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

Summary

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 (HCI) present in the gas phase. The apparent role of HCI 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 modem 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.