022°F).

Corrosion rates and the temperature-dependence of corrosion measured in field tests were significantly lower at gas temperatures below 760°C (1400°F), than at the higher gas temperatures, especially at metal temperatures of 371°C (700°F) and higher. At the lower metal (and gas) temperatures, results indicated that the corrosion attack was by low-melting compounds. At the higher metal and gas temperatures, the corrosion proceeded by gas-metal interactions (which are characterized by well-defined diffusion processes), higher activation energies were measured.

In nominally reducing conditions, corrosion of low alloy steel at 400°C (752°F) by flue gas (at the same temperature) without HCl occurs at a parabolic rate. With 400 ppm HCl in the flue gas, corrosion rates of mild steel are linear with time. Increasing the HCl content of the gas to 2,000 ppm almost doubled the linear corrosion rate; there is little effect of further increases above 2,000 ppm HCl on corrosion rates. The increase in the corrosion rate resulting from the presence of HCl in a reducing atmosphere was attributed to oxidation-sulfidation promoted by scale disruption through  $\text{FeCl}_2$  subsequent formation and volatilization. The formation of volatile  $\text{FeCl}_2$  induces scale porosity. This higher porosity promotes spalling during service.

Corrosion by condensed  $\text{H}_2\text{SO}_4$ ,  $\text{H}_2\text{SO}_3$ , or HCl can occur whenever the flue gas stream is cooled below the respective dewpoints of  $\text{SO}_3$ ,  $\text{SO}_2$ , or HCl. However, the dewpoint of HCl is the lowest of the three, so that no extra measures are required to prevent condensation. However, if condensation does occur, HCl can contribute to severe pitting attack.

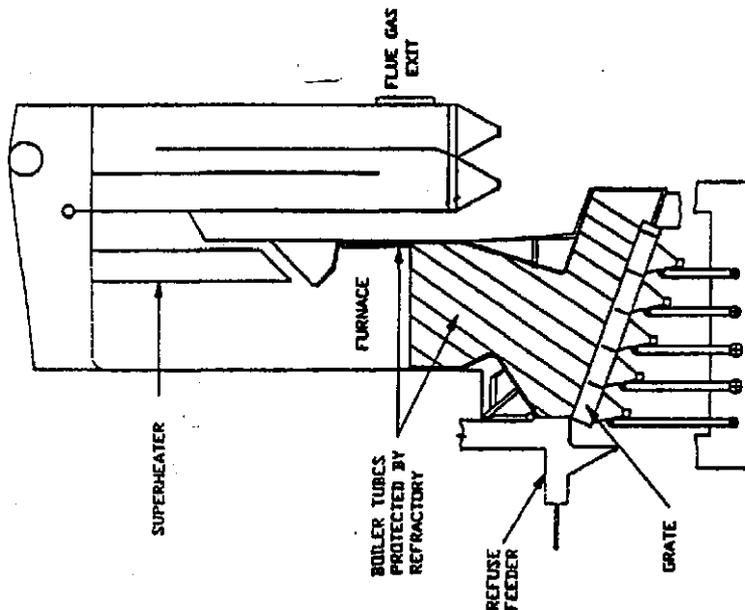
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## 6. Overview of Metal Wastage Experienced in Waste-Fired Steam Generators

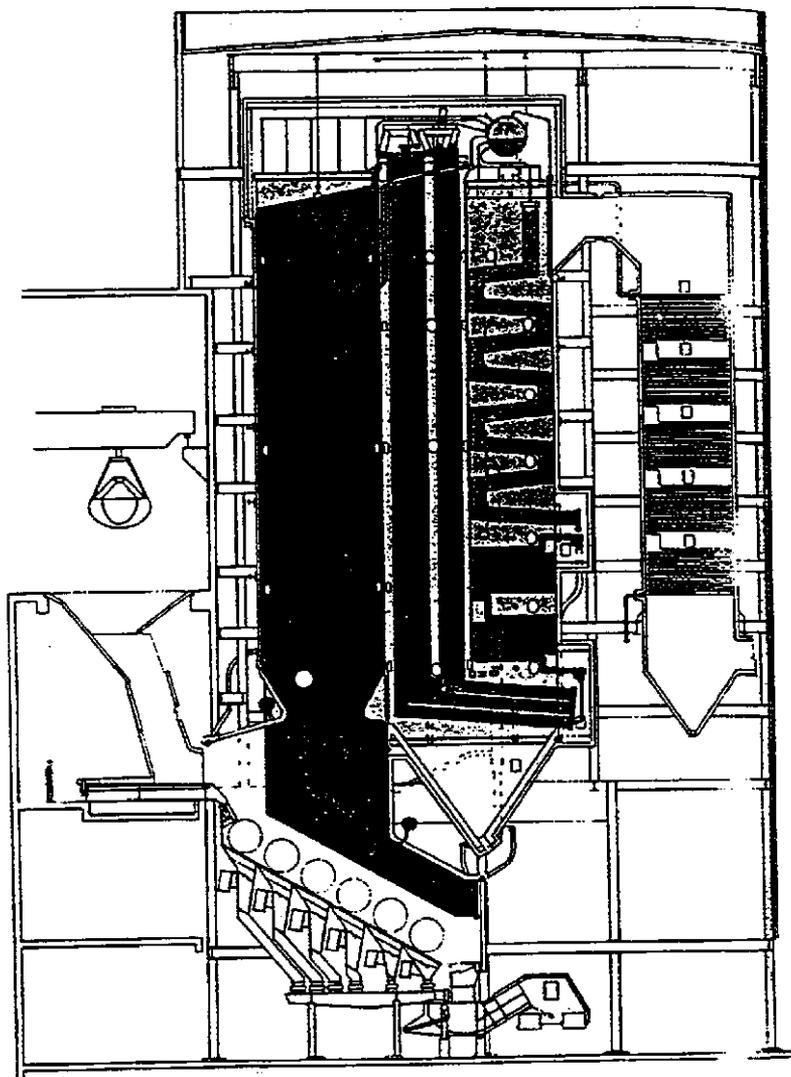
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### 6.1 Influence of Boiler Design

In a modern mass-burn boiler, the combustion chamber typically is enclosed by membrane waterwalls, the lower regions of which are protected from corrosion. The top of the radiant zone consists of bare waterwalls. The combustion gas passes from the radiant zone into a convection section containing the steam generator, superheater, and economizer tube banks. The configuration of the boiler may parallel that of a conventional coal-fired boiler, in which the superheater is situated at the top of the combustion chamber in the entrance to the convection zone as illustrated in Figure 6.1 or, alternatively, the convection zone may consist of several passes with the superheater situated a considerable distance from the combustion chamber, as is shown in Figure 6.2.



**Figure 6.1 Schematic elevation of a waste-to-energy boiler with the superheater at the top of the furnace zone (Strach, 1989).**



**Figure 6.2 Schematic elevation of a waste-to-energy boiler with the superheater located in the back pass (Gursky, 1992). Used by permission.**

### **6.1.1 Design of Mass-Burn Plant**

The lower part of the combustion chamber in a multi-pass mass-burn boiler usually is lined with silicon carbide to avoid corrosion. In this zone, the combustion gas is cooled to approximately 954°C (1750°F) to minimize corrosion of the upper, unprotected waterwalls. Corrosion of the convection pass tubes can be minimized if the combustion gas temperature is cooled to the range 650 to

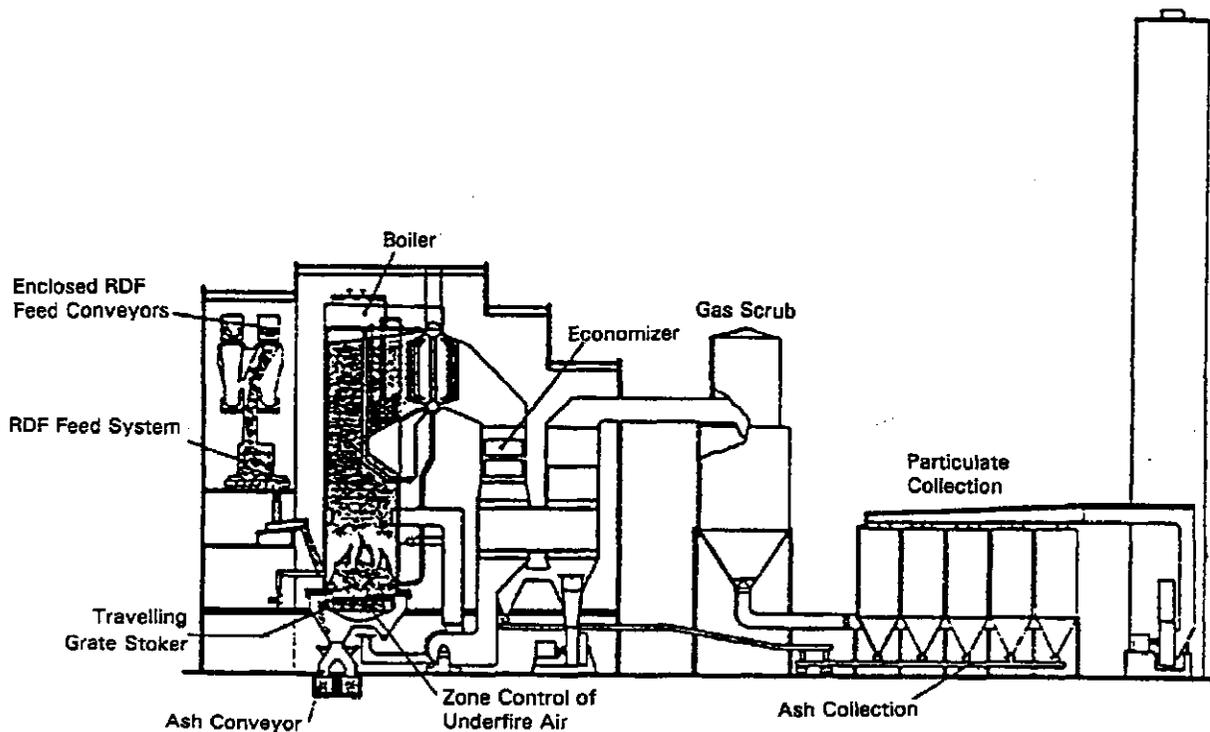
760°C (1200 to 1400°F). One approach to cooling the gas is to arrange for the second gas pass to be an empty, waterwall-lined chamber (see Figure 6.2), or to contain evaporator elements. The first heat transfer tube bundle in the third pass encountered by the flue gas is the final superheater which, in modern designs, is arranged for parallel flow, and reduces the flue gas temperature from about 650°C (1200°F) to about 600°C (1112°F). The tube material is mostly carbon-steel, but higher alloys may be used for the leading tubes where the gas entering the tube bank may attain temperatures higher than desired. The next heating surface is the primary superheater which also is fabricated from carbon steel, and which reduces the flue gas temperature from 600°C to about 450°C (842°F). The fourth pass contains the economizer where the flue gas temperature is reduced to about 230°C (446°F) before the flue gas enters the gas cleanup system.

In general, corrosion damage has been experienced in newly erected mass-burn plants after a few thousand hours of operation. Only a few cases have been reported where increased corrosion occurred after many years of damage-free operation. The most critical areas for fireside corrosion appear to be the waterwalls in the combustion chamber (especially when the SiC coating has been lost, has not been applied, or does not extend to a sufficient height), and the first convection-heated tube banks, especially superheaters exposed to the highest gas temperatures. No obvious correlation has been noted between the design steam parameters and the occurrence of corrosion. However, there does seem to be some correlation between increasing tube surface metal temperature and increasing corrosion, as expected since corrosion processes are thermally-activated. Where accelerated corrosion is observed, the corrosion rates are nearly always very high (Reichel, 1989), around 500 to 1,000 nm/hr (172 to 345 mil/yr).

### **6.1.2 Design of RDF Plants**

The design of boilers used to fire RDF usually has been based on that of stoker-fired boilers used with coal; the superheater is located above the nose at the top of the combustion zone, and the steam generator and economizer are contained in a single convection pass, as indicated schematically in Figure 6.3. The use of an essentially standard boiler design may reduce the initial cost of the unit, but the relatively small size of the furnace zone (compared, for instance to units designed for mass-burning) requires that attention must be given to maintaining good heat absorption in the waterwalls, so that the flue gas temperature at the entrance to the superheater is acceptably low. For this reason, SiC lining of

the lower waterwalls generally is not practiced. Experience with RDF-fired boilers has been that some have suffered furnace wall wastage and tube failures after very short operating times, in some cases within the initial 2,000 hours to one year of operation. Depending on the boiler and location within the furnace, corrosion rates up to 913 to 1,370 nm/hr (315 to 472 mil/yr) have been measured. In most boilers, waterwall corrosion has resulted in the application of a weld overlay of a corrosion-resistant nickel-chromium alloy, Alloy 625 (61Ni-21.5 Cr-9Mo-5Fe-3.6 Nb-0.4Ti-0.4Al-0.1Si-0.05C) over a significant area of the lower and, in some cases, the upper waterwalls.



**Figure 6.3 Schematic elevation of the RDF boiler design used at Hartford, Connecticut. Used by permission of the Connecticut Resource Recovery Authority.**

## 6.2 Combustion Zone Problems

The major factors that contribute to the substantial metal wastage experienced in both waterwalls and convective passes of WTE boilers include (Stanko, 1991): feed stock composition, design features, and operating conditions such as temperature, velocity, and gas/solids composition. Chlorine-containing species are held to be largely responsible for the rapid wastage, although attack by sulfatic deposits also is possible in the high-temperature regions.

On bare waterwalls, tube failures typically have occurred just above the stoker, or in the vicinity of over-fire air ducts or ports. In addition, the corrosion effects are exacerbated by erosion from the locally high flue gas or over-fire air velocities. Common characteristics of corroded waterwall tubes are (Reichel, 1989):

- (1) the iron oxide formed on the tube is non-adherent, porous, and laminated,
- (2) the quantity of corrosion products remaining on the tube wall is only a small fraction of the total corroded metal, and
- (3)  $\text{FeCl}_2$  is observed in the innermost layer of corrosion products in direct contact with the uncorroded metal.

French (1991) categorized the ash deposits on the waterwalls as having two distinct layers: an outer, soft, friable layer containing carbon, sulfur, and chlorine, and an inner, dark or black layer containing much higher levels of carbon and chlorine, as well as Na, Zn, and Pb. Solution of the inner layer in water usually results in an acid pH, indicating the acidic nature of the chloride deposits. The inner layers are easily scraped off the tubes, indicating a less protective scale than the iron oxide formed under air-oxidizing conditions. The presence of carbon and sulfides within both layers indicates that poor combustion was occurring near the walls, resulting in reducing conditions and possibly an increased heat flux and the presence of aggressive species. Chemical and spectrographic analyses of waterwall deposits led French (1991) to suggest the following scenario::

- strongly reducing conditions exist adjacent to the furnace wall, at least on the micro environment scale,
- $\text{HCl}$  and/or  $\text{Cl}_2$  migrates to the tube surface and forms an iron chloride as a corrosion product, thus the wastage is a chlorination reaction,
- the presence of Fe, and Na, Zn, and sometimes Pb suggest the formation of mixed chlorides and low melting point chlorides, and
- the cation mix of the leachable chlorides from the inner layer show mostly Na, with some Fe and no Zn. Lead oxide is not very soluble in water, so would not show up in this test, whereas  $\text{ZnCl}_2$  is soluble, and was missing.

The appearance of the corrosion wastage beneath the deposits is of a fairly uniform attack, usually with no evidence of, for instance, deep pitting or circumferential grooving. Maximum wastage

occurs typically toward the midpoint of the fire-side surface of the tube, which is the hottest portion of the surface.

The available information led to the suggestion (French, 1991) that there are two possible corrosion mechanisms that could account for the rapid wastage of carbon steel waterwall tubes, which are:

- (1) Gas-phase chlorination: strongly reducing conditions exist in the flue gas, so that sulfur is present as  $H_2S$  and iron sulfide scales form rather than iron oxide. These scales are inherently more porous and less protective than oxide scales, and HCl more easily attacks the sulfides to form iron chlorides as a corrosion product. Reducing conditions are essential for this mechanism to proceed by the formation of iron chlorides.
- (2) Liquid ash corrosion: the presence of chlorides in the deposits leads to the formation of low-melting point liquids along the tube surface that may contain Zn, Pb, Fe, and Na chlorides. These liquids would be expected to dissolve any protective iron oxide, leaving bare steel to be corroded by HCl.

Where the main form of corrosion is from gas-phase attack, the generally-accepted threshold temperature below which chlorine-induced corrosion is minimal (Stanko, 1991) is  $232^{\circ}C$  ( $450^{\circ}F$ ). Since waterwall tubes typically operate with metal temperatures between  $260$  and  $315^{\circ}C$  ( $500$  and  $600^{\circ}F$ ), corrosion from gaseous chlorine species is possible in locations exposed to reducing conditions. In the liquid ash-type of attack, the temperature at which accelerated corrosion occurs depends on the melting temperature of the compound, or mixture of compounds, promoting the corrosion. Vapors containing chlorine compounds tend to condense at or near waterwall tube metal surface temperatures. Correlation with temperature of the composition of deposits removed from various locations in a municipal solid waste combustor was found to be consistent with the notion that deposits formed at lower temperatures are richer in the more volatile compounds such as chloride, while deposits formed at high temperatures are proportionally richer in lower vapor pressure compounds such as sulfates and fly ash constituents. The presence of chlorine at the metal surface has been a consistent observation in studies involving corrosion in WTE units.

Even if prevailing reducing conditions could be changed to oxidizing conditions along the waterwalls above the grate, the formation of liquid chlorides along the surface of the waterwall tubes still would be possible in the presence of the high levels of chlorine typical in these boilers. Dissolution of the protective iron oxide scale by these liquid species would lead to wastage either by chlorination or oxidation, perhaps even in a fully-oxidizing atmosphere. Simply assuring oxidizing conditions along the waterwalls therefore may not be sufficient to prevent wastage. Recent laboratory tests (Paul, 1993) have shown that both carbon steel and Type 304L stainless steel were severely attacked under oxidizing conditions by molten chloride salt mixtures at 316°C (600°F).

As mentioned earlier, the two main approaches for minimizing corrosion of the lower waterwalls are: protection with a layer of refractory, or the use of higher-chromium alloys, where heat transfer must be maintained. The preferred refractory lining is silicon carbide, usually to a thickness of 2.5 cm (1 inch). The lining usually is applied by trowelling, and is anchored to the walls using a high-density of sleeveless carbon steel pin studs (Strach, 1989, 1993). Calcium-bonded silicon carbide apparently has proved the most durable. Prefired silicon carbide tiles are preferred in Germany, and are increasingly used in the U.S. However, although such linings are effective, refractory maintenance is constant, and there is a loss in overall heat transfer. Certain types of refractory also are prone to slagging (Gursky, 1992), which further reduces heat transfer.

The choice of replacement alloy depends on the circumstance: for new construction bimetallic tubes of ferritic carbon-steel with an outer layer of high-chromium alloy (such as Type 304, 309 or 310 stainless steel) could be considered while, for existing boilers, a weld overlay of Alloy 625, which has a coefficient of thermal expansion close to that of carbon-steel, has been used with good success. The successful application of weld overlay coatings is dependent on achieving good overall cleanliness of the tube (grit-blast to white metal) at the time that the weld overlay is made, to avoid local debonding and small gaps in the weld coverage that could lead to pinhole attack.

Cast high-alloy blocks or refractory shapes have been used along the grate line for protection. These replaceable liners, bolted to the waterwalls, typically extend up to 4 ft. or so above the grate in the charging section, to approximately 1 ft. above the grate at the discharge. The alloys used to fabricate cast grate bars and sidewall plates are typically high-Cr steels such as 25Cr-12Ni, 27Cr-8Ni, and 30Cr-3Ni. These components are exposed to temperatures that vary between 700 and 1000°C (1292 and 1832°F) and to a wide range of corrosive conditions, depending on the composition of the

waste being burned. The two major modes of failure of such heat resistant castings in waste combustors appear to be (Steinkush, 1989):

- (1) cracking, resulting from high-temperature gradients within the castings, and
- (2) loss of wall thickness because of high-temperature corrosion.

This survey indicated that attack of the waterwalls has increased in recent years as two-stage combustion has been introduced to reduce  $\text{NO}_x$  production. These changes have sometimes resulted in the generation of persistent substoichiometric conditions at the waterwalls, which has allowed the reaction of HCl with the  $\text{Fe}_3\text{O}_4$  scale on the tubes to form  $\text{FeCl}_2$ , with acceleration in the rate of degradation of the tubes. Chlorine is the main corrosive agent in roughly two-thirds of the cases, and sulfur is a main corrosive element in the other cases.

The mixtures of sulfates observed in waterwall ash deposits are typically not expected to be liquid at the operational temperature, and appear not to be harmful in the solid state. Pyrosulfates and alkali iron tri-sulfates, which are expected to form melts in the temperature range of interest, are not usually detected in tube deposits, but may be a factor under some circumstances in WTE boilers.

In summary, the countermeasures that have been credited with a good measure of success in preventing corrosion of the waterwalls in WTE boilers include:

- (1) covering with a SiC lining (pre-fired, high-density tiles preferred) applied over studded carbon steel tubes (mass-burn units),
- (2) application of a weld overlay coating of a nickel-chromium alloy, such as Alloy 625, with care to avoid dilution of the nickel content of the alloy,
- (3) avoiding locally-reducing (substoichiometric) conditions at the waterwalls from incomplete combustion or flame impingement by arranging for the introduction of air along the walls (air blanketing), and by providing a high quality of combustion through:
  - redistributing the over-fire air, and
  - controlling the furnace combustion level through control of the moisture level of the refuse feed, and the use of variable gas/oil injection.

### 6.3 Convection Zone Problems

Incidences of high rates of metal loss from superheater tubes have been observed in some boilers after the first 2,000 to 4,000 hours of operation. The tube failures typically occur on the flue gas in-flow side of the final stage superheater, and near the locations of the soot blowers. Maximum tube thinning typically is located on the crown of the tube facing the gas flow. A not unusual scenario for superheater failures starts with the observation of tube thinning on the leading tubes, and may be followed by tube ruptures, with the interval between ruptures decreasing and the number of tubes requiring repair increasing with time.

The upstream side of the corroded tubes typically develop deposit layers of thicknesses ranging from < 1 to 10 mm (39 to 394 mil), which often have a bow-shaped form on the leading tubes. The deposit layers consist of an external layer of mainly alkali and alkaline-earth sulfates (very low chloride content), a layer of iron oxide scale, and an innermost, often laminated layer richer in chlorides. On shutdown, such deposits are typically very non-adherent and tend to easily break away. Such corrosion has been observed in the absence of a reducing flue gas atmosphere; also, there is often evidence of localized wastage which is attributed to erosive attack. The thickness of the oxide scale formed frequently is less than that calculated from the loss of wall thickness, indicating that periodic scale shedding occurs. The innermost region of the deposit/corrosion product which contains chlorine often is iron-chloride ( $\text{FeCl}_2$ ), which forms a thin layer in direct contact with the metal. This layer may be yellow-brown in color and hygroscopic, or dry and honeycombed in structure. The chlorine may be accompanied by Na, K, Zn, alkaline earth, or other metallic elements. In some cases, reducing conditions may prevail during operation when difficulties are experienced in maintaining uniform combustion of the fuel or in ensuring that entrained fuel particles have been completely combusted before they enter the convection zones. Then, the corrosion products consist of the iron oxides lower in oxygen than  $\text{Fe}_2\text{O}_3$ , and sulfides of Fe, Pb, and Zn, in addition to  $\text{FeCl}_2$ .

The thickness of the deposits formed usually does not exceed 0.1 mm (4 mil), and the chemical composition of the deposit can vary over a large range, and can contain complex alkaline and calcium sulfates and chlorides, and Al, Pb, Zn, and Cu as oxide or sulfates. The sequence of events in the corrosion process involving such deposits has been postulated to be as follows (Kautz, 1971; Miller, et al., 1972): potassium (and other alkali and alkaline-earth) chloride and sulfur dioxide in the deposit react with oxygen to produce potassium sulfate and either HCl or chlorine. The liberated HCl/ $\text{Cl}_2$

reacts with the underlying alloy to produce ferrous chloride, which can further react with oxygen to form iron oxide and free chlorine, serving to perpetuate the corrosion process. Factors which accelerate the corrosion were thought to be:

- tube wall temperatures exceeding 350°C (662°F), and
- large quantities of vaporized chlorides reaching the tubes.

Remedial measures involve reducing the temperature of the flue gas before entry into the final superheater, and assuring turbulent conditions in the gas stream to maximize the reaction of the alkali chlorides in the gas stream to sulfates before contacting the hot tube surfaces. Plumley (1991) suggested that the formation of clusters of glowing particles in the flue gas could be minimized by introducing turbulent mixing to ensure complete burnout before the particles enter the superheater; stratified gas flow over the tube banks and the ensuing increase in relative velocity triggers local burnout, which can lead to locally reducing conditions. When these changes cannot be accomplished through modification to the operation of the boiler, design changes are required, such as installing a sufficiently large evaporator section before the final superheater. An evaporator tube section with a steam pressure of 4.6 MPa (650 psig) has a saturated steam temperature of 257°C (495°F), and a tube wall temperature of approximately 268°C (515°F), which is at the lower end of temperature zone in which corrosive attack accelerates. This approach has been used in a number of the RDF boilers in the U.S.

Where it is not possible to install new heating surface to act as screen tubes for the existing final superheater, it may be possible in some boilers to reroute the steam/water flow in the superheater section so that the coolest tubes contact the hottest gas. An example of this principle was the conversion of the original final superheater into an evaporator section, and to subdivide the original primary superheater to become the final superheater, as well as the primary superheater, in a German combustor (Schirmer, 1984). This change resulted in a reduction in flue gas temperature from 760 to 600°C (1400 to 1112°F) as it passed through the “new” evaporator, compared to 760 to 675°C (1400 to 1247°F) when the evaporator was connected as the final superheater. The tube wall temperature of the new evaporator was 270 to 275°C (518 to 527°F), compared to 300 to 435°C (527 to 815°F) as the final superheater; the new final superheater had a wall temperature of 325 to 435°C (617 to 815°F), while the flue gas temperature at this location was 450 to 600°C (842 to 1112°F). During 1,200 hours

of subsequent operation, the rate of tube wall thinning was approximately 100 nm/hr (34 mil/yr), which still is not acceptable.

Another approach is to install tubes of corrosion-resistant alloy in those locations prone to attack. A number of boilers in the U.S. have several rows of superheater tubing made from Alloy 825 (Fe-42Ni-21.5Cr-3Mo-2Cu-0.6Mn-0.8Ti-0.3Si-0.03C) which, in the case of the Saugus, MA plant, have given good service for 10 to 13 years. Alloy 825 tubes also have been installed in the most vulnerable areas of the superheater in several of the higher steam temperature WTE plants in the U.S., including Westchester Co. NY (1984), Baltimore, MD (1984), and Millbury, MA (1987), all of which operate with 6.3 MPa (900 psig), 443°C (830°F) steam. No superheater failures have been reported at these sites. Test sections of superheater tubes of other alloys, such as Mannesmann's AC66 (Fe-32Ni-27Cr-0.8Nb-0.08C-0.08Ce), are on trial in several boilers.

Corrosion in the convection zone may be aggravated by erosion from soot blowing, particularly when steam is the cleaning medium. Soot blowing is thought to remove the existing scale/deposit, thus stripping the tube of a potential barrier to the corrosive reaction and exposing fresh metal to attack at higher rate. Tubes adjacent to soot blower lanes have been protected by shields, as in coal-fired utility boilers. Half shields, which cover only one face of the tube, have been used as well as full shields which completely encase the tubes. In many cases, these shields have been made from Type 309 stainless steel, but trials have been made with other alloys, such as Alloy 625 and Alloy 825. The lifetime of such shields is of the order of up to 2 years. Tubular specimens of, for instance, Alloy 625 and Alloy 825, appear to offer significantly longer service life.

In some cases, the superheater tubes have been studded to minimize the loss of protective oxide film due to soot blowing (Nakazato, 1989). Since some of the erosive damage from soot blowing is caused by entrained water droplets from the soot blower itself, improved maintenance of soot blower valves can reduce the tube damage. The use of compressed air-type soot blowers is practical in some applications. Other devices for cleaning tube bundles are in use in some boilers. Low frequency sonic soot blowers have been found to be ineffective on superheaters (Nakazato, 1989), but sonic horns have been used to good effect elsewhere for steam generator banks. Mechanical rapping systems have been found to be very effective in some boilers in Germany (Herrmann, 1988) and in the U.S., especially with superheaters that have vertical tubes. It is claimed that mechanical rapping effectively removes the loose ash deposits without disturbing the protective oxide film on the tubes.

In summary, the remedial measures credited with reducing corrosion of the superheater and other convection pass tubes in WTE boilers include those that:

- 1) Minimize particle carryover from the combustion zone.
- (2) Reduce the temperature of the flue gas entering the convection tube banks to a maximum of 760°C (1400°F). If this cannot be achieved because of furnace size limitations, the use of several rows of screen tubes (evaporator tubes) ahead of the superheater can be effective.
- (3) Reduce the metal/steam temperature of the leading tubes in the first rows that contact the flue gas.
- (4) Protect the first 2 to 4 rows of the final superheater, using devices such as metallic shields or ceramic protective tubes, although these require extensive maintenance to maintain attachment and alignment.
- (5) Replace the upstream rows of superheater tubes with a more resistant alloy, such as Alloy 825.
- (6) Protect areas where directional changes in the flue gas flow occur, usually by shields or refractory coverings.
- (7) Protect tubes adjacent to soot blower lanes predominately using shields.
- (8) Replace soot blowers with mechanical rappers or sonic horns.

#### **6.4 Summary of Main Categories of Boiler Tube Problems**

The purpose of this investigation is the review of information from the WTE industry which has shown that many of the operating WTE plants in the U.S. experience rapid corrosion of the furnace

walls. The corrosion is mostly by molten chloride-rich salts and is often associated with reducing conditions. Furthermore the study indicated that corrosion of the superheater tubes is mostly by attack from HCl-containing oxidizing gas. These forms of degradation are quite different from those commonly encountered in coal-fired boilers.

The descriptions of corrosion problems experienced, together with the review of the state of understanding of the factors affecting corrosion in these systems, suggests the following categorization of major causes of the modes of boiler tube failures specific to WTE boilers, which are taken from the companion EPRI study (Wright, et al., 1994), in which the causes and remedial measures were examined in greater detail. This categorization of the types of failures is based on location in the boiler, since the failure causes depend on tube metal/fluid temperature, flue gas temperature, velocity, and composition, which change with location.

(1) Waterwall Thinning Along the Grate Line occurs in a band on each sidewall at an elevation extending from the top of the grate to the maximum height attained by the fuel bed. The main evidence of this form of wastage is gouging and general damage along the waterwall in line with the surface of the grate. This form of wastage is caused by the heterogeneous nature of the fuel that results in occasional hard objects that are too large to be properly accommodated on the grate, and are dragged along the wall by the motion of the grate. Wastage results from a combination of mechanical damage from components in the waste stream that are in contact with the wall and are dragged along it, and gaseous corrosion from the proximity of the burning fuel to the wall. The products of combustion can be extremely corrosive in this location, since conditions of incomplete combustion and flame impingement may persist for extended periods, so that the combustion gas is locally substoichiometric, and the possible corrosive species include HCl, H<sub>2</sub>S, and condensable salts. The combination of mechanical damage, locally high heat flux, and a corrosive environment can result in rates of metal wastage greater than caused by either source acting alone, most probably because any oxide scale formed on the metal is removed before it can provide protection.

(2) Corrosion by Deposits Containing Low-Melting Point Chlorides and Sulfates may be found on the lower waterwalls, upper waterwalls, and sometimes on the leading tubes of the superheater. The area over which this form of attack has been observed may cover a broad band representing several tubes at a location on the waterwall where the metal temperature exceeds the melting

temperature of the corrosive compounds in question, or may be very localized and affect only a single tube. The root cause of this form of wastage is the deposition on the tubes of mixtures of chlorides that melt at the surface temperatures attained by the tubes. Accelerated thinning of the exposed fireside surfaces of the waterwall tubes is caused by the corrosive action of compounds containing chlorides (and sulfates) of Na, K, Mg, and Ca together with heavy metals such as Sn, Zn, and Pb. These chlorides are derived from the reaction during combustion of HCl from PVC (and NaCl), with the oxides of metals volatilized from the refuse, and arrive via condensation from the combustion gases and/or from direct impingement.

(3) Corrosion by Combustion Gases occurs on the waterwalls and leading tubes of the superheater. Tube thinning is observed, typically under porous and/or laminated, voluminous, poorly-adherent corrosion product scales. On the waterwalls, the metal-scale interface will contain  $\text{FeCl}_2$ , but no evidence of alkali metals or Pb, Zn, or Sn. On the superheater tubes, the metal-scale interface will contain  $\text{FeCl}_2$  and alkali sulfates. The root cause of this form of wastage is the presence of PVC and NaCl in the refuse, the persistence of reducing (substoichiometric) conditions at the furnace walls, and high gas and metal temperatures at the superheaters.

This category of boiler tube failure is different from that caused by combustion gas corrosion in coal-fired boilers to the extent that the ambient gas in waste-fired boilers can contain significant levels of HCl in addition to sulfur-containing species, and the proportion of chlorine- to sulfur-containing species is much higher in waste-fired boilers.

(4) Erosion-Assisted Corrosion usually is confined to the superheater and steam generator tube banks adjacent to ducting walls; near the rear wall of rear pass; next to gas flow path openings; and close to soot blower lanes. The upstream surfaces of tubes have a polished appearance, especially adjacent to flow passages; damage also appears as flat spots on tubes. These areas are relatively clean, that is, are covered by a dust layer rather than the usual deposit. The eroded areas can be easily distinguished after water-washing, since they corrode to a uniform color. Erosion-assisted corrosion results from two different sources: high local gas velocities resulting from the blocking of flow passages by deposits, and the action of soot blowers.

## 6.5 Best Available Fixes for Types of Boiler Tube Problems Encountered.

The measures that are currently in use to minimize fireside corrosion problems involve:

- *Improved combustion:* Relocation of overfire air ports in an attempt to control the combustion conditions so that combustion of the fuel is completed in the lower furnace, and gas stream stratification and local substoichiometric conditions in the upper furnace are minimized. Also, attempts are made to ensure that sufficient oxygen is present along the waterwalls to prevent the development of local substoichiometric zones, in an attempt to reduce the likelihood of the development of locally aggressive corrosion conditions underneath any deposits formed in the upper furnace. It is difficult to make a quantitative assessment of the effectiveness of this approach but, since it addresses the nominal root cause of some fireside corrosion problems, it has the potential to prevent their occurrence. However, although this approach is preferred by some manufacturers (Deutsche-Babcock/American RefFuel, for instance), tube failures from corrosion caused by persistent substoichiometric conditions continue to occur in their boiler designs. (Kalmanovitch, 1995).
- *Refractory coating of the waterwalls:* The application of protection in the form of a coating of SiC refractory appears to be effective in preventing further attack of the protected tubes, provided that the coating is properly applied. The use of SiC coatings has been practiced for at least 20 years in Germany, and application in the form of tiles and special shapes attached by studs is currently preferred. In the U.S., SiC coatings are generally applied by trowelling over studs, although tiles are being introduced. As long as the application is sound, trowelled refractory coatings provide good protection, but can represent a significant maintenance problem; also, the thermal conductivity of trowelled coatings may be very low. A common observation is that severe corrosion occurs on the waterwalls just above the refractory layer, at the point where the flue gas first encounters the bare waterwalls. This is presumably a function of the high flue gas temperature (as a result of reduced heat transfer in the refractory-covered lower waterwalls) and the low waterwall temperature (lower than the temperature of the refractory lining), which leads to

deposition of corrosive species at that location. This corrosion is remedied by extending the refractory, where possible, or installing a weld overlay coating of Alloy 625.

- *Metallic coating of the waterwalls:* A number of sprayed metal coatings have been used in U.S. WTE boilers, with mixed results. In general, such coatings are renewed on an annual basis since they either do not adhere to the tubes, or they corrode and act as sacrificial coatings. In contrast, weld overlay coatings of Alloy 625 have been in service for approximately 10 years, and are credited with drastically reducing waterwall corrosion losses. It is estimated that the corrosion rate of a Alloy 625 weld overlay coating is  $< 17$  nm/h ( $< 6$  mil/yr).
- *Control of tube surface temperature:* Reduction of the temperature of the leading pendant tubes reduces the likelihood of molten phases in deposits. Such reduction may require redesign or repositioning of some of the heat transfer surfaces to ensure that the tubes with the highest metal temperature experience flue gas conditions that are least likely to cause serious corrosion problems. While there are claims that such changes have greatly reduced convection pass tube problems, as recounted in Section 6.3, continuing corrosion has been reported in superheater sections where such precautions had been taken (Schirmer, 1984).
- *Use of high-Cr alloy tubes:* Alloy 825 tubes have been installed in a number of boilers in the U.S. in the leading rows of tubes in the superheater (or screen) where corrosion is a problem, apparently with successful results; Alloy 825 tubes were in service in one boiler for approximately 14 years before being replaced as part of a redesign of the superheater. Type 304 clad over carbon steel also is in service in this application.
- *Modification of tube cleaning practices:* Exacerbation of corrosion through removal of any protective scale along with the deposits, and the introduction of erosion damage through entraining particles in the soot blower stream can be avoided or minimized by modification of the tube cleaning practices. Mechanical shaking or rapping has been shown capable of efficiently shedding deposits without disrupting any protective oxide

scale on the tubes. For best results, the tube banks should be designed to withstand the required level of mechanical impact, and vertically-oriented tubes are preferred. One manufacturer has sufficient confidence in this approach that a redesigned superheater with carbon-steel tubes and an improved mechanical rapping system was used to replace a superheater that contained Alloy 825 tubes and an earlier, lower-intensity rapping system. Where soot blowers must be retained, improved maintenance is required to ensure that the desired steam velocity and direction are obtained, and to eliminate the collection of condensate in the steam lines. The tubes adjacent to the soot blower lanes are usually protected by high-alloy (Type 304 or 309 stainless steel) shields, which require frequent inspection and maintenance.

It is interesting to note that co-firing of RDF with coal (at levels of 10 to 20 percent RDF), even at steam conditions that are higher than those used in the state-of-the-art WTE plants, appears to have encountered few corrosion problems. Based on previous research (Krause, 1986), this improvement is thought to be due to the presence of sulfur in the coal, which affects the stability of the aggressive, low-melting chlorides and effectively eliminates them from the tube deposits. Similarly, blending of the refuse with sewage sludge is known to reduce the corrosion rates in WTE plants (Krause, 1980), presumably through some inhibiting effect of silica.

The most desirable strategy would be to avoid many of the current corrosion-deposition-erosion problems by ensuring that the combustion process was completed and the fly ash solidified before the flue gas encountered any heat transfer surface. Such an approach might imply the use of a well-mixed combustor/reactor, followed by a burn-out chamber in which sufficient cooling of the gas was achieved by heat transfer through, for instance, SiC-lined walls, to lower the flue gas temperature below the dew point of the condensable species responsible for accelerated corrosion, before the flue gas enters the main radiant heat transfer section. This is the approach taken by a number of boiler designers; the fact that some continuing problems are experienced suggests that, if the designs addressed the real root causes, they were compromised in some way; for instance:

- the boiler dimensions may have been restricted because of cost, or

- it may have proven difficult to achieve in practice the degree of control required in the operation of the boiler, or
- changes may have been made in fuel or operating practice (the availability of excess air is limited as a result of NO<sub>x</sub> control, for instance) after the design was frozen, or
- the heterogeneous nature of the fuel and its wide variation in moisture content causes excursions.

#### **6.6 Summary of Causes of Metal Wastage and Remedial Measures Practiced.**

It is generally understood that the waterwall and superheater corrosion problems result from the difficulty of maintaining uniform combustion conditions, and the presence of chlorine, alkalis and heavy metals in the fuel. Corrosion occurs following the deposition of low-melting compounds, usually chlorides, or by direct gas-phase attack. In addition, the damage may be initiated or exacerbated by the removal of normally protective oxide scales by mechanical damage (impact, sliding wear, erosion) by the heterogeneous fuel, or from attempts to clean the tubes by, for instance, soot blowing.

The common factors that underly corrosion in WTE boilers of all designs and operating conditions are the deposition of chloride-containing salts which have melting points below the temperatures attained by the surfaces of the heat transfer tubes, and a high concentration of HCl in the flue gas that traverses the convection bank and can lead to accelerated gas-phase corrosion. Specific salts have melting points in the range 149 to 204°C (300 to 400°F). The temperature-dependence of the vapor pressures of the condensable salts determines where deposition can occur, and the composition of the depositing species. The aim of protective measures is to prevent molten chlorides from contacting the furnace wall tubes by using a cladding of silicon carbide, or a weld overlay of Alloy 625 (or a combination of silicon carbide on the lower walls with overlay above it) to a height at which the gas has been cooled sufficiently (typically to 649 to 760°C/1200 to 1400°F) that the bulk of the condensable chlorides has been deposited. Flue gas temperatures below about 1400°F have been found to reduce the rate of corrosion of superheater tubes; the aim is that deposits on the superheaters should be solid (sulfate-rich rather than chloride-rich) hence unlikely to be corrosive, and to present the lowest possible tube metal temperatures to the gas as it enters the superheater bank to reduce the rate of

gas-phase corrosion (and the rate of molten salt attack in cases where condensable chlorides are carried over).

In general, the older designs of WTE boiler provide insufficient furnace volume to ensure that the combustion process could be reliably completed and the gas cooled below about 1400°F before it enters the superheater tube bank. As a result, deposition of low-melting chloride-rich salts is possible on the furnace walls above the silicon carbide cladding, with the potential for accelerated corrosion. In the worst cases, chloride-rich deposits can form on the leading tubes of the superheater bank, leading not only to rapid corrosion especially where such deposits form on the hottest tubes, but also to the build up of flow-blocking deposits that can lead to localized overheating or erosion. Such deposits also lead to the excessive use of soot blowing, which can exacerbate the localized erosion problem.

Where the furnace volume is undersized, one approach to increasing the heat absorption in the furnace is to lower the grate and extend the waterwall downward. This approach also has been used in retrofitting coal-fired stoker boilers for RDF firing. A further possible approach would be to replace the appropriate area of silicon carbide cement-cladding with prefired silicon carbide tiles; depending on its porosity, the thermal conductivity of silicon carbide cement can range to less than 5 Btu/hrft<sup>2</sup>°F at 316°C (600°F), for instance, whereas for high-density, prefired tiles the thermal conductivity could range up to 20 Btu/hrft<sup>2</sup>°F. Alternatively, low-thermal conductivity silicon carbide cladding could be replaced by weld overlay of Alloy 625, which has a thermal conductivity (at 316°C/600°F) of approximately 8 Btu/hrft<sup>2</sup>°F. Obviously, such a change would depend on a careful comparison of the cost of the replacement tiles or weld overlay with the savings from reduced maintenance of the waterwall and superheater tubes, and of the replaced silicon carbide cladding.

Recent WTE boiler designs incorporate increased furnace volumes and a greater distance from the grate to the top of the furnace zone, providing sufficient residence time for combustion to be completed under most operating conditions before the gas exits the furnace. These larger combustion zones allow silicon carbide cladding to be extended to a sufficient height that the gas temperature is cooled to approximately 954°C (1750°F) or less before it encounters bare carbon steel waterwalls. Also, there is sufficient heat transfer area above the silicon carbide cladding to further cool the gas below about 760°C (1400°F) before it exits the furnace zone. Corrosion of the superheater tube banks is minimized by locating them as far as possible from the furnace zone so that there is increased time for condensable chlorides to be deposited out before the gas contacts the superheater tubes. This arrangement is accomplished through the incorporation of multiple convection passes, with the first

(and second) passes ahead of the superheater bank lined with essentially waterwall tubes. However, even if all the condensable salts are removed from the flue gas, it will still contain gaseous HCl which can accelerate the normal oxidation rate of carbon steel, so that it is also important to minimize the gas and metal temperatures. The practical approach is to arrange for the steam flow in the superheaters to be counter to the flue gas flow, so that the coolest tubes encounter the hottest gas. Deposits that form on the convective heat transfer surfaces are removed by mechanical rapping, instead of soot blowing. The superheater tubes are oriented vertically, and a robust tube bundle configuration is used to allow high-intensity rapping.

Further increases in boiler steam pressure and final temperature are desirable to increase the cycle efficiency. The records available from WTE units were insufficiently detailed or complete to allow any attempt to correlate corrosion with steam temperature. Because high-temperature corrosion is a thermally-activated process, increased temperatures will undoubtedly increase the potential for accelerated corrosion rates. Increased steam pressure will increase the maximum temperature attained by the waterwall tubes, which will lead to an increase in the corrosion rate even if the deposition of molten chlorides can be prevented by the modifications discussed above. Similarly, increasing the final steam temperature will increase the inherent corrosion rate of the final tubes of the superheater. For the waterwall tubes, reliable information on the temperature-dependence of corrosion of carbon steel and of Alloy 625 is needed to quantify the likely increase in rate of tube metal loss. For higher-temperature corrosion-resistant superheater tubes, similar corrosion data are required for the candidate alloys, which include: Alloy 825, Type 304 stainless steel, Sanicro 28, and Alloy 625. A Japanese effort to increase the efficiency of WTE plants includes a significant alloy development effort for superheater tubes. A further consideration is that, if upsets in the combustion process occur, there is the chance that chloride-rich deposits will be formed in the superheater. The increased corrosion rates possible at higher metal temperatures require that some efforts are made to improve control of the combustion process, such as active control of the distribution of secondary air.

## 7. Economic Impact of Boiler Tube Problems in Waste-Fired Boilers

As of 1993, there were 92 WTE facilities in the U.S. with capacities of 200 tons/day or greater in operation, accounting for approximately 96,200 tons per day of waste, and 24 others in the planning or construction stages, representing approximately 27,000 tons per day of new capacity. The geographic distribution of the operating and planned plants is indicated in Figure 7.1. Of the planned plants for which data were available, 83 percent were mass-burn design (20 plants: 17 waterwall design, 2 rotary, 1 modular), and 17 percent were for burning RDF (3 stokers, 1 fluidized bed). Of these plants, some 35 percent were to be owned by municipalities, and 65 by private companies, whereas all were to be operated by private companies. Figure 7.2 shows the distribution of the number of waste-to-energy facilities planned as of 1993. Most of those planned units are designed or indicated to have steam temperatures between 800 - 849 °F. A few units are planned to have steam temperatures above 849 °F.

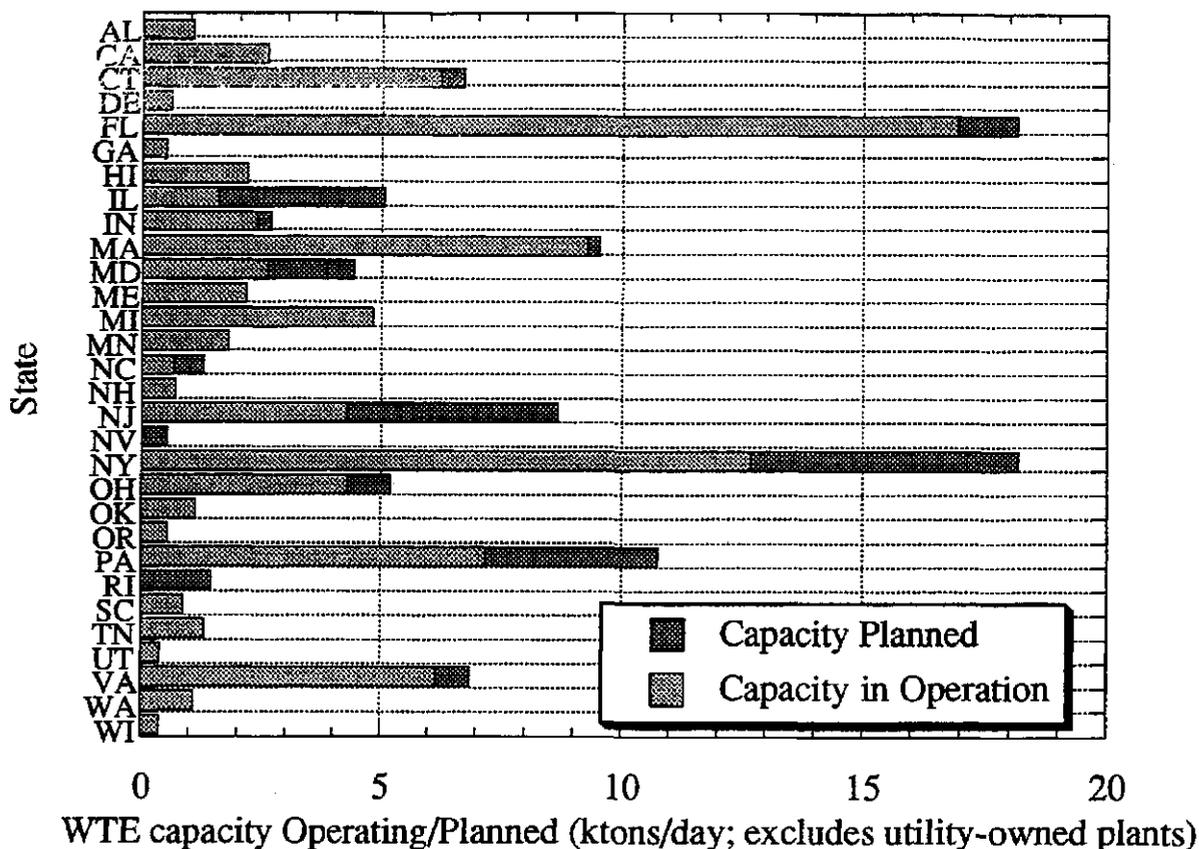
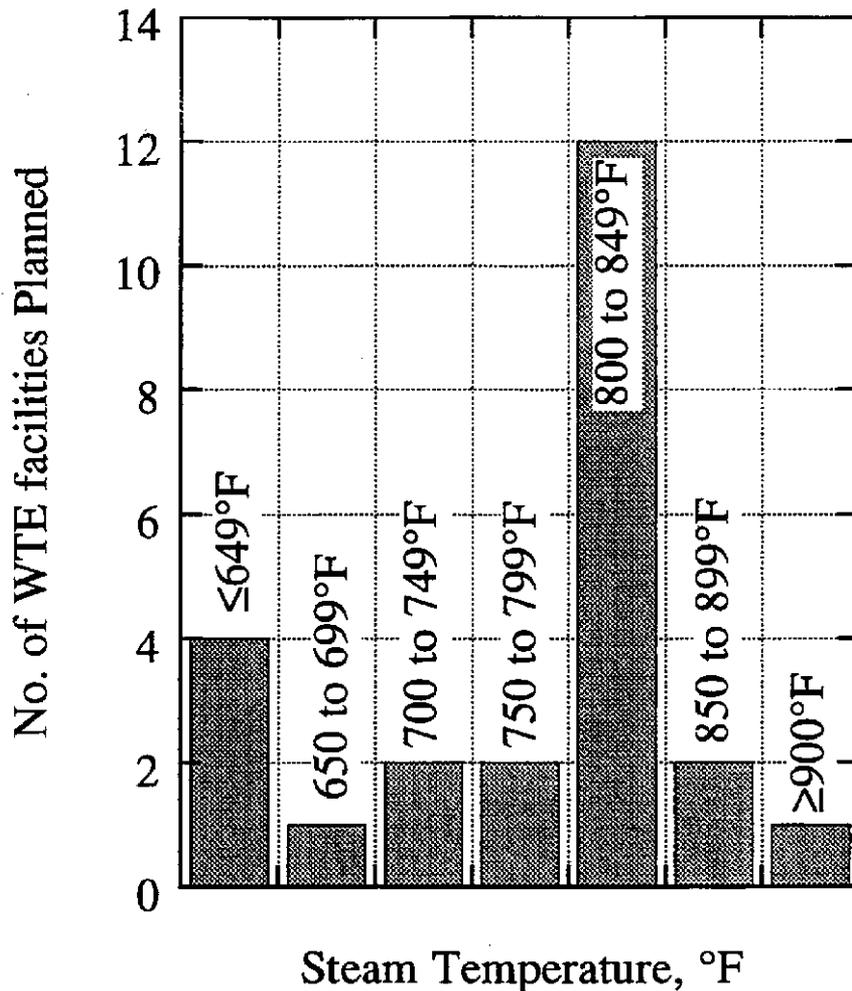


Figure 7.1 Geographical distribution of waste-fired boilers.



**Figure 7.2** Steam temperatures of planned boilers.

Information published by Berenyi and Gould (1993) indicated that the average operating and maintenance cost, based on data provided by 129 WTE facilities, was \$33.58 per ton of refuse for existing plants and was projected to fall to \$27.41 for planned facilities. These costs were exclusive of debt servicing, which cost an additional \$26.51 and \$43.76 per ton, respectively. The average operating and maintenance costs per ton, excluding debt servicing, were lowest for mass-burning units (\$28.88), and highest for modular, mass burning units (\$39.54); the average cost for RDF units was \$38.60. However, the capital costs for modular units were far lower than for other mass-burning units, at \$22.98 compared to \$33.67 per ton (debt servicing costs); the similar cost for RDF units was \$17.91.

The major source of revenue for WTE plants is the tipping fee charged on the delivery of MSW to a WTE facility, which may vary significantly with plant location. Berenyi and Gould (1993) indicated that the tipping fee for existing facilities averaged \$54.84 per ton, and ranged from \$49.49 for RDF units, to \$55.20 for modular units, to \$57.02 for mass burning facilities. The tipping fees also varied with region, from \$43.91 per ton in the south, to \$71.06 in the northeast; three modular units in the west reported an average tipping fee of \$105.31.

The average ash residue disposal fee was \$37.54 per ton; this fee varied with region from \$26.07 in the south, to \$48.15 in the northeast, largely as a result of transportation costs.

Due to of the competitive nature of the WTE business, information relating to the economic impact of boiler tube failures was not readily available, except for a few plants. A large fraction of the current mass-burn and RDF-fired boilers for which information was obtained continue to suffer from corrosion of the waterwalls, which can occur at rates up to 580 nm/hr (200 mil/yr), and lead to tube lives as short as 6 months. An estimate of six unplanned outages per boiler per year is probably reasonable. This form of attack can be quite localized, sometimes affecting only one or two tubes in a given area.

Tube failures in superheaters continue to occur from gas phase or deposit-related corrosion. This is the case even in modern MSW combustor designs. Four such failures per boiler per year are not uncommon. Similarly, deposition in, and partial plugging of, convection pass tube banks result in corrosion and/or erosion failures. Attempts to clean these tubes also are implicated in tube failures, even though in boilers that are equipped with soot blowers, measures to protect adjacent tubes usually have been tried.

An estimation of the costs associated with a given forced outage was made, using some simplifying assumptions, which are outlined below. The cost of a forced outage has the following elements:

- The minimum time required to repair a failed tube, provided that the tube location is accessible and the replacement piece is a stock item, is 12 to 16 hours. This time assumes 4 to 6 hours for the boiler to cool down, 4 hours to make the repair, and 4 to 6 hours for hydro-testing the boiler and heat up.
- Cost of repairing the failure = 2 boilermakers (typically) at  $\$S_b/\text{hr}$  each (with overtime)  $\times t_b$  hours on site per outage + cost of materials. The boilermakers are required to be on-site to make

preparations, to carry out the repair, and to be available through the hydrotest. It was assumed that the labor necessary for providing access to the failure, and performing the boiler operating functions is provided by the normal operating staff, so that their time is not charged to the outage.

- In the worst-case scenario, a plant must produce power or buy replacement power. The cost of replacement power or steam [calculated as the cost of natural gas required to augment the firing of the remaining boiler(s) to maintain output = steam flow to be replaced ( $S_i$  lb/hr) x enthalpy for operating steam temperature ( $H_s$  Btu/lb) x cost of natural gas ( $\$C_{ng}/\text{MBtu}$ ) x duration of outage ( $t_o$ )]/[utilization efficiency ( $e$ )].

Alternatively, if the plant does not have excess capacity and must purchase replacement power, the cost would be:

$M$  MW x  $t_o$  h x  $\$/\text{MWh}$  (assumed to be the same as the price received by the combustor from the sale of electricity).

Assuming that the plant can continue to accept trash deliveries for the duration of the outage, the estimated cost per outage is given by:

$$\$[2 \cdot S_b \cdot t_b + (S_i \cdot H_s \cdot t_o \cdot C_{ng} \cdot 10^{-6})/e] + \text{cost of materials.}$$

or

$$\$[2 \cdot S_b \cdot t_b + M \cdot t_o \cdot P] + \text{cost of materials}$$

Major differences in cost among outages caused by failures in the furnace area and in the generator bank/superheater sections of a boiler can result from the difficulty of access to the location of the failure, and so will be reflected mainly in the values of  $t_o$  and  $t_b$ . Waterwall failures typically are more readily accessible than failures in the pendant or convection section tube banks. For a waterwall failure at a hypothetical plant with a capacity of 2250 ton/day (3 boilers, each producing 168,000 lb/hr steam/54 MWe net at 6.3 MPa/900 psig, 454°C/850°F), and using values of:

$$T_f = \$55/\text{ton}$$

$$F_i = 31.25 \text{ ton/hr}$$

$$t_o = 12 \text{ hr (considered the minimum time needed to repair a waterwall leak)}$$

$$S_b = \$50/\text{hr}$$

$$t_b = 16 \text{ hr}$$

$$S_i = 168,000 \text{ lb/hr}$$

$$H_s = 1,353 \text{ Btu/lb}$$

$$C_{ng} = \$2.00/\text{MBtu}$$

$$e = 40 \%$$

$$M = 18 \text{ MW}$$

$$P = \$80/\text{MWh}$$

the minimum cost per outage is estimated to be \$15,238 to \$18,880 + cost of materials. Based on discussions with WTE plant personnel (but undocumented), a reasonable estimate of the number of unplanned outages experienced per boiler per year is 6 to 10. In the case where the plant has no reserve trash storage capacity, the loss of income from suspension of trash deliveries would be given by: tipping fee ( $\$T_f$ ) (ton) x feed rate to boiler ( $F_i$  ton/hr) x duration of outage ( $t_o$  hr) and the cost per outage would be increased by \$20,625.

On the basis of a plant with excess trash storage capacity, the minimum annual cost of forced outages is estimated (for 6 outages/year) to be \$274,284 to \$339,840 + cost of materials, or \$0.36 to \$0.45 per ton of waste processed (+ cost of materials). Therefore, using this argument, the elimination of 6 unscheduled outages each year (involving either waterwall or convection pass tubing) for each of the 234 boilers at the 92 facilities operating in the U.S. that have waste capacities greater than 200 tons/day, could save a minimum of approximately  $\$21 \times 10^6$  to  $\$26 \times 10^6$  per year, not including the cost of materials.

Based on the assumptions outlined above, the cost of unplanned outages for plants that can continue to accept waste deliveries during an outage amounts to at least 1.1 to 1.3 percent of the average operating and maintenance costs of a WTE plant. If trash deliveries must be stopped during the outage, this cost rises to 2.6 to 2.8 percent of the average operating and maintenance costs. It should also be noted that a claim made for the more modern waste-fired boilers is that unexpected stoppages caused by corrosion failures are rare. Continuous operation of these units can be maintained between scheduled outages; however, operating personnel are under increasing economic pressure to

increase both throughput and time between scheduled outages. These conditions can result in increased corrosion and forced outages.

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## 8. Research Opportunities

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The basic causes of reduction in boiler tube lifetime in waste combustors are well known in general terms: they are the presence of chlorine, alkali and heavy metals in the fuel that combine to produce low-melting, highly-corrosive deposits on the tubes, and the heterogeneous nature of the fuel that makes it difficult to handle and results in hard to control combustion conditions.

One route to minimizing corrosion in WTE units would be to remove the bulk of the chlorine- and heavy metal-containing waste products from the fuel stream. The processing used in the production of RDF has the potential to separate out some of these waste products. However, RDF processing is viewed currently as being expensive, and mass-burning of waste is the favored approach.

At present, it is considered very unlikely that it will be economically viable to make changes in the content of the waste that could significantly reduce its corrosion potential in WTE units, because of the diversity of the sources of the key corrosive species in the waste. Some changes in the fuel received by WTE boilers could be brought about if, for instance individual combustors refused to accept certain categories of waste, as occurred at the Akron facility where certain industrial solvents were not accepted to avoid explosions (Waste Age, 1984). Benefits from sorting and recycling of plastics to maximize the removal of PVC could remove up to 50 percent of the chlorine from the waste, but it would be impossible to remove the rest, which is present mostly as sodium chloride. Reclamation programs for the removal of metals such as Sn, Pb, and Zn could reduce the amount of very low-melting chlorides formed in the combustor, but it is not known what the lower threshold of these elements should be to significantly decrease the potential for fireside corrosion. Also, implementation of such recycling programs is dependent on the cooperation of the communities concerned, and on the ability of industry to absorb the reclaimed material.

The implementation of engineering solutions to corrosion problems in WTE plants has been successful in that modern plants operate routinely despite the problems. Nevertheless, the same kind of corrosion problems are repeatedly encountered, which suggests that the real causes are not being addressed, and that the solutions applied provide a way of managing the problems. Solutions that address the true causes, and which can be used to devise permanent remedies, require a detailed

understanding of the processes that occur in the fireside circuit of WTE units. Translating the present understanding of the mechanisms of corrosion in chloride-containing gases and molten salts to operating WTE systems will require a significant effort. There is, for instance, a need for more detailed knowledge of the corrosive conditions and processes involved in specific locations in the WTE system before more durable solutions to the fireside corrosion problems can be devised. These and other needs are addressed in the following sections.

## **8.1 Research Opportunities for Industry**

### **8.1.1 Improved Documentation**

The generation of a realistic estimate of the extent to which problems with thinning or failure of boiler tubes are reducing the cost effectiveness of the operation of WTE units requires information that often is not published, or is considered confidential. Since there is currently no organization that is charged with advancing the generic technical needs of the WTE industry, there is no centralized or authoritative source of information that could be used by the industry to help itself. One approach to establishing such a resource would be to invite all the major owners and operators of WTE boilers to cooperate in an effort to assemble, as a first step, a record of the number and types of fireside tube problems that have led to unscheduled stoppages. An independent body such as the ASME might act as a focus for this information, which would be handled in such a way that the source was strictly anonymous.

In the electric power industry, this type of reporting is made annually to the National Electricity Reliability Council (NERC); recently (1988) a more detailed reporting system which involves a categorization of boiler tube failures and permanent solutions based the identification of the root cause, was implemented in a number of U.S. boilers. The result of implementing these procedures is that the availability loss of the participating boilers has dropped from the national average value of 2.6 to 2.7 percent to 1.7 percent (with a best value of 1.4 percent, Dooley, 1991). The two major ways in which this scheme has been effective have been the virtual elimination of repeat failures, since the remedial measures address the root causes of the problems and an increase in the accuracy with which failure types, and causes, have been recognized by maintenance engineers through the use of a working manual of the categorized failure types. The net result has been a more rapid identification of the

causes of problems, and longer-lasting solutions. Although the causes of the tube problems that currently are the most prominent in WTE boilers are different from those in coal-fired boilers, the same type of approach would be expected to have a significant impact on reducing the unexpected failures, hence loss of revenue in WTE units.

One of the first efforts proposed would be the setting up of a recommended standardized method protocol of reporting the types of problems that cause unscheduled outages in WTE boilers. This would be an opportunity for a group to develop reporting methods and root-cause analysis/repair/prevention procedures for WTE boiler tube failures. A model for this approach is contained in the reporting system established for U.S. utility boilers (Lamping and Arrowood, 1985; Dimmer, Lamping and Jonas, 1989). This model has proved to be effective in the understanding of the root cause of failure and development of corrective or preventive programs.

### **8.1.2 Control of the Combustion Process**

Some modification of the corrosive environment can be accomplished if reasonable control of the conditions in the combustion zone can be maintained by, for instance, increased turbulence so that the locations of zones where complete and incomplete combustion persist are relatively stable. In such circumstances, the predominant corrosive environment as a function of location in the boiler could be better defined, which would greatly assist effective alloy selection and utilization. Reconfiguration of the combustion zone to increase turbulence can be considered. Some flexibility in the amount and location of overfire air also could assist in improving the uniformity of combustion, and in ensuring that the fireball was contained in the lower regions of the furnace. One approach to providing such flexibility could be through the use of flame monitoring devices inside the furnace zone, with feedback to control the amount and/or location of underfire and overfire air to ensure that combustion was as uniform as possible.

There may be developments that can be transferred from ongoing research, such as that to monitor specific species in the stack gas from the incineration of hazardous waste, and to use a feedback control system to modify the combustion process to maintain the concentration of the given species below set limits (private communication from Dr. C. F. Holt, Midwest Research Institute, 1993). Similarly, it may be possible to analyze the levels of specific components of the fuel in real time to adjust the combustion parameters by, for instance, changing the grate speed or the ratio of

under-fire to over-fire air. Developments in defense-funded combustion and propulsion programs (see, for instance, Oldenberg, 1989) have resulted in sensors for specific gas-borne species relevant to corrosion reactions. These sensors may have potential in monitoring or controlling the combustion processes in WTE units.

### **8.1.3 Definition of Conditions at Tube Surfaces**

There is a need for detailed information on the conditions actually experienced at the tube surface as a function of location in the combustor and of operating conditions. Such information would be useful to the industry in general, and would form the basis for supporting laboratory work. A means of generating this information would be to implement a program at an operating MSW combustor to monitor the conditions experienced by the lower and upper waterwall and superheater tubes while controlled changes were made in the operation of the combustor. Of course any modification to the combustors and its operation must be performed under the permit restriction. This activity should preferably involve expertise from specialist organizations and academia that has access to the types of instrumentation best suited to the specific tasks. This approach also is addressed in Section 8.2.

## **8.2 Research Opportunities for Academia**

There are two main routes to reducing the rates of tube metal loss due to corrosion: the first is to modify the corrosive environment, and the second is to use more corrosion-resistant alloys. A factor that is exacerbating the corrosion problem is the trend to increasing outlet steam pressure and temperature of WTE units, which leads to increased tube metal temperatures, and thereby increases the range of salts that will be molten, hence corrosive. Because of the range of corrosive environments possible in waste-fired boilers, which may include oxidizing or reducing gas mixtures with chlorine- and sulfur-containing compounds present as gaseous or condensed species, it is unlikely that any single alloy will provide the maximum corrosion resistance under all conditions. The approach to be taken for alloy development should, therefore, be guided by a definition of the types of conditions expected at specific locations, or by specific components, so that the alloy requirements for corrosion resistance in those conditions can be addressed.

### **8.2.1 Definition of the Corrosive Environment**

Definition of the conditions experienced at specific locations in a WTE boiler is not an easy task, and will require a concerted effort involving sampling of the local gaseous/vapor/particulate environment, and of deposits. There are several conventional and experimental techniques available for making the necessary measurements, such as electrochemical probes (see, for instance, Whitlow, et al., 1991), but most of these are research tools, so that their use probably will require cooperation with specialist organizations.

A near-term need is for a means of monitoring to detect high-temperature furnace exit temperatures (or other parameters), to provide a means of alerting the operators to take action to avoid subjecting the convective pass to a corrosive environment.

Measurements to characterize the corrosive environment should be made in units that employ different heat absorption rates in the furnace, and different superheater designs or locations. These differences would allow the relative effects of gas and metal temperature, and of residence time in the combustor on the local corrosive environments to be analyzed. Suggested candidate units are: an RDF-fired unit with the superheater located at the furnace nose, and a MSW-fired unit with the superheater located much further away from the furnace.

### **8.2.2 Alloy Development**

The major areas for research related to alloy development are concerned with the definition of the alloying requirements for improved corrosion resistance to the specific conditions experienced at the furnace wall and in the convection zone. For example, there is a need to understand the conditions that cause accelerated corrosion immediately above SiC linings or high-alloy overlays on the upper furnace wall. In addition, research is needed to explore the temperature-dependence of the corrosion behavior of currently-used alloys and corrosion-resistant alternatives so that better informed materials selection in terms of cost effectiveness is possible. Increasing the outlet steam temperature of WTE plants also is the goal of a program being conducted by the New Energy Development Organization (NEDO) in Japan (private communication, 1994); that program is actively developing high alloys for

use in the final stages of the superheaters. Alloys with improved corrosion resistance could be used to increase the tube lifetimes in current boiler designs, provided they prove cost-effective.

The Japanese (Otsuka, et al., 1993) have suggested that the deposits responsible for much of the high-temperature fireside corrosion in their waste-fired boilers can be classified as either chloride-rich, or sulfate-rich. Translation of Japanese data to U.S. WTE units may not be straightforward, since the maximum steam temperature of current Japanese WTE units is significantly lower than for U.S. units (typically less than 300°C/572°F). It is likely that in U.S. waste-fired boilers, chloride-rich deposits may be representative of the conditions at the lower furnace wall, whereas sulfate-rich deposits may be representative of the upper furnace wall and superheater conditions. The combination and total content of the key corrosive species (chlorine, sulfur, alkali metals, Sn, Pb, Zn) depend on the fuel, and definition of the appropriate range of components in deposits derived from combustion of U.S. MSW will require care, since sampling of deposits remaining after shut down of the plant can give quite erroneous results. The Japanese work indicated, not surprisingly, that alloy chromium content is important in providing resistance to sulfate-rich deposits; alloys with chromium contents greater than approximately 20 percent gave the lowest corrosion. For chloride-rich deposits, the alloy content of (nickel + cobalt) also was important, with more than 40 percent required for maximum resistance. There also was an indication of a rapid increase in corrosion at temperatures greater than 500°C (932°F), and the suggestion of a “bell-shaped” dependence of corrosion on temperature with a maximum at 550°C (1022°F), but it was not clear if this behavior was connected to the melting point of the deposit constituents. Further work of this type, using deposits, gas mixtures, and temperatures representative of U.S. WTE boiler conditions would be useful in furthering the understanding of the reasons for the good corrosion resistance exhibited by Alloys 625 and 825, and in defining the ranges of conditions in which good corrosion resistance can be expected. The temperature-dependence of corrosion in WTE conditions also is extremely important, since the ability to operate superheater tubes at temperatures above 482°C (900°F) is key to increasing the efficiency of WTE units. The suggestion of a “bell-shaped” dependence requires further exploration and definition.

The first step in an alloy development program should be laboratory tests to determine trends under conditions that properly simulate the key factors of the deposit and gaseous environments. Alloys or alloy types indicated by these tests to show useful improvements over standard materials should be subjected to field tests in which the actual conditions experienced are known and properly monitored throughout the test exposures. Some of the same techniques used to define the corrosive

environment in the boilers prior to the laboratory simulation tests should be employed in conjunction with field tests using probes or tube panels, so that the actual conditions experienced during the trials are known. Such trials should involve not only a boiler manufacturer, but also an alloy manufacturer so that reduction of the technology to practice is facilitated.

### **8.3 Government Involvement**

One of the main functions that government could undertake to spur the development of techniques to increase heat transfer tube lifetime in WTE units is that of initiating programs that could not be considered by the industry itself. As suggested in Sections 8.1 and 8.2, some of the recommended activities involve collaboration between boiler owners/operators and academia or specialty organizations. The following are areas where a central body or group could facilitate research and assist the WTE industry.

#### **8.3.1 Industry-Academia Interactions**

Research projects such as that outlined in Sections 8.1 and 8.2 should be supported. An example might involve an industry-academia consortium, in which representatives of the WTE industry have oversight of the efforts. The industry would ensure that the research addressed the issues most pertinent to its near-term and perceived future needs, and that any simulations of boiler operation were based on realistic parameters. The industrial participation possibly could be through a Technical Steering Committee, which could have the responsibilities of reviewing proposals and overseeing the progress of the selected projects. The same committee also could be charged with setting in motion the actions necessary to define the procedures for implementing an industry-wide failure documentation system (8.1.1).

#### **8.3.2 Technology Transfer**

Research in programs funded at the U.S. National Laboratories (see for instance, Oldenberg, 1989) has resulted in the development of sensors and control systems for combustion. The application of these technologies to combustion emerging units should be explored. This may be an opportunity to

involve old military installations. In addition to improving the control of corrosion, the ability to control stack gas emissions may be improved if the combustion process is more uniform.

Studies of this type are unlikely to be given high priority at present by the WTE industry without external support, given the other demands on available funds. The demonstration of the feasibility of a method of improved combustion control could provide direction for future improvements in plant operation and design.

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## 9. Acknowledgments

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## **Appendix A**

**Questionnaire Used in Assembling Information  
for Individual Waste-to-Energy Units  
and Summary of Data Obtained**

# Municipal Solid Waste/Refuse-Derived Fuel Boiler Tube Failure Survey

## 1. Site Description

- (a) Name of the facility
- (b) Name of contact person(s)
- (c) Location of the facility
- (d) Owner
- (e) Who operates the facility?
- (f) Start-up date
- (g) Number of units
- (h) Manufacturer of:
  - (i) Grate
    - type
    - location of air zones
    - air preheat temperature
  - (ii) Boiler
    - location of superheater
    - location/type of screen tubes
  - (iii) Refuse handling equipment
  - (iv) Ash handling equipment

## 2. Fuel and Fuel Processing

- (a) Source of fuel (city, county)
- (b) Fuel storage capacity
- (c) Fuel combustion capacity - design/actual
- (d) Fuel calorific value—as collected  
—as burned
- (e) Chemical analysis of fuel
  - moisture content
  - ash content
  - plastics content (PVC, other)
  - seasonal variation
- (f) Others—any major changes in fuel/fuel source?  
—when did such changes in fuel occur?
- (g) What size is the fuel?
- (h) What sorting is done?
  - shredding
  - magnetic separation
  - trommels
  - other
- (i) What materials are recovered?
- (j) Other fuels—coal
  - wood waste
  - tires
  - others
  - what proportion?
  - co-fired?



(ii) Start-up & shut-down procedure:

- auxiliary fuel
- unit kept warm on shut down
- nitrogen blanket

(e) Materials of construction & any changes:

(i) Grate

- Initial materials?
- Changes?

(ii) Furnace

- Waterwall tubing alloy?
- How much of the wall is protected with
  - weld overlay
  - refractory
- What overlay is being used?
- Thickness?
- What refractories are being used?
- Any problems with either?

(iii) Superheater

- Tube materials
- Protection used—shields (what type, what alloy?)
  - other

(f) Any design modifications?

#### 4. Boiler Tube Failures (BTF)

(a) How many BTFs per year, or after how many hours of operation

(b) Where do BTFs occur?

- Location in lower furnace wall
- Location on upper furnace wall
- Location on screen tubes
- Location in superheater
- Other locations

(c) Are BTFs Categorized According to EPRI Guidelines? - (Y) or (N)

(d) What is known about BTF Causes?

(i) Failure analysis

- Is analysis done?
- Who does analysis?
- Are reports available?

(ii) Causes of furnace wall problems

- overheating
- flame impingement
- high CO
- poor combustion
- slagging/channelling

(iii) Causes of superheater problems

- overheating
- deposits - - - solid, liquid?
- channelling
- sootblowing
- erosion
- other

(iv) Were any analyses made of:

- fuel

— deposits

— gas

(e) How is economic impact of outage assessed?

—cost of replacement power

—cost associated with loss of revenue

—landfill costs

5. BTF Remedies Applied

- (a) Was remedy based on known root cause?
- (b) Unit de-rated, or combustion/air distribution modified? How?
- (c) Modified cleaning procedures? Schedule?
- (d) Protection added? — overlay
  - shields
  - coatings
  - other
- (e) Design changes needed? — screen tubes
  - other
- (f) New tube materials used?
- (g) Have repeat BTF's occurred in the same locations?
- (h) Have you run any material trials - (Y) or (N)

If (Y):— Do trials involve replacement tubes or probe data?

— Any data on - - - IN 825, IN 625, IN 671, HR 160  
- - - Others?

—Any data on coatings?

—Who is running/ran the trials?

## 6. Emissions Controls

What equipment/procedures are used to meet emissions control requirements?

(a) Opacity                   —limits?  
                                  —equipment  
                                  —problems

(b) Particulate control     —limits?  
                                  —equipment  
                                  —problems

(c) NO<sub>x</sub> control             —limits?  
                                  —equipment  
                                  —problems

(d) SO<sub>2</sub> control            —limits?  
                                  —equipment  
                                  —problems

(e) Halide control         —limits?  
                                  —equipment  
                                  —problems

(f) Dioxins/Furans control—limits?  
                                  —equipment  
                                  —problems

—Others

—Any special problems?

Table A-1. Summary of Data From Questionnaires

Unit No	Problems Reported	Preventative/Corrective Actions Taken			Wastage Rate (mil/yr)		
		Grate	WW	SH	Design Changes	WW	SH
<b>Mass-Burn—Grate-Type Firing</b>							
<i>Steam temperature &gt; 800°F</i>							
1	no accelerated corrosion or erosion of waterwalls or superheater		modified refractory	825 tubing	larger furnace; increased SH tube spacing		
2	refractory spalling; Al on grate; superheater erosion	frequent repairs	replace refractory	825 tubing; limited soot blowing			
3	corrosion of upper waterwalls		625 overlay			≥150	
4	wear/corrosion of grate; waterwall corrosion; fouling/erosion/corrosion of superheater tubes; flame impingement into superheater		added refractory	825 tubing	added screen tubes; improved air distribution; modular SH; rapping; combustion control		>650
5	grate burnout; slagging of refractory; corrosion of waterwalls	adjusted air distribution	combustion control		added filters to protect preheater		
<i>Steam temperature ≥ 750°F ≤ 800°F</i>							
6	corrosion of upper waterwalls, resulting from slagging of OFA nozzles		625 overlay above refractory			≈100	
7	corrosion of waterwalls; corrosion/erosion of superheater		625 overlay	825 tubing; shields of 304, 310, 625, 825	modified over-fire air	≈400	≈200 (≈500 near SB)
8	waterwall corrosion beneath refractory		SiC+625 overlay	825 tubing		—	—
9	waterwall failures by corrosion/erosion in ≈1 yr;		625 overlay; modified OFA distribution			≈120	
10	waterwall refractory loss; superheater corrosion		modified refractory	825 tubing	installed wall soot blowers		
11	reducing conditions/corrosion of WW; deposit-related corrosion of SH		replaced with same, extended refractory	thicker, upgrade	frequent rapping of superheaters	30-50	40-60
12	waterwall corrosion above refractory		SiC+625 overlay	No	revised air distribution in upper furnace	>150	—
<i>Steam temperature &lt; 750°F</i>							
13	waterwall corrosion-water treatment; waterwall corrosion above refractory; SH corrosion, high gas temperatures; Al probs on grate	replace same; CrNi alloy	added SiC; thicker tubes; 625 added above refractory	added OFA; 825 tubing		>150 to 28	>50 (SB)
14	superheater erosion-corrosion (due to sootblowers)			upgraded materials; reduced soot blowing frequency			>360
15	Cl corrosion of upper waterwalls; erosion of SH (due to soot blowers)		extended refractory	reduced SB frequency		≈50	
16	Cl corrosion of screen tubes and convection bank; erosion/corrosion of convection bank			composite 304/SA 192 tubes	Improved rapping system		≈100
<b>Mass-Burn—Rotary Combustors</b>							
<i>Steam temperature &gt; 800°F</i>							
17	waterwall corrosion; molten salt corrosion of superheater					>350	60-270
<i>Steam temperature ≥ 750°F ≤ 800°F</i>							
18	repeated superheater soot blower-related erosion		625 overlay; SiC	added 309 shields			numerous BTFs
<i>Steam temperature &lt; 750°F</i>							
19	soot blower erosion of upper waterwalls and superheater; WW corrosion		625 overlay	shields		30	
20	corrosion/flame impingement of WW; SB erosion/corrosion of SH		castings; 625 overlay	upgraded mats	redesigned superheaters	≈160	≤55
21	soot blower erosion of superheaters		625 overlay; SiC	253MA shields	increased superheater tube spacing		5 BTFs/yr

Table A-1. Summary of Data From Questionnaires

Unit No	Problems Reported	Preventative/Corrective Actions Taken				Wastage Rate (ml/yr)	
		Grate	WW	SH	Design Changes	WW	SH
<b>Mass-Burn—Modular Combustors</b>							
22	corrosion of lower waterwall above refractory; flame impingement on upper waterwall; superheater corrosion		increase height of refractory	thicker tubes; upgrade to T22	modified air distribution		
<b>RDF-Fired Units with Suspension or Grate Burning</b>							
<i>Steam temperature &gt; 800°F</i>							
23	erosion/corrosion of superheater		625 overlay	shields; overlay			<125
24	corrosion of upper waterwall and superheater		625 overlay	shields		>50	
25	upper waterwall corrosion-reducing conditions		625 overlay	shields; 309 overlay; chromizing	modified over-fire air	≈250	
<i>Steam temperature ≥ 750°F ≤ 800°F</i>							
26	erosion/corrosion at lower furnace arch		625 overlay; refractory added			≤125	
27	Al on grate; corrosion of waterwalls	design modifications	825-clad tubes; 625 overlay				
28	corrosion of WW (overheating); SH erosion; SH erosion/corrosion (SB)		625 overlay	SS shields		≈80	≈60
29	waterwall corrosion (reducing atmosphere); slagging of waterwalls		625 overlay		larger furnace; added superheater screen tubes	≈100	
<i>Steam temperature &lt; 750°F</i>							
30	waterwall corrosion; grate probs; fouling of SH; SB erosion of SH	mod. design; reduced Al intake	thicker tubes; metal spray	shields		≤300	
31	wastage of lower waterwalls; corrosion of superheater (overheating)		thicker tubes; 625 overlay	825 tubing	installed SiC, then replaced with 625; reduced soot blowing frequency	≈125	≈400
32	overheating (int. deposits)+corrosion of lower WW; corrosion of SH		625 overlay	increased tube thickness; 825 tubes; cast shields	increased furnace height; added T-couples; added over-fire air levels	80	≈95
<b>Utility Boilers Burning Some Waste</b>							
33	corrosion of lower waterwalls (reducing atmosphere); corrosion of superheater (high gas temperature)		625 overlay	shields; possibly upgrade to SS		≈150	≤60

## **Appendix B**

### **Listing of Waste-to-Energy Units in Operation and Planned in the United States**

Table B-1. Listing of Waste-Fired Boilers Operating in the U. S.

Facility	Plant Name	Plant Location	State	Plant Owner	Developer	Operator	Start	Capacity (yd)		No. Units	Steam Condensate			Output (MW)		Component Manufacturers				Literature Citation	
								nom.	actual		psi	°F	lb/h	nom.	actual	Boiler	Grate	Emissions Equip.	Emissions Controls		
<b>Mass-Burn—Grate-Type Firing</b>																					
<b>Electricity-Only Plants</b>																					
Commerce Refuse to Energy Facility	Commerce	Los Angeles Co.	CA	Commerce R-T-E Auth.	Foster Wheeler	LA Co. Sanin. District	Jan-87	400	380	1	650	750	115,000	10	10	Foster Wheeler	DS	AAF	DS/NOX/BH	Smith/88; Barrett/89; Smith & Lipscomb/89	
Long Beach SE RRF	Long Beach	Long Beach	CA	Southeast R. R. Fac. Auth.	Dravo	Montenay	Aug-88	1,380	1,170	3	650	750	351,510	36	30	Stein	Stein	Flakt/PPS/Exc	DS/NOX/BH		
Stanislaus Co. RRF	Crows Landing	Modesto	CA	Ogden Martin Sys.	Ogden Martin Sys.	Ogden Martin Sys.	Feb-89	800	730	2	865	830	201,000	22.5	17	Zurn	Martin	Flakt/Exc	DS/NOX/BH		
Bridgeport RESCO	Bridgeport	Bridgeport	CT	Connect. RRA	Wheelabrator	Bridgeport RESCO	Jul-88	2,250	2,000	3	850	825	578,000	87	80	Babcock & Wilcox	Von Roll	Wheelabrator	DS/BH	Barrett/89; Smith and Lipscomb/89; White/89	
Bristol RRF	Bristol	Bristol	CT	Ogden Martin Sys.	Ogden Martin Sys.	Ogden Martin Sys.	Mar-88	650	600	2	885	825	72,444	19	13.5	Zurn	Martin	Flakt	DS/BH		
Southeast CT RRF	Preston	Preston	CT	American Ref-Fuel, Inc.	American Ref-Fuel, Inc.	American Ref-Fuel, Inc.	Feb-92	800	522	2	870	842	151,000	17	17	D-Babcock/Riley	D-B/Dusseldorf RG	D-Babcock	DS/BH		
Broward Co. RR (N)	Broward Co.	Pompano Beach	FL	Wheelabrator Tech.	Wheelabrator Tech.	Wheelabrator Tech.	Apr-91	2,250	2,250	3	800	825	573,500	68.5	80	Volund	Von Roll	Wheelabrator	DS/BH		
Broward Co. RR (S)	Broward Co.	Ft. Lauderdale	FL	Wheelabrator Tech.	Wheelabrator Tech.	Wheelabrator Tech.	Jun-91	2,250	2,250	3	800	825	576,700	63.4	57	Babcock & Wilcox	Von Roll	Wheelabrator	DS/BH		
Hillsborough Co. RRF	Tampa	Brandon	FL	Hillsborough Co.	Ogden Martin	Ogden Martin	Oct-87	1,200	1,200	3	600	750	270,000	30	27.5	Riley	Martin	AAF	ESP		
Lake Co. RRF	Okahumpka	Okahumpka	FL	Ogden Martin Sys.	Ogden Martin Sys.	Ogden Martin Sys.	Mar-91	528	449	2	825	830	120,000	14.5	11.5	Zurn/NEPCO	Martin	Joy	DS/BH		
Pasco Co. SW RRF	Spring Hill	Hudson	FL	Pasco Co.	Pasco Co.	Ogden Martin Sys.	May-91	1,050	883	3	885	830	270,900	31	28	Distral	Ogden Martin	Joy	DS/BH		
Wheelabrator Pinellas RR	Pinellas	St. Petersburg	FL	Pinellas Co.	Wheelabrator	Wheelabrator	May-83	3,150	2,835	3	675	750	750,000	82	55.8	Riley	Martin	Wheelabrator	ESP	Turner/84; Geyser/89; Smith/89; Strach/89	
Wheelabrator Tampa-McKay Bay Fa	Tampa	Tampa	FL	City of Tampa	Waste Mgmt	Wheelabrator	May-85	1,000	844	4	650	700	208,400	17	15	Volund	Volund	Smith	ESP		
Haverhill RRF	Haverhill	Haverhill	MA	Ogden Martin Sys.	Ogden Martin Sys.	Ogden Martin Sys.	Jun-89	1,850	1,518	2	885	830	398,000	46	41	Zurn	Martin	ABB-CE	ESP/DS		
North Andover RESCO	North Andover	North Andover	MA	Wheelabrator Tech.	Wheelabrator Tech.	Wheelabrator Tech.	Jun-85	1,500	1,350	2	600	750	344,000	40/32	32	Riley	Martin	Wheelabrator	ESP	Smith/89; Strach/89	
Saugus RESCO	Saugus	Saugus	MA	Wheelabrator Tech.	Wheelabrator Tech.	Wheelabrator Tech.	Oct-75	1,500	1,200	2	650	850	340,000	50	40	Von Roll	Von Roll	Wheelabrator	DS/BH	Hepp/88; Ganesary/87; Harris/87; Smith/89; Strach/89; White/89/Coll	
Wheelabrator Milbury	Milbury	Milbury	MA	Wheelabrator	Wheelabrator Tech.	Wheelabrator Tech.	Sep-87	1,500	1,500	2	900	850	336,000	40	36	Babcock & Wilcox	Von Roll	Wheelabrator	ESP/DS	Gibbs/88; Smith/89; Strach/89; Hepp/92	
Greater Portland RRR	Portland	Portland	ME	Regional Waste Systems Inc.	Regional Waste Systems Inc.	Regional Waste Sys. Inc.	Sep-88	500	500	2	600	750	120,000	13.8	10	Stein	Stein	Belco	ESP/DS		
Hennepin ERF	Hennepin	Minneapolis	MN	Hennepin Energy Rec.	Blount	Ogden Martin	Dec-89	1,200	1,000	2	600	750	350,000	37.5	33	Distral	W&E	R-C	DS/BH		
NHVT SW Project	Claremont	Claremont	NH	Wheelabrator	Wheelabrator	Wheelabrator	Mar-87	200	190	2	600	700	48,200	4.5	3.8	Arn. Schack	Von Roll	Wheelabrator	DS/BH	Hametta/89; Strach/89	
Wheelabrator Env. Co.	Concord	Concord	NH	Wheelabrator Tech.	Wheelabrator Tech.	Wheelabrator Tech.	Apr-89	500	425	2	650	750	135,400	14	12	Babcock & Wilcox	Von Roll	Wheelabrator	DS/BH		
Camden RRF	Camden Co.	Camden	NJ	Camden Co. ERA	Camden Co. ERA	Foster Wheeler	Jul-91	1,050	840	3	650	750	260,400	21	21	Foster Wheeler	DS	Belco	ESP/DS	Maturoy/92	
Essex Co. RRF	Essex Co.	Newark	NJ	Am. Ref-Fuel/Pt. Au. NY&NJ	American Ref-Fuel	American Ref-Fuel	Nov-90	2,250	2,000	3	850	755	633,000	78	68	Riley	Deutsche Babcock	Flakt/D-Babcock	ESP/DS		
Warren ERF	Oxford Twp.	Warren Co.	NJ	Warren Energy Res. Co.	Blount	Ogden Martin	Jul-88	400	450	2	815	750	112,000	13.5	10.5	Distral/W&E	W&E	EEC	DS/BH	Schuetzenuebel/81	
Wheelabrator Gloucester	Gloucester Co.	West Deptford	NJ	Wheelabrator Tech.	Wheelabrator Tech.	Wheelabrator Tech.	Jan-90	575	525	2	650	750	135,400	14	12	Babcock & Wilcox	Von Roll	Wheelabrator	DS/BH		
Adirondack RRF	Hudson Falls	Hudson Falls	NY	Adirondack RR Assoc.	Foster Wheeler	Adirondack RR Assoc.	Feb-92	400	410	2	650	750	140,000	13	11	Foster Wheeler	Detroit Stoker	Belco	ESP/DS		
Am. Ref-Fuel Co. of Hempstead	Westbury	Westbury	NY	American Ref-Fuel, Inc.	American Ref-Fuel, Inc.	American Ref-Fuel, Inc.	Aug-89	2,505	2,505	3	870	842	830,000	72	54	D-Babcock/Riley	Dusseldorf RG	Good/Belco	DS/BH	Gursky/92; DeVincentis/83	
Babylon RRF	West Babylon	Babylon	NY	Ogden Martin	Ogden Martin	Ogden Martin	Apr-89	750	640	2	655	700	185,000	17	14	Zurn	Martin	Belco	DS/BH		
Huntington, NY	Huntington	Huntington	NY	Ogden Martin Sys.	Ogden Martin Projects	Ogden Martin Projects	Nov-91	750	638	3	885	830	225,000	29	21	Distral	Martin	EEC	DS/NOX/BH		
Westchester Co.	Peekskill	Peekskill	NY	Wheelabrator Tech.	Wheelabrator Tech.	Wheelabrator Tech.	Oct-84	2,250	1,890	3	900	830	504,000	60	55.5	Babcock & Wilcox	Von Roll	Wheelabrator	ESP	Hepp/88; Gibbs/88; Smith/89; Strach/89	
Marion Co. Solid WTE Fac.	Brooks	Brooks	OR	Ogden Martin Sys.	Ogden Martin Sys.	Ogden Martin Sys.	Mar-85	550	535	2	655	700	133,448	13.1	11	Zurn	Martin	AAF	DS/BH		
Lanc. Co. RRF	Bainbridge	Bainbridge	PA	Lancaster Co. S. W. M. Auth.	Ogden Martin Sys.	Ogden Martin Sys.	May-91	1,200	1,080	3	865	830	291,000	36	30	Zurn	Martin	Joy	DS/BH		
Montgomery Co. RRF	Conshohocken	Plymouth Twp.	PA	Montenay Power Corp.	Montenay Power Corp.	Montenay Power Corp.	Jan-92	1,216	1,062	2	650	751	324,000	34	29	Steinmuller	Steinmuller	Res-Cottrell	DS/BH		
1-95 Energy RRF/Fairfax Co.	Lorton	Lorton	VA	Ogden Martin Sys.	Ogden Martin Sys.	Ogden Martin Sys.	Jun-90	3,000	2,700	4	865	830	822,504	85	78	Zurn	Martin	Flakt	DS/BH		
Alexandria/Arlington RRF	Alexandria	Alexandria	VA	Ogden Martin Sys.	Ogden Martin Sys.	Ogden Martin Sys.	Feb-88	975	840	3	600	700	255,000	22	19.8	Keeler/DO	Martin	UnitMG	ESP		
Spokane Reg. Solid Waste Disp. Fac.	Spokane	Spokane	WA	City of Spokane	Wheelabrator	Wheelabrator	Nov-91	800	817	2	900	830	222,800	26	22.1	Babcock & Wilcox	Von Roll	Wheelabrator	DS/NOX/BH		
<b>Electricity-Stream Plants</b>																					
Chicago NW, IL	Chicago	Chicago	IL	City of Chicago	City of Chicago	City of Chicago	Sep-70	1,800	1,250	4	275	414	330,000	---	---	Walther	Martin	Roth	ESP		
Baltimore RESCO	Baltimore	Baltimore	MD	Ford Motor Co.	Wheelabrator	Wheelabrator	May-85	2,250	1,947	3	650	750	441,000	60	34	Babcock & Wilcox	Von Roll	Wheelabrator	ESP	Hepp/88; Gibbs/88; Jantzel/88; Smith/89; Strach/89; Gursky/92	
Kent Co. WTE Fac.	Grand Rapids	Grand Rapids	MI	Kent Co.	Ogden Martin	Ogden Martin	Mar-90	625	625	2	865	850	158,000	18.3	15.7	Keeler/DO	Martin	Flakt	DS/BH		
Montenay Glen Cove Corp.	Glen Cove	Glen Cove	NY	City of Glen Cove	Montenay	Montenay	Aug-83	250	225	2	600	490	40,000	2.5	1	Zurn	Morse B.	Belco	ESP		
Walter B. Hall RRF	Tulsa	Tulsa	OK	CIT Group	Ogden Martin	Ogden Martin	Oct-86	1,125	1,060	3	650	700	240,000	16.5	14.5	Zurn	Martin	EnvElem	ESP		
Harrisburg WTE Fac.	Harrisburg	Harrisburg	PA	City of Harrisburg	Ogden Martin	City of Harrisburg	Oct-72	720	620	2	250	505	170,000	8.2	5.25	IBW	Martin	Rossm	ESP	Turner/84	
Foster Wheeler Charleston RR	Charleston	Charleston Co.	SC	Charleston Co./FW	Foster Wheeler	Charleston Co./FW	Nov-89	600	600	2	850	750	164,000	12.8/4.2	10.8	Foster Wheeler	DS	Belco	ESP/DS		
Nashville Thermal Transfer Corp.	Nashville	Nashville	TN	Metro. Gov. Nashville	City of Nashville	Nashville Thermal Transfer	Feb-74	1,120	950	3	400	600	308,000	7.3	2.9	Babcock & Wilcox	DS	AAF	ESP	Turner/84; Ganesary/87; Harris/87; Smith/89	
Jackson City	Jackson Co.	Jackson	MI	Jackson Co.	Jackson Co.	Metcalf & Eddy	Oct-87	200	200	2	615	650	49,600	2	1.7	Riley/Takuma	Riley/Takuma	Research Cottrell	DS, BH		
Mecklenburg County	University City Rf	Charlotte	NC	Mecklenburg County	M. K. Ferguson Co.	MK Environmental	Jun-89	235	165	2	600	750	50,000	5.3	4	Volund	Volund	Schenjot	ESP		
Olmstead County	Olmstead County	Rochester	MN	Olmstead County	Riley Stoker/Takuma	Olmstead County	Mar-87	200	190	2	815	650	50,000	3	2.25	Riley	Riley/Takuma	Belco	ESP		

Table B-1. Listing of Waste-Fired Boilers Operating in the U. S.

Facility	Plant Name	Plant Location	State	Plant Owner	Developer	Operator	Start	Capacity, Yd		No. Units	Steam Condns			Output, MW		Component Manufacturers				Literature Citation	
								nom.	actual		psi	°F	lb/h	nom.	actual	Boiler	Grate	Emissions Equip.	Emissions		
<b>Steam Plants</b>																					
Huntsville Refuse-Fired Steam Fac.	Huntsville	Huntsville	AL	Huntsville S.W. Disp. Auth.	Ogden Martin	Ogden Martin	Jul-91	890	585	2	350	470	172,000	0	0	Zum	Martin	ABB-CE	DS/BH		
Savannah RRF	Savannah	Savannah	GA	Katy-Seghers, Inc.	Katy-Seghers, Inc.	Katy-Seghers, Inc.	Jun-87	500	480	2	650	750	120,000	0	0	Zum	Seghers	EEC	ESP	Beckman/87	
Indianapolis RRF	Indianapolis	Indianapolis	IN	Ogden Martin Sys. Inc.	Ogden Martin Sys. Inc.	Ogden Martin Sys. Inc.	Dec-88	2,362	2,173	3	510	710	500,000	0	0	Riley	Martin	EEC	DS/BH		
Bens Avenue Incinerator	Queens	New York	NY	City of New York	City of New York	City of New York	Jan-64	1,000	800	4	125	350	31,250	0	0	Bigelow/YS	ITG	PPC	ESP		
Davis Co. WTE Fac.	Layton	Layton	UT	Davis Co. SWM & ER Dist	Katy-Seghers, Inc.	Katy-Seghers, Inc.	Oct-88	400	350	2	120	350	110,000	0	0	Zum	Seghers	EEC	ESP/DS	Beckman/87	
Hudson Falls	Washington/Warr	Hudson Falls	NY	Adirondak Res. Rec.	Foster Wheeler	Adirondak Res. Rec.	Jan-92	400	345	2	650	750	115,000	13	11	Foster Wheeler	Detroit Stoker	Belco	ESP, DS		
Hampton/NASA Refuse-fired Gen.	Hampton	Hampton	VA	NASA/City of Hampton	Clark-Kerith	City of Hampton	Oct-80	200	235	2	360	439	98,000	—	—	Keeler	Detroit Stoker	PPC	ESP	Lovelend/83; Turner/84; Musolino/87	
<b>Mass-Burn—Rotary Combustors</b>																					
Bay Res. Mgmt. Center	Panama City	Panama City	FL	Ford Motor Credit Corp.	Westinghouse	Westinghouse	May-87	510	435	2	620	750	88,000	12	10	Deltak	Whouse/O'Conner	EEC	ESP	Whitow/89; Ettehadieh/90	
Duchess Co. RRF	Poughkeepsie	Poughkeepsie	NY	Duchess Co. Res. Rec. Ag.	Westinghouse	Westinghouse	Oct-88	506	400	2	825	700	110,000	9	2.2	Deltak	Whouse/O'Conner	Zum/R-C	DS/BH; DSI		
MacArthur WTE Fac.	Islip	Islip	NY	Islip Rec. Rev. Agency	Montanay	Montanay	Jun-89	518	450	2	600	700	116,000	10.5	8	Deltak	Whouse/O'Conner	Brandt/R-C	DS/BH		
Montgomery Co. (N) RR	Dayton	Dayton	OH	Montgomery Co.	Montgomery Co.	Montgomery Co.	Sep-88	300	255	1	510	650	72,000	6	5.7	Combustion Engg.	Montgomery Co.	UnitMG	ESP		
Montgomery Co. (S) RR	Dayton	Dayton	OH	Montgomery Co.	Montgomery Co.	Montgomery Co.	Aug-88	900	810	3	500	650	240,000	18.8	17.7	Combustion Engg.	Montgomery Co.	UnitMG	ESP/DS		
Delaware Co. RRF	Chaster	Delaware Co.	PA	CT Nat. Bank	Westinghouse	Westinghouse	Apr-92	2,688	2,285	6	675	810	664,972	90	75	Tampala-Keeler	Whouse/O'Conner	Joy	DS/BH		
York Co. RR Center	York Co.	Manchester Twp.	PA	York Co. S. W. & Ref. Auth.	Westinghouse	Westinghouse	Oct-89	1,344	1,100	3	814	800	330,000	35	30.2	Deltak	Whouse/O'Conner	Joy	DS/BH	Whitow/89	
Res. Auth. in Sumner Co.	Gallatin	Sumner Co.	TN	Resource Auth. in Sumner Co.	Resource Auth. Sumner Co.	Resource Auth., Sumner Co.	Dec-81	200	150	2	425	510	50,000	0.5	3.4	O'Conner/Keeler	WH/O'Conner	PPC	ESP	Parker/82; /85; Whitow/86; /89	
<b>Mass-Burn—Modular Combustors</b>																					
Tuscaloosa ERF	Tuscaloosa	Tuscaloosa	AL	Tuscaloosa S. W. Disp. Auth.	Consumat	Tuscaloosa S. W. Disp. Auth.	Feb-84	380	290	2	350	415	55,880	0	0	Consumat	Consumat	PPC	ESP		
Wallingford RRF	Wallingford	Wallingford	CT	Wallingford RR Assoc	CT RR Auth.	Wallingford RR Assoc	Apr-90	420	380	3	650	780	105,000	11	9.3	Zum	Enercon	Procl	DS/BH		
Energy Gen. Fac. at Pidgeon Point	Pigeon Point	Newcastle	DE	United Assoc. of DE/GE	Utd. Power Services Inc./Vicon	Utd. Power Services Inc.	Oct-90	800	546	4	600	700	152,000	13.3	10.5	Am. Schack	Vicon	PPC	ESP	Harriette/89	
Pittsfield	Pittsfield	Pittsfield	MA	Vicon Recovery Assoc.	Vicon Recovery Assoc.	Vicon Recovery Assoc.	Mar-81	240	215	2	200	520	52,000	—	—	Bigelow	Enercon	Utd. McGill	ESP, WS		
Springfield RRF	Agawam	Agawam	MA	Fluor RR of Mass. Ltd.	Vicon Energy Sys.	Vicon Energy Sys.	Aug-88	380	315	3	650	750	85,500	9.4	7.4	Deltak	Enercon	Flakt	DS/BH		
Harford W-T-E Fac.	Edgewood	Aberdeen Prov. Gds.	MD	Waste Energy Partners	N.E. MD Solid Waste Auth.	Consumat	Jan-88	360	327	3	133	340	75,000	0	0	Abco	Consumat	PPC	ESP		
Mid-Maine Waste Action Corp. RRP	Auburn	Auburn	ME	M-MWACorp	American Energy Corp.	American Energy Corp.	Jul-92	200	176	2	625	750	50,000	4.5	3.3	Am. Schack	Laurant Bouillet	Joy Techn.	DS/BH		
New Hanover Co. WTE Fac.	Wilmington	New Hanover Co.	NC	New Hanover Co.	New Hanover Co.	New Hanover Co.	Jun-84	450	380	3	450	650	120,000	7	4	Keeler/Volund	Detroit Stoker	Utd. McGill/Nalco	ESP; DS; NOx		
Long Beach	Long Beach	Long Beach	NY	Catalyst WTE Corp.	Montanay	Montanay	Feb-88	200	170	1	750	490	58,000	4.5	3	Inf. Boilers Works	Morse Boulger	Belco	ESP		
Oneida County	Oneida County	Rome	NY	Oneida County	Clear Air, Inc.	Oneida/Herkimer SW Auth.	Jan-85	200	180	4	250	425	28,000	2.2	1.2	Abco	Clear Air	Utd. McGill	ESP		
Oswego County	Oswego County	Velney	NY	Oswego County	Consumat	Oswego County	Feb-86	200	180	4	265	400	50,000	4	1	Abco	Consumat	Preciptair	ESP		
South Exchange Joint Venture	Hampton	Hampton	SC	Southland Exchange Inc.	Consumat	Southland Exchange Inc.	Oct-85	270	200	2	150	290	45,000	0	0	Vlerson	ConsuSys	ConsuSys	ESP		
<b>RDF-Fired Units with Suspension or Grate Burning</b>																					
Exeter Energy Ltd. Ptnrshp	Exeter	Sterling	CT	Oxford Energy Ltd. Ptnrshp.	Oxford Energy Co.	CMS Gen.	Oct-91	300	285	2	1000	930	240,000	30	28	Zum	Lambion Stoker	GEES/Nalco	BHWS/NOx	Makansi/92	
MID-Connecticut	Hartford	Hartford	CT	Conn. Res. Rec. Auth.	ABB-CE	Ogden Martin Sys.	Oct-88	2,000	2,300	3	880	825	693,000	90	88.5	Combustion Engg.	Combustion Engg.	ABB-CE	DS/BH	Boley/89; /90; Plumley & Lewis/91; Davis/92; Plumley/93	
Dade County RF	Dade Co./Miami	Miami	FL	Dade Co.	Montanay	Montanay	Jan-82	3,000	3,000	4	825	721	720,000	77	62	Zum	Zum	Flakt	ESP	Davis/92; Zili/92	
N. Co. Region RR Proj	West Palm Beach	West Palm Beach	FL	S. W. Auth. of Palm Beach C	Babcock & Wilcox	Babcock & Wilcox	Nov-89	2,000	2,000	2	750	750	532,000	60	49	Babcock & Wilcox	DS	Joy/WE	ESP/DS	Burnham/89; O'Conner/82	
H-Power	Ewa Beach	Honolulu	HI	City of Honolulu/Ford Credit	ABB-CE	Ogden Martin Sys.	May-90	2,160	1,740	2	900	850	508,000	57	48	Combustion Engg.	Combustion Engg.	ABB-CE	ESP/DS	Boley/88	
Haverhill Lawrence RDF Fac.	Haverhill	Lawrence & Haverhill	MA	Ogden Martin Sys., Inc.	Ogden Martin Sys., Inc.	Ogden Martin Sys., Inc.	Sep-84	710	450	1	600	750	185,000	21	17	Babcock & Wilcox	DS	Belco	ESP	Burnham/89	
SEMASS	Rochester	Rochester	MA	SEMASS Partnership	Energy Answers Corp.	Bechtel	Jan-89	1800 (to 1,800)	1,800	2	650	750	560,000	52 (to 78)	45	Riley	Riley	Joy	ESP/DS	Hohman/89; Turner/90; Davis/92	
Maine Energy recovery	Biddeford	Biddeford	ME	KTI Energy Inc.	KTI Energy Inc.	KTI Energy Inc.	Apr-87	700	607	2	675	760	210,000	22	20	Babcock & Wilcox	DS	General Electric	DS/BH	Burnham/89	
Penobscot ERF	Orrington	Orrington	ME	KTI Energy Inc.	KTI Energy Inc.	GE Co.	Apr-88	750	750	2	650	750	250,000	25.3	21	Riley	Riley	General Electric	DS/BH		
Greater Detroit RRF	Detroit	Detroit	MI	Phillip Morris Cap. Corp.	Greater Detroit R. R. Auth.	ABB-CE	May-89	4,000	1,800	3	800	825	688,000	65	—	Combustion Engg.	Combustion Engg.	ABB-CE	ESP	Boley/89; Davis/82	
Kodak RRF	Rochester	Rochester	NY	Eastman Kodak	Eastman Kodak	Eastman Kodak	Jan-70	150	119	1	400	550	150,000	—	—	Combustion Engg.	Combustion Engg.	Wheelabrator	ESP	Blakeley/90	
Occidental Chem. Corp. WTE Plant	Niagara Falls	Niagara Falls	NY	Occidental Chem. Corp.	Occidental Chem. Corp.	Occidental Chem. Corp.	Dec-80	2,000	1,800	2	1000	700	480,000	50	30	Foster Wheeler	DS	Belco	ESP	Makansi/84; Morello/91; Smith/89; Tracy/91	
RDF-Steam Gen. Fac.	Albany	Albany	NY	State of New York	City Hempstead/State of NY	State of New York	Feb-82	600	500	2	250	510	200,000	0	0	Zum	Zum	PPC	ESP		

Table B-1. Listing of Waste-Fired Boilers Operating in the U. S.

Facility	Plant Name	Plant Location	State	Plant Owner	Developer	Operator	Start	Capacity t/d		No. Units	Steam Condns			Output, MW		Component Manufacturers				Literature Citation
								nom.	actual		psi	°F	lb/h	nom.	actual	Boiler	Grate	Emissions Equip.	Emissions	
Akron Recycle Energy Sys.	Akron	Akron	OH	City of Akron	City of Akron	WTE Corp	Jun-84	1,100	965	3	580	478	280,000	4	--	Babcock & Wilcox	DS	UOP	ESP	Makansi/84; Ganesan/87; Burnham/89
City of Columbus SW Reduction Fac.	Columbus	Columbus	OH	City of Columbus	City of Columbus	City of Columbus	Jun-83	2,000	1,800	6	700	700	700,000	40	34	Babcock & Wilcox	DS	Balco	ESP	Moats/88; Burnham/89; Davis/92
SETEP	Portsmouth	Portsmouth	VA	Southeastern Pub. Serv. Auth.	Heil	Southeastern Pub. Serv.	Jan-88	2,000	1,845	4	850	700	375,000	40	36	Combustion Engg.	Combustion Engg.	General Electric	ESP/BH/DS	Turner/84; Davis/92
<b>RDF-Fired Fluidized-Bed Combustors</b>																				
W. Lake Superior Sanit. Dist.	Duluth	W. Lake Supr. Sntn. Di.	MN	W. Lake Superior Sanit. Dist.	Consoer Townsend/Beloit Rac.	W. Lake Superior Sanit. D.	Mar-81	400	300	2	250	400	36,000	--	--	Deltak	Copeland	Emrol	WS	
Tacoma	Steam Plant#2	Tacoma	WA	Tacoma Pub. Util.	--	Tacoma Pub. Util.	Aug-81	300	200	2	400	750	528,000	50	43	Energy Prod. Idaho	Energy Prod. Idaho	Brandt	BH	Hughes/81
La Crosse Co.	French Island	LaCrosse	WI	Northern States Power	Northern States Power	Northern States Power	Apr-88	400	225	2	450	750	300,000	30	28	Foster Wheeler/Edg	EPI	ComPow	GB/LI	Barrett/89; Smith & Lipscomb/88
<b>Utility Boilers That Have Fired Some Waste</b>																				
<b>(a) In Operation</b>																				
City of Lakeland	McIntosh#3	Lakeland	FL	City of Lakeland	City of Lakeland	City of Lakeland	Sep-82	300	275	1	2400	1005	2,300,000	364	335	Babcock & Wilcox	Babcock & Wilcox	Babcock & Wilcox	ESP/WS	Hiers/82; McGowin/82; Garing/89
Ames RR Proj.	Unit#5	Ames	IA	City of Ames	City of Ames	City of Ames	Apr-78	200	-174	1	1200	950	820,000	65	--	Babcock & Wilcox	Babcock & Wilcox		ESP/BH	Engdahl/77; Jensen/82; Fiscus/83; Barrett/89; Chapman/91
Ames RR Proj.	Unit#7	Ames	IA	City of Ames	City of Ames	City of Ames	Sep-75	200	174	1	900	850	380,000	35	--	Combustion Engg.	Combustion Engg.	UOP	ESP/BH	
Anoka Co./Elk River RR Project	Elk River#1-3	Anoka Co.	MN	NSP/Utd. Power Assoc.	NSP	Utd. Power Assoc./NSP	Aug-89	1,500	1,500	3	815	700	333,600	33	--	Babcock & Wilcox	Sprg/Riley	GE/Res-Cottrell	DS/BH	Scheatzle/89; Collins/92; Steinbeck/92
Mankato RRF	Wilmarth#1,2	Mankato	MN	N. States Power	N. States Power	N. States Power	Aug-87			2	825	700	109,000	11	--					Barrett/89; Follett/89
Ramsey/Washington RRF	Red Wing	Newport	MN	NSP/Red Wing	N. States Power	N. States Power	Jul-87	1,200	1,150	2	650	725	24,000	24	22	FW/B&W	Detroit Stoker	Beico	ESP	Barrett/89; Follett/89
<b>(b) Not Now Firing RDF/Shut Down</b>																				
Untd. Illum. Co.	Bridgeport Hbr#1	Bridgeport	CT				Nov-79			1				80		B&W cyclone				McGowin/82; Fiscus/83
Comm. Ed. Co.	Crawford#7,8	Chicago	IL				Oct-79 to Dec-79			2				200/325		Combustion Engg.				McGowin/82; Fiscus/83; Turner/84
Baltimore Gas & Elect. Co.	Crane#2	Baltimore	MD	Baltimore G & E			Feb-84	1,200	600	2	2475	1050	1,362,000	200	168	B&W cyclone		General Electric	BH	Bourquin/83; Fiscus/83
Union Elect. Co.	Meramec#1,2	St. Louis	MO				Apr-72 to Nov-75			1				125		Combustion Engg.				Engdahl/77; McGowin/82; Fiscus/83;
Atlantic Electric Co.	B. L. England#1	Beesleys Point	NJ	Atlantic Electric							1850	1005		129		Babcock & Wilcox				Nicoletti/89
Rochester Gas & Elec.	Russet#1-4	Rochester	NY				Sep-81 to 1984			4				42/75		Combustion Engg.				Corson/82; McGowin/82; Krause/89
Madison Gas & Elec.	Blount St.#7, 8	Madison	WI	Madison Gas & Electric			Jan-79	400	250	2	1250	950	850,000	55		Babcock & Wilcox	Combustion Engg.	ABB-CE	CYC/ESP	Barlow/82; McGowin/82; Fiscus/83; Barrett/89; Jacobus/89
Wisconsin Elect. Power Co.	Oak Creek#7, 8	Milwaukee	WI				Mar-77 to Aug-80			2				310		Combustion Engg.				Petersdorf/80; Plumley/80; 81; McGowin/82; Krause/83
<b>KEY</b>																				
ERF: Energy Recovery Facility																		BH: fabric filter		
RF: Recovery Facility																		CYC: cyclone		
RR: Resource Recovery																		DS: dry scrubber		
RRF: Resource Recovery Facility																		ESP: electrostatic precipitator		
WTE: Waste-to-Energy Facility																		LI: lime injection		
																		NOX: NOx control		
																		WS: wet scrubber		



Table C-1. Summary of Waste-to-Energy Units Planned in the U.S.

Project	Location	State	Start	Owner	Operator	Steam Condt's			Capacity	Plant	No.	Output, MW		Emissions	Component Manufacturers						
						psi	°F	lb/h				t/d	Product		Units	Gross	Net	Control	Boiler	Grate	Emissions
<b>Mass-Burn—Grate-Type Firing</b>																					
Lisbon	Lisbon	CT	Mar-95	TBD	Wheelabrator	900	830	135,400	500	Elec.	2	15	13	DS/NOx/BH	B & W/Riley	Von Roll	TBD				
Lee Co. Solid WTE	Fort Myers	FL	Jan-95	Lee Co.	Ogden Martin	850	825	337,500	1,200	Elec.	2	39	33.5	DS/NOx/BH	Distral	Martin	ABB				
East Bridgewater RRF	East Bridgewater	MA	Jan-95	American RefFuel, Inc.	American RefFuel, Inc.	855	842	400,000	1,500	Elec.	2	50	40	DS/NOx/BH	TBD	Deutsche Babcock	TBD				
Montachusett Regional RF	Shirley	MA	Dec-95	TIRU	TRU	900	712	70,000	243	Elec.	2	7	5.8	DS/NOx/BH/Hg	TBD	TIRU, S.A.	TBD				
Montgomery Co. RRF	Dickerson	MD	Dec-95	N. E. Maryland W. Disp. Auth.	Ogden Martin	865	830	512,000	1,800	Elec.	3	83.6	69	DS/NOx/BH/Hg	TBD	Martin	TBD				
Arrowood RRF	Mecklenburg Co.	NC	Jan-96	Mecklenburg Co.	Wheelabrator	675	750	150,000	600	Elec.	2	16	12.5	DS/NOx/BH	Babcock & Wilcox	Von Roll	Wheelabrator				
Mercer Co. RRF	Hamilton Twncshp	NJ	Jan-96	Mercer Co. Improv. Auth.	Ogden Martin Sys.	865	825	480,000	1,450	Elec.	2	52	47	DS/NOx/BH/Hg	TBD	Martin	TBD				
Hudson Co.	Kearny	NJ	Jan-96	Ogden Martin Sys.	Ogden Martin Sys.	865	830	410,000	1,500	Elec.	2	45	38.3	DS/NOx/BH/Hg	TBD	Martin	TBD				
Union Co.	Rahway	NJ	Feb-94	Union Co. Util. Auth.	Ogden Martin	865	830	360,000	1,440	Elec.	3	44	39	DS/NOx/BH/Hg	Distral	Martin	Res-Cottrell				
Brooklyn Navy Yard RRF	Brooklyn	NY	Jan-99	Wheelabrator Env.	Wheelabrator Env.	465	475	650,000	3,000	Steam	4	0	0	DS/NOx/BH/Hg	Babcock & Wilcox	Von Roll	Wheelabrator				
Green Island	Green Island	NY	Jun-96	American RefFuel	American RefFuel, Inc.	855	842	400,000	1,500	Elec.	2	50	40	DS/NOx/BH	TBD	Deutsche Babcock	TBD				
Onondaga Co.	Onondaga	NY	Sep-95	Ogden Martin Sys.	Ogden Martin Sys.	865	830	311,646	990	Elec.	3	39	30	DS/NOx/BH/Hg	TBD	Martin	Env. Elements				
Glendon RR Proj.	Glendon	PA	Jan-96	Energetics-Glendon Inc.	Delmarva Operat. Serv.	750	750	130,000	500	Elec.	2	14	12.5	DS/NOx/BH/Hg	Riley/Tak	Riley/Tak	TBD				
West Pottsgrove R/RRF	Stowe	PA	Oct-95	Wheelabrator Pottsgrove	Wheelabrator Pottsgrove	900	850	336,000	1,500	Elec.	2	45	40	DS/NOx/BH/Hg	Babcock & Wilcox	Von Roll	Wheelabrator				
Wheelabrator-Falls ERF	Morrisville	PA	May-94	Wheelabrator-Falls	Wheelabrator-Falls	900	850	380,000	1,600	Elec.	2	50	45	DS/NOx/BH/Hg	Babcock & Wilcox	Von Roll	Wheelabrator				
Quonset Point RRF	N. Kingston	RI	Jan-96	RI Solid Waste Mngt. Corp.	Ogden Martin	650	630	182,000	710	Elec/St	2	21	18	DS/BH	Distral	W&E	TBD				
Johnston RRF (Central Ldfill)	Johnston	RI	Jan-96	RI Solid Waste Mngt. Corp.	Ogden Martin	850	825	150,000	750	Elec.	2	21	17	DS/NOx/BH	TBD	Martin	TBD				
<b>Mass-Burn—Modular Combustor</b>																					
Sangamon Co.	Illioipolis	IL	Jan-96	Kirkby-Coffman Inc.	Kirkby-Coffman Inc.	600	575	90,000	450	Elec.	3	8	6	DS/NOx/BH	TBD	L. Bouillet	L. Bouillet				
<b>Mass-Burn—Rotary Combustors</b>																					
Monroe Co.	Bloomington	IN	Jan-96	Westinghouse	Westinghouse	425	625	160,000	300	Elec/St	2	10.5	8.9	DS/BH	TBD	W'house/O'Conner	TBD				
Montgomery Co. South	Dayton	OH	Jan-96	Montgomery Co.	Montgomery Co.	500	650	240,000	900	Elec.	3	18.6	17.7	ESP/DS	Comb. Engg.	Montenay Co.	Utd. McGill				
<b>RDF-Fired Units with Suspension or Grate Burning</b>																					
W. Suburban R&EC	Summit	IL	Jan-96	W. Sub. R/EC Inc.	Kirby-Coffman Inc.	850	825	393,000	1,400	Elec.	1	45	36	DS/NOx/BH	TBD	TBD	Flakt				
Petersburg (Utd. Bio-Fuel)	Petersburg	VA	Jan-96	United Bio Fuel Indust.	United Bio Fuel Indust.	750	700	250,000	700	Elec.	1	12	9	ESP/BH	Abco	Consumat	TBD				

# REPORT DOCUMENTATION PAGE

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