# Priorities for Corrosion Research and Development for the Electric Power Industry



*Technical Report*

# Priorities for Corrosion Research and Development for the Electric Power Industry

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# REPORT SUMMARY

This report identifies the specific corrosion problems that result in the largest costs to the electric power industry. It describes the corrosion-related research and development (R&D) that is underway to address these problems and also discusses additional R&D that appears warranted. The report discusses several high cost areas where new research is judged to be unnecessary since the problems are well understood, but where improved application of already available technology seems important.

## Background

EPRI report 1004662, Cost of Corrosion in the Electric Power Industry, published in October 2001, described the results of a study that analyzed costs caused by corrosion in the electric power industry. This study determined the fraction of the total costs of broad activities that are due to corrosion, but did not develop a sufficiently detailed breakdown of the specific causes of the costs within each activity to allow individual specific corrosion problems to be ranked in terms of their cost impact. This lack of detail was mainly the result of the nature of the available cost data from utilities and from government reports, which are not structured to quantify costs by specific corrosion problem. A breakdown of cost by specific corrosion problem would be useful: it would highlight the high-cost problems, could justify an investment in corrosion protection methodologies, and provide guidance on future R&D needs.

## Objectives

To identify the specific corrosion problems in the electric power industry that result in the highest costs; to identify the additional R&D that should be performed for each of these problems; to identify the areas where improved corrosion management or technology transfer should be applied to reduce costs using already available technology.

## Approach

The project team re-evaluated the cost data in EPRI report 1004662, reviewed relevant literature including EPRI program documents, and consulted EPRI technical staff and utility representatives familiar with each technical area in order to develop a ranking of specific corrosion problems in order of cost to the electric power industry.

## Results

Lists of the highest cost corrosion problems were developed for the fossil generation, nuclear generation, combustion turbine generation, and transmission and distribution sectors. In a combined list for all sectors, the fifteen highest cost items, listed in descending order of cost, are as follows:

- Corrosion product activation and deposition [nuclear sector]
- PWR steam generator tube corrosion [nuclear sector]
- Boiler tube waterside/steamside corrosion [fossil sector]
- Heat exchanger corrosion [fossil and nuclear sectors]
- Stress corrosion cracking and corrosion fatigue in turbines [fossil and nuclear sectors]
- Fuel cladding corrosion [nuclear sector]
- Corrosion in electric generators [fossil and nuclear sectors]
- Flow-accelerated corrosion (FAC) [fossil and nuclear sectors]
- Corrosion of raw water piping [fossil and nuclear sectors]
- IGSCC of BWR piping and internals [nuclear sector]
- Oxide particle erosion of turbines [fossil sector]
- Boiler tube fireside corrosion [fossil sector]
- PWSCC of non-SG alloy 600 parts [nuclear sector]
- Corrosion of concentric neutrals [distribution sector]
- Copper deposition in turbines [fossil sector]

For each problem, the team identified current R&D and planned R&D and developed recommendations for additional R&D, corrosion management, and technology transfer that would likely have the greatest impact on reducing the cost of corrosion in the industry.

## EPRI Perspective

The cost estimates on which the rankings of corrosion problems are based are approximate since hard cost data for specific problems were not available and the rankings reflect judgments made by the author based on input from the experts consulted during the course of the project. Nevertheless, these results can help in evaluating the needs for R&D, improved corrosion management, and better technology transfer.


## Keywords

Corrosion
Costs
Electric power generation
Research and development
Technology transfer
Transmission and distribution

# ABSTRACT

This report provides a cost ranking of corrosion related problems affecting the electric power industry. The methodology used to develop the cost ranking was to start with the estimates for cost of corrosion in the various sectors of the electric power industry developed in EPRI report 1004662, Cost of Corrosion in the Electric Power Industry, October 2001, and then to rank and distribute these costs to specific corrosion problems based on assessments by experts in each of the areas of technology involved. The assistance of these same experts was used to identify the R&D currently underway, and the new R&D that is planned or should be initiated. Finally, these same experts identified areas where solutions to corrosion problems are already available, but improved technology transfer or management attention is required to have the technology more effectively implemented.

The report ranks the cost of corrosion problems in the fossil generation, combustion turbine generation, nuclear generation, and transmission and distribution sectors of the electric power industry. It indicates that corrosion costs of certain specific problems in the nuclear power generation and fossil steam power generation sectors are the highest in the industry. The three problems identified as resulting in the highest costs are (1) corrosion product activation and deposition in nuclear plants (affecting both BWRs and PWRs), (2) steam generator tube corrosion in PWRs, and (3) waterside/steamside corrosion of boiler tubes in fossil plants. These and the other most costly problems in the nuclear and fossil sectors of the industry are considered to warrant extensive attention. The corrosion costs of some distribution, transmission and combustion turbine sector problems are also large, and also warrant attention.

# ACKNOWLEDGMENTS

The author wants to acknowledge the extensive amount of help that was provided by the EPRI and utility experts listed below who provided expert guidance with regard to identifying, describing and ranking the most important corrosion problems affecting the electric power industry. These same experts also identified and described current R&D, needed additional R&D, and areas where increased utility management attention and/or technology transfer are needed. Many of these same experts, including the EPRI project manager, Barry Syrett, also helped by reviewing and correcting drafts of this report. The input of these experts was essential to preparation of this report.

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# LIST OF ABBREVIATIONS AND ACRONYMS

| | |
|---|---|
| **AOA** | Axial Offset Anomaly |
| **AVT** | All-Volatile Treatment |
| **BTF** | Boiler Tube Failure |
| **BWR** | Boiling Water Reactor |
| **BWRVIP** | BWR Vessels and Internals Program |
| **CCURB** | Corrosion Control Using Regenerative Biofilms |
| **CEA** | Commissariat à l'Energie Atomique |
| **CRDM** | Control Rod Drive Mechanism |
| **CT** | Combustion Turbine |
| **CWS** | Circulating Water System |
| **DOE** | Department of Energy |
| **EBA** | Enriched Boric Acid |
| **ECP** | Electrochemical Corrosion Potential |
| **FAC** | Flow-Accelerated Corrosion |
| **FGD** | Flue Gas Desulfurization |
| **GE** | General Electric |
| **HRSG** | Heat recovery steam generator |
| **HTF** | HRSG Tube Failure |
| **HWC** | Hydrogen Water Chemistry |
| **ID** | Inner Diameter |
| **IASCC** | Irradiation Accelerated Stress Corrosion Cracking |
| **IGA/SCC** | Intergranular Attack/Stress Corrosion Cracking |
| **IGSCC** | Intergranular Stress Corrosion Cracking |
| **IHSI** | Induction Heating Stress Improvement |
| **LTCP** | Low Temperature Crack Propagation |
| **LTOC** | Long-Term Creep Rupture |
| **MIC** | Microbiologically-Influenced Corrosion |
| **NDE** | Nondestructive Examination |

| | |
|---|---|
| **NMCA** | Noble Metal Chemical Addition |
| **NOx** | Nitrogen Oxides |
| **OD** | Outer Diameter |
| **O&M** | Operation and Maintenance |
| **PCI** | Pellet-Clad Interaction |
| **PWR** | Pressurized Water Reactor |
| **PWSCC** | Primary Water Stress Corrosion Cracking |
| **RH** | Reheater |
| **RUB** | Reverse U-Bend |
| **SCC** | Stress Corrosion Cracking |
| **SGMP** | Steam Generator Management Program |
| **SH** | Superheater |
| **SS** | Stainless Steel |
| **SWAP** | Service Water Assistance Program |
| **SWS** | Service Water System |
| **T&D** | Transmission and Distribution |
| **TBC** | Thermal Barrier Coating |
| **TT** | Thermally Treated |

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# 1
# INTRODUCTION

The main objective of this project was to develop a ranking of corrosion related problems affecting the electric power industry. This ranking was based on two main factors: (1) the cost impact of the corrosion problem to the electric power industry, and (2) informed judgment as to the need for and likelihood of success of research and development (R&D) at reducing the costs of the corrosion problem. An additional objective of the project was to identify and highlight cost effective actions that could be taken now, based on currently available technology, to ameliorate corrosion costs.

Report 1004662 described the results of a previous EPRI study that analyzed costs caused by corrosion in the electric power industry.[1] This study served to determine the fraction of the total costs of broad activities that are due to corrosion, but did not develop a sufficiently detailed breakdown of the specific causes of the costs within each activity to allow individual specific corrosion problems to be ranked in terms of their cost impact. This lack of detail was mainly the result of the nature of the available cost data from utilities and from government reports, which were not structured to quantify costs by corrosion problem. For example, the previous study identified that 30% of the reported "Maintenance of Boiler Plant" costs reported to the government were due to corrosion, but did not identify the fractions of these costs that were due to specific corrosion problems such as waterside corrosion of water wall tubes, fireside corrosion of waterwall tubes, stress corrosion cracking (SCC) in turbines, etc. Since the available quantitative cost data do not provide the desired breakdown and segregation of costs for specific corrosion problems, it was decided that the desired detail should be estimated using the assistance of experts familiar with each area of the technology.

For the reasons discussed above, in the present study the data in report 1004662[1] were re-evaluated, relevant literature was reviewed, and EPRI technical staff and utility representatives were consulted to develop a ranking of specific corrosion problems in order of cost to the electric power industry. Based on this evaluation, estimates of the costs of various specific corrosion problems were developed. Recommendations were then developed for R&D that, if completed successfully, would be expected to have maximum impact on reducing the cost of corrosion in the industry.

The methodology used in the following sections for estimating costs associated with major corrosion problems affecting the fossil steam generation, combustion turbine (CT) generation, and transmission and distribution (T&D) sectors was as follows (the methodology for the nuclear power sector was somewhat different, as discussed later).

- The total annual corrosion costs due to operations and maintenance O&M, depreciation, and fuel (if applicable) were taken from report 1004662.[1]

- A ranking of the cost impact from 10 (highest) to 0 (none) was assigned to each identified significant corrosion problem. These ranks were based on discussions with EPRI and utility experts, and review of technical literature such as EPRI workshop proceedings. This ranking was done separately for each of the O&M, depreciation and fuel (if applicable) categories.
- A "miscellaneous" or "general" corrosion problem entry was used for each sector to represent the corrosion costs not attributable to one of the identified major corrosion problems.
- The sum of the assigned ranks to all of the corrosion problems in each of the O&M, depreciation, and fuel (if applicable) categories was then determined.
- The estimated annual corrosion cost for each corrosion problem was then calculated by multiplying the total corrosion cost in the category [O&M, depreciation, or fuel (if applicable)] by the rank for that problem and dividing by the sum of the ranks for all of the problems in that category.
- The estimated total annual O&M, depreciation, and fuel (if applicable) corrosion cost for each problem was then determined by summing the costs for these categories.

Distribution of costs to specific nuclear power corrosion problems was handled somewhat differently than for the sectors covered above. The main difference was that the costs for nuclear plants were distributed to specific corrosion problems starting from detailed costs for specific work activities. This was the result of having obtained more detailed cost breakdown data for nuclear plants than for the other sectors. The details of this process are described in Section 4.

# 2
# FOSSIL STEAM GENERATION SECTOR

This section summarizes information regarding the problems that cause most of the costs of corrosion in the fossil steam generation sector of the electric power industry. Most of this section concentrates on coal-fired boiler plants, but one problem affecting mostly oil-fired plants is covered. For each corrosion problem, the known causes are summarized together with any ongoing R&D, and needs for additional R&D. The starting point for estimating the costs of the various corrosion problems was the compilation of total corrosion costs for this sector in report 1004662.[1] These costs are shown in Table 2-1 (the numbers were rounded in order to avoid giving an impression of false precision).

**Table 2-1**
**Summary of 1998 Corrosion Costs to Consumers for Fossil Fired Steam Power (Listed as Fossil Steam Power in Report 1004662)[1]**

| 1998 O&M Non-Fuel Corrosion Cost* | 1998 Fuel O&M Corrosion Cost | 1998 Depreciation Corrosion Cost | 1998 Total Corrosion Cost |
|---|---|---|---|
| $3,435,000,000 | $1,934,000,000 | $1,142,000,000 | $6,511,000,000 |

* This category includes the corrosion cost caused by lost production, which is considered not to contribute to fuel depreciation, but rather to add to the corrosion costs associated with equipment operation and maintenance.

As discussed in Table 4-2 of report 1004662,[1] the "1998 Fuel O&M Corrosion Cost" of $1,934 million listed above in Table 2-1 is based on the cost of coal being increased by 2% to meet purity limits established to minimize corrosion in the power plant. This cost was considered reasonable since reviews of fossil plant corrosion problems in the ASM Metals Handbook and in EPRI's Boiler Tube Failures Book indicate that use of cleaner coal is a way to minimize fireside corrosion problems.[2,3,4] However, recent discussions with coal procurement experts from four utilities and with experts at EPRI during the current project indicate that meeting corrosion-based impurity limits has not in practice resulted in increased costs for coal. Meeting coal impurity limits imposed to achieve environmental constraints (e.g., for sulfur), BTU requirements, and ash loading has been found to result in the coal being acceptable from a power plant corrosion standpoint. In addition, utilities find that it is more cost effective to modify the plant to withstand the corrosion problem than to impose corrosion-based impurity limits on coal. These plant modification costs are covered in the O&M Non-Fuel Corrosion Cost and the Depreciation Corrosion Cost. For the above reasons, the Fuel O&M Corrosion Cost was not included in the costs addressed in the balance of this section.

The following parts of this section discuss the corrosion problems that lead to the most significant non-fuel O&M costs and depreciation costs involved in the fossil steam generation sector of the industry. These corrosion problems are discussed approximately in the order indicated by the total annual estimated corrosion cost to the nation in 1998, with the costliest problems discussed first. The estimated corrosion costs are shown in Table 2-2 and were developed using the methodology described in Section 1. The discussion of each corrosion problem includes a brief review of current R&D on that problem, and needs for future R&D. In order to illustrate how the cost estimates were developed, the detailed development of costs for waterside and fireside corrosion shown in Table 2-2 is described below.

- The total annual corrosion costs due to non-fuel-related O&M and to depreciation were taken from report 1004662,[1] as shown in Table 2-1 and at the top of Table 2-2.
- A ranking of the cost impact from 10 (highest) to 0 (none) was assigned to each identified significant corrosion problem listed in Table 2-2. These ranks were estimated by the author based on discussions with EPRI and utility experts, review of technical literature such as EPRI workshop proceedings and industry data on causes of forced outages. This ranking was done separately for each of the O&M and depreciation categories. The "10" entry for waterside corrosion in the O&M column reflects the high impact of waterside corrosion on O&M costs, while the "2" entry reflects the lower effect of fireside corrosion problems on O&M costs.
- The "all other" corrosion problem entry in Table 2-2 represents the corrosion costs not attributable to one of the identified major corrosion problems.
- The sum of the assigned ranks to all of the corrosion problems in each of the O&M and depreciation categories was then determined, as indicated in Table 2-2.
- The estimated annual corrosion cost for each corrosion problem was then calculated by multiplying the total corrosion cost in the category [O&M or depreciation] by the rank for that problem and dividing by the sum of the ranks for all of the problems in that category, e.g., by 10/37.5 for O&M waterside/steamside corrosion costs for boiler tubes, and 2/37.5 for O&M fireside corrosion costs for waterwall tubes.

**Table 2-2**
**1998 Costs of Corrosion Problems Affecting Fossil Steam Plants**

| Corrosion Problem | O&M Non-Fuel-Related Corrosion Cost | | Depreciation Corrosion Cost | | Total Corrosion Cost |
|---|---|---|---|---|---|
| | Ranking | Dollars | Ranking | Dollars | |
| All Corrosion Problems in Fossil Steam Plants | | $3,435,000,000 | | $1,142,000,000 | $4,577,000,000 |
| Waterside/Steamside Corrosion of Boiler Tubes | 10 | $916,000,000 | 8 | $228,400,000 | $1,144,400,000 |
| Turbine CF & SCC | 5 | $458,000,000 | 5 | $142,750,000 | $600,750,000 |
| Oxide Particle Erosion of Turbines | 3 | $274,800,000 | 3 | $85,650,000 | $360,450,000 |
| Heat Exchanger Corrosion | 3 | $274,800,000 | 3 | $85,650,000 | $360,450,000 |
| Fireside Corrosion of Waterwall Tubes | 2 | $183,200,000 | 5 | $142,750,000 | $325,950,000 |
| Generator Clip to Strand Corrosion | 2 | $183,200,000 | 1 | $28,550,000 | $211,750,000 |
| Copper Deposition in Turbines | 1 | $91,600,000 | 2 | $57,100,000 | $148,700,000 |
| Fireside Corrosion of SH & RH tubes | 1 | $91,600,000 | 2 | $57,100,000 | $148,700,000 |
| Corrosion of FGD System | 0.5 | $45,800,000 | 3 | $85,650,000 | $131,450,000 |
| Liquid Slag Corrosion of Cyclone Boilers | 1 | $91,600,000 | 1 | $28,550,000 | $120,150,000 |
| Backend Dew Point Corrosion | 1 | $91,600,000 | 1 | $28,550,000 | $120,150,000 |
| Generator Cooling Water Clogging & Plugging | 1 | $91,600,000 | 1 | $28,550,000 | $120,150,000 |
| FAC of steam plant piping | 1 | $91,600,000 | 1 | $28,550,000 | $120,150,000 |
| Corrosion of Service Water, Circ. Water, and Other Water Systems | 1 | $91,600,000 | 1 | $28,550,000 | $120,150,000 |
| All Other (corrosion of structures, ash handling equipment, coal handling equipment, oil pipes and tanks, electrical equipment, etc.) | 5 | $458,000,000 | 3 | $85,650,000 | $543,650,000 |
| Sum of Ranking Points / Check Totals | 37.5 | $3,435,000,000 | 40 | $1,142,000,000 | $4,577,000,000 |

## 2.1 Overview of Boiler Tube Failure (BTF) Causes

The most important corrosion problem affecting coal-fired boiler power plants is boiler tube failure (BTF). BTF can occur due to waterside corrosion, fireside corrosion, or other non-corrosion related causes such as erosion due to fly ash. The overall situation with regard to BTF is covered in this section, and then the waterside/steamside and fireside are treated separately in Sections 2.2 and 2.6, respectively.

EPRI reports that availability losses due to BTF have been increasing since 1991. Without exception, power producers report to EPRI that BTF is the biggest reliability problem they currently face. Of the boiler tube failures occurring in coal-fired steam plants, about 50% are reported to be chemistry (corrosion) related. The worsening of BTF problems over the last 10 years is attributed by EPRI to the results of deregulation-induced changes such as loss of key people, and the resulting failure to implement lessons from the past.

The current ranking of BTF mechanisms at coal-fired steam power plants by EPRI (including those not caused by corrosion) is shown below in decreasing order of importance:

(1) Corrosion fatigue (CF) on the waterside. This is a complex problem and can occur at many locations, each with unique detection and remediation problems. It is strongly influenced by the boiler water chemistry.

(2) Long term overheat creep (LTOC) of superheater (SH) and reheater (RH) tubes. This is mainly a thermo-mechanical creep problem, but is aggravated by corrosion in two ways. First, the growth of internal steam-side oxides leads to increases in tube wall temperature and acceleration of creep. Second, thinning of tubes due to fireside corrosion can increase stresses and thereby increase creep rates.

(3) Fly ash erosion. This is a mechanical erosion problem, and is not due to corrosion.

(4) Underdeposit corrosion of waterwalls. This problem, which includes three mechanisms (hydrogen attack, acid phosphate corrosion, and caustic gouging) is essentially completely controlled by feedwater and boiler water chemistry.

(5) Soot blower erosion. This is a mechanical erosion problem and is not due to corrosion.

Fireside corrosion due to nitrogen oxide (NOx) control programs is far down the list of BTF mechanisms. One reason for this is that most susceptible units have applied weld overlays to the areas at high risk. Thus, the fireside corrosion problem has resulted in significant repair or capital expenses in the past, but is not a cause for high repair expenditures at the current time, except at those plants that have recently installed low-NOx systems.

Pitting is an increasing problem at coal-fired stations. This is attributed to improper shutdown.

## 2.2 Waterside/Steamside Corrosion of Boiler Tubes (economizer, waterwall, superheater and reheater)

### *2.2.1 Description of Problems*

As noted in Section 2.1, the main waterside/steamside corrosion problems affecting boiler tubes are corrosion fatigue (CF), underdeposit corrosion of waterwalls, and pitting. The main characteristics of these problems include:

- <u>Corrosion Fatigue (CF)</u> - CF is the most frequent waterside corrosion cause of BTF. It mainly affects waterwall tubes, although it also occasionally affects economizer tubes. CF is nearly always associated with tube attachments or other locations where significant constraint stresses develop. It initiates at the inside surface, sometimes in connection with pitting, with the cracks oriented normally to the main applied stress. It is attributed to the synergistic effects of cyclic stresses and environment. The severity of CF has been found to be affected by factors such as the type of operation (peaking, cycling, etc.), the type and frequency of chemical cleaning, the type of water chemistry used, how well the chemistry is controlled, and pH swings during shutdowns. Remedial actions for CF have been developed and found to be effective, such as improvements in water chemistry, improvements in shutdown/layup procedures, and design changes of tube attachments to eliminate or reduce constraint.

- Underdeposit Corrosion – Underdeposit corrosion occurs due to three different mechanisms: hydrogen damage, acid phosphate corrosion, and caustic gouging. The three mechanisms affect similar locations in the boiler, and all three occur under deposits and result in gouges. However, the causes of the corrosion are different, have different microstructural and deposit features, and require different remedies. Summary descriptions of these mechanisms are as follows:
  - Hydrogen Damage – This form of corrosion occurs under deposits where acid forming species such as chlorides concentrate due to boiling. The acid species cause corrosion of the steel tube, releasing hydrogen. The corrosion is characterized by non-protective magnetite, such that the corrosion proceeds approximately linearly with time. The hydrogen released by the corrosion reacts with carbides in the steel, resulting in decarburization and weakening, and the concurrent production of methane gas at grain boundaries that leads to fissures. The essential features leading to the problem are the development of deposits and the presence of acid forming species in the water that can concentrate in and under the deposits due to boiling. Corrective measures include water chemistry improvements to minimize deposit formation, boiler design or operational changes to minimize deposit formation, chemical cleaning to remove deposits, and water chemistry improvements to minimize ingress of acid forming species.
  - Acid Phosphate Corrosion – Acid phosphate corrosion occurs under deposits where mono- or di-sodium phosphate concentrates due to boiling. The acid phosphate species cause thinning or gouging by a material dissolution mechanism. The corrosion is characterized by development of severe gouging and the formation of phosphate containing deposits. This type of corrosion is only associated with operation on phosphate water chemistry using mono- or di-sodium phosphate. Corrective measures include water chemistry improvements to minimize deposit formation, boiler design or operational changes to minimize deposit formation, chemical cleaning to remove deposits, and water chemistry improvements to minimize formation of acid phosphate species.
  - Caustic Gouging – This mode of corrosion occurs where caustic concentrates to high levels due to boiling within deposits. The concentrated caustic dissolves the normally protective magnetite layer, leading to rapid corrosion of the underlying tube material. The corrosion is characterized by development of severe gouging and the formation of sodium containing deposits. This type of corrosion can occur with several water chemistries, including caustic water chemistry, AVT, and some phosphate water treatments. Corrective measures include water chemistry improvements to minimize deposit formation, boiler design or operational changes to minimize deposit formation, chemical cleaning to remove deposits, and water chemistry improvements to minimize the presence of free caustic.

- Pitting – Pitting is a significant degradation mechanism affecting boiler tubes, but causes much fewer BTFs than the corrosion fatigue and underdeposit mechanisms discussed above. Pitting most often occurs in economizer tubes, but can occur in other areas including waterwall tubes and superheater/reheater tubes. It is generally the result of improper lay up. Pitting during improper layup occurs as the result of exposure to stagnant highly oxygenated water combined with the presence of acid forming anions such as chlorides in the water. Corrective measures for shutdown/layup caused pitting involve revising shutdown and layup procedures either to keep surfaces dry, or to ensure that wet layup conditions are protective (e.g., impurities such as oxygen, carbon dioxide and acid forming species are excluded, an alkaline pH is maintained, and oxygen scavengers such as hydrazine are present). In addition to pitting associated with poor shutdown and layup, pitting can be caused by poor chemical cleaning practices and, in reheaters, by carryover of $Na_2SO_4$ during operation, which combines with moisture from condensation during shutdown.

In addition to the above most significant waterside/steamside corrosion induced problems, there are a variety of other waterside/steamside corrosion induced problems, as described in the BTF Book,[5] including supercritical waterwall cracking, erosion/corrosion in economizer inlet headers, stress corrosion cracking, etc. Another BTF mechanism, long-term overheating creep (LTOC) of SH/RH tubes, in some cases is significantly accelerated by a steamside corrosion mechanism: buildup of internals oxides leads to increases in tube wall temperature and accelerated creep.

All of the problems discussed in this section, occuring as the result of corrosion initiating from the waterside/steamside of the tubes or headers in the boiler, are strongly influenced by the water chemistry types used in the plants, and are strongly affected by how carefully the water chemistry is controlled. Extensive industrial experience has demonstrated that an effective BTF reduction program, including careful control of water chemistry, significantly reduces forced outage rates due to BTF, e.g., from levels of about 3% to about 1%.

### 2.2.2 Current R&D

Extensive research has been performed in past years to evaluate all of the BTF waterside/steamside failure mechanisms, e.g., corrosion fatigue, underdeposit corrosion, etc., and EPRI considers that all of the important corrosion issues affecting boiler watersides/steamsides have been adequately studied. The lessons learned are reflected in documents such as the Flow-Accelerated Corrosion (FAC) Book (TR-106611), the Boiler Tube Failure Book (TR-105261), and eleven fossil plant water chemistry guidelines (TR-102285, TR-103665, TR-104007, TR-104422, TR-105040, TR-105041, TR-107754, TR-108859, TR-113692, 1003994, and 1000457). While this previous work has developed a strong technical basis for understanding and correcting waterside/steamside corrosion induced problems, actual application of these lessons by the industry is not as thorough and complete as desired, and corrosion problems continue to cause undesirable amounts of BTF. For this reason, work remains active on cycle chemistry targets for coal-fired steam power plants (Boiler and Turbine Steam and Cycle Chemistry Program). These activities are directed at helping power producers change their corporate cultures and apply the already developed technology in a more systematic and effective manner.

### 2.2.3 Future R&D

No important future research needs were identified in this area during discussions with EPRI experts and utility engineers. They consider that the problems causing the high corrosion costs are well understood and that additional R&D will not change this situation. They consider that the main efforts need to be directed at changing corporate cultures of power producers so that they more effectively apply the already developed and understood technologies. Towards this end, programs are planned to develop updated guidelines and software to help evaluate cycle chemistry and justify improvements, and to reduce deposition problems around the cycle. Programs are also planned to develop improved NDE methods for monitoring the occurrence of boiler tube corrosion problems.

## 2.3 Stress Corrosion Cracking (SCC) and Corrosion Fatigue (CF) of Turbine Disks and Blades

### 2.3.1 Description of Problems

SCC of turbine discs occurs at several locations, including at the central holes where discs are shrunk on to rotors (the SCC occurs typically at keyholes), at high stress locations along the disc face, and at blade attachments (often called rim cracking). Both SCC and CF affect turbine blades. SCC and CF of turbine discs and blades result in significant expenditures for periodic inspections and repairs, and for occasional replacements of rotors. There has been extensive work to determine the causes of the SCC and CF that affect turbine disks and blades, e.g., regarding how they vary as a function of turbine materials and steam system chemistry, and to develop inspection and remediation methods. The mechanical aspects of these problems are now well understood and under control. However, the corrosion and electrochemical aspects of the problem are not well understood and are the subject of current R&D.

### 2.3.2 Current R&D

EPRI has ongoing projects to better understand the causes of SCC in turbines and to identify the most cost effective remedies, especially for attachment areas and blade profiles. This includes a program directed at developing an improved understanding of the electrochemistry in the areas of the turbine where SCC and CF occur. It is expected that this will result in improved guidance as to how to optimize chemistry to minimize SCC and CF in turbines, and also regarding how to optimize turbine designs to minimize development of aggressive conditions.

Another area of research underway at the EPRI NDE Center involves development of repair methods for corrosion damage of turbine parts. This includes development of weld repair methods using variable composition welds, with the early layers being compatible with the turbine parts and the outer layers having an improved composition for SCC resistance.

### *2.3.3 Future R&D*

No needs for additional R&D were identified by EPRI experts or utility engineers, other than for continuing the current R&D described above.

## 2.4 Oxide Particle Erosion of Turbines

### *2.4.1 Description of Problems*

Spallation of oxides (also called exfoliation) from superheater tubes and headers, reheater tubes and headers, and main steam and reheat piping leads to oxide particle erosion of turbine blades. While erosion is not itself a corrosion problem, the oxide particles causing the erosion are formed as a result of corrosion and spallation in upstream components (growth of these oxides in superheater and reheater tubes is a factor in the long term overheat creep (LTOC) problem mentioned in Section 2.1). The oxide particle erosion problem has been well understood for 20 or more years for the conventional materials that have been used for superheaters and reheaters, and solutions have been developed, such as weld overlays of high pressure and intermediate pressure turbine inlet areas to increase their resistance to erosion, chemical cleaning of superheaters and reheaters to remove oxides before they spall, use of turbine bypass systems during startup to minimize erosion during this phase, replacement of tube, header and piping materials using materials with increased resistance to oxidation and spallation, and use of chromizing to treat the ID of tubes, headers and pipes to reduce the growth and spallation of oxides. Nevertheless, oxide particle erosion continues to occur and result in significant inspection, repair and remedial action costs. A factor in this problem is that oxidation and spallation of some of the newer materials used for superheaters and reheaters, such as T91, has lead to unexpected problems such as blockage of control valves, demonstrating that the oxidation and spallation behavior of these alloys are not well enough understood. Minimizing the problem in new or modified plants requires increases in capital investment, such as use of more costly superheater and reheater materials with increased resistance to oxide spallation.

### *2.4.2 Current R&D*

EPRI has recently published a report on oxide growth and spallation mechanisms that addresses the fundamental processes involved (TR-113501, Nov. 1999). EPRI has a current project directed at assessing the effectiveness of advanced coatings for reducing the rate of solid particle erosion of turbine parts. In addition, work is planned as noted below to reassess oxide growth and exfoliation, especially for newer materials such as T91.

### *2.4.3 Future R&D*

EPRI plans to further investigate the oxide growth and exfoliation problem, especially for new materials such as T91. The relatively high costs shown in Table 2-2 for this problem imply that more work to reduce the costs of this problem, in addition to the current work on advanced coatings and the planned new work on exfoliation, may be warranted for plants with older superheater/reheater materials, e.g., in the technology transfer area, to make sure that already available technology is effectively applied.

## 2.5 Heat Exchanger Corrosion

### 2.5.1 Description of Problems

There are a number of corrosion related problems that affect nuclear and fossil plant heat exchangers such as condensers, feedwater heaters, service water heat exchangers and lube oil coolers. For example, these problems include:

Inlet end erosion-corrosion of copper alloy tubes
Sulfide attack of copper alloy tubing in polluted waters
FAC or erosion-corrosion of carbon steel tubing and supports
Stress corrosion cracking of stainless steel tubing and some types of copper alloy tubing
Pitting and under-deposit corrosion of copper alloy, carbon steel, and stainless steel tubing
MIC attack of copper alloy, carbon steel and stainless steel tubing
Hydriding of titanium tubing
Galvanic corrosion of carbon steel water boxes and tube sheets and copper alloy tube sheets
Dealloying of copper alloy tube sheets and graphitization of cast iron waterboxes

These problems result in occasional leaks, sometimes cause forced outages or power reductions, and often require inspections, repairs and other remedial actions. In addition to these direct heat exchanger problems, corrosion of heat exchanger tubing can lead to problems elsewhere in the plant. In this regard, corrosion products picked up in the heat exchangers can lead to increased deposition of copper and iron in the boiler, causing problems such as underdeposit corrosion, and to copper deposition in high pressure turbines, leading to power losses.

### 2.5.2 Current R&D

EPRI's activities in this area are mainly directed at holding workshops to foster information exchanges among utilities and EPRI experts, especially with regard to inspection methods.

### 2.5.3 Future R&D

No specific needs for R&D on heat exchanger corrosion problems were identified, other than continuing emphasis on improving nondestructive examination (NDE) methods and on information exchange regarding how to cost effectively deal with corrosion problems.

## 2.6 Fireside Corrosion of Boiler Waterwall Tubes

### *2.6.1 Description of Problems*

Fireside corrosion of waterwall tubes involves the thinning of the tubes on the fireside due to corrosive attack by impurity species in the coal. Several mechanisms are considered possible, including sulfidation under reducing atmospheres, formation of pyrosulfates, and formation of alkali-iron trisulfates. The most common mechanism is considered to be the first of these three, i.e., sulfidation under reducing conditions. This mechanism has become more common as the result of reducing conditions that are required for NOx control. Deposition of iron sulfide seems to be a key step in the process. The corrosion is a function of the amount of sulfur and iron pyrites in the coal. In addition, under extremely reducing conditions, over 0.1% chlorine in the coal seems to lead to an increased rate of attack.

In previous years, the occurrence of fireside waterwall corrosion was most commonly associated with poor burner adjustment that led to locally reducing conditions, flame impingement, and similar operational problems. In addition, supercritical units that operated with AVT water chemistry sometimes experienced fireside waterwall corrosion as a result of tube wall temperature increases caused by heavy rippled magnetite deposits on the tube ID surfaces associated with use of AVT. This later problem was largely corrected in the 1990s by the conversion of the supercritical units to oxygen treatment (OT) water chemistry, which eliminated the ID deposit problem (and thus much of the fireside corrosion) at these plants. In recent years, the potential for fireside corrosion has increased in many plants as a result of changes made to meet NOx limits. With the advent of NOx restrictions, it has become important to maintain a reducing environment and to keep combustion temperatures lower. Burner designs were changed and staging used, in which the bottom of the boiler is maintained in a more reducing state and also at a lower temperature than in the past. The intent is to keep an outer layer of oxidizing air, but this is often ineffective. As a result, a side effect of going to NOx control has been the occurrence of widespread fireside corrosion associated with the presence of reducing conditions.

As mentioned above, most current fireside corrosion problems are attributed to attack by sulfidation under the reducing conditions required for NOx control. Because of the increasing emphasis in the industry on reducing NOx, reducing conditions are tending to become more severe. The more severe reducing conditions appear to make the effects of chlorine on fireside corrosion more important. Developing a better understanding of the effects of chlorine on fireside corrosion is an area of current research.

The first fix tried for fireside corrosion was to use sprayed-on coatings. These have not worked well. The current approach is to use weld overlays of materials such as Inconel 625 or Type 309 stainless steel (SS). Type 309SS works pretty well from a corrosion standpoint, but its high thermal expansion coefficient leads to high residual stresses. Weld overlays are now being applied at locations shown to be susceptible in combustion model predictions. It is the main method now being used to prevent waterwall fireside corrosion problems, and has resulted in a low rate of BTF due to fireside corrosion.

### 2.6.2 Current R&D

Current R&D is mainly directed at understanding and reducing fireside corrosion of waterwalls in boilers operating with staged combustion to minimize NOx emissions. This research is assessing how the levels of sulfur, iron pyrites (iron sulfide) and chlorine affect the wastage rates of waterwalls under the reducing conditions that occur in boilers being operated in a low NOx mode. Recent results demonstrate than even relatively low levels of chlorine in the coal interact with sulfur and lead to waterwall corrosion, and that this can affect the suitability of some mixes of coal, such as use of Powder River Basin coal (which has low sulfur and chlorine, but also low heating value) mixed with Illinois coal (which has higher sulfur and chlorine, but also higher heating value). In this regard, it appears that, if there are hot spots, KCl or NaCl can get over their melting points and cause rapid corrosion. Sulfur can also influence the process. The objective of the current research is to quantify how impurities interact to cause waterwall corrosion in low NOx boilers, and to thus aid in coal procurement and cleaning decisions, as well as providing guidance with respect to boiler operation and design.

New filler materials are being introduced for use as weld overlays to protect against fireside corrosion or wastage. EPRI has a project underway using a model boiler to assess the wastage rate of a range of waterwall weld overlay materials.

### 2.6.3 Future R&D

The situation regarding control of NOx is continuing to evolve, with the trend being towards ever tighter limits on NOx emissions. This is leading to changes in boiler design and operation. These have already led to some new or aggravated problems, and are likely to lead to further problems in the future. As a result, there is a need for continued research on how best to deal with these problems, including the following:

- Developing a highly reliable spray type coating (as an option to weld overlays) would be very useful. Weld overlays are effective, but they are expensive and slow to apply ($400/$ft^2$ vs. $100/$ft^2$ for spray type coatings). The spray type coating methods need to be automated, and care must be taken that the process does not adversely affect the corrosion resistance of the tube ID.
- Approaches to reduce fireside corrosion by better control of the combustion process are desirable, and are being addressed by EPRI projects. However, because of environmental concerns, the trend is towards ever lower NOx limits. These lower limits are expected to worsen corrosion problems. Thus, there remains a need to improve the resistance of the waterwall to fireside corrosion.
- Development of improved understanding and prediction of the chlorine mechanism of fireside corrosion is needed. (Chlorine attack occurs under reducing conditions; under the previous oxidizing conditions, the chlorine vaporizes). More generally, a better understanding is needed of the effects of impurities on corrosion under reducing conditions.
- Development of an inexpensive way to monitor the rate of fireside corrosion would be helpful. At present, removable coupons are used, but they are not very convenient and do not provide a rapid easy way to monitor many locations on a frequent basis.

## 2.7 Corrosion in Electric Generators

### 2.7.1 Description of Problems

Several decades ago, SCC of electric generator end rings was a major problem. This problem has largely been brought under control by replacement of the more susceptible end ring materials of 18% manganese - 5% chromium steel with 18% manganese - 18% chromium steel, and by periodic inspection and repair programs. Nevertheless, the need for continuing inspections and occasional repairs result in some continuing significant costs. Recently, cracks have been observed in at least four cases in end rings made of the new 18% manganese - 18% chromium steel. This may result in the need for increased inspection and maintenance, and the need for research to identify the causes and remedies.

There are currently two significant corrosion problems in large, water-cooled electric generators. One is clip-to-strand crevice corrosion of older GE generators that were fabricated using a copper -5% phosphorus braze alloy. EPRI research has shown that reducing oxygen to low levels can control the crevice corrosion. However, GE has indicated that it does not agree, and there has not been much utility acceptance of the EPRI proposed solution. Rather, utilities seem to be accepting the GE proposed repair/replacement approach, which, while expensive (about $5 million per generator), is believed to result in a permanent long term repair. The second problem affecting water-cooled electric generators is flow restrictions (plugging of the hollow strands or clogging of the strainers) in the stator cooling water system. Research indicates that the cause of the plugging/clogging problem is the occurrence in the system of intermediate oxygen levels between the recommended either fully aerated or fully deaerated (<50 ppb dissolved oxygen) conditions, and that improved control of oxygen levels will help prevent the problem in both the normally aerated and normally deaerated systems. Results suggest that a move from recommended dissolved oxygen levels can be tracked relatively easily by monitoring the electrochemical corrosion potential (ECP) but this method is not currently in use.

### 2.7.2 Current R&D

As noted above, recent research has been directed at developing a better understanding of, and solutions for, the clip-to-strand crevice corrosion and clogging/plugging problems that are affecting water-cooled generators. Work is continuing with regard to developing improved tools for judging the extent of clip-to-strand crevice corrosion, estimating when leaks are likely to occur, and assessing when rewind should be accomplished.

### 2.7.3 Future R&D

R&D directed at developing an understanding of the causes of the cracks seen in new 18-18 end rings seems warranted. In addition, in order to help utilities better control the water chemistry conditions in their electric generators, it would be desirable to develop a practical method to monitor the ECP in the generator stator cooling water system.

## 2.8 Copper Deposition in Turbines

### 2.8.1 Description of Problems

In plants with copper alloy tubes in their condensers and/or feedwater heaters, copper is picked up by the water as it circulates around the system. In some plants, a portion of this copper is removed by condensate polishers. However, in many plants, especially those with no condensate polishers or with copper alloy feedwater heaters downstream of the polishers, significant amounts of copper are carried to the boiler. Much of the copper is deposited on tube ID surfaces in the boiler. However, some of the copper is entrained in the steam by mechanical and vaporous carryover and by injection of feedwater into the steam in the attemperators. In units with steam pressures over about 2300 psi (15.9 MPa), the copper has sufficient solubility in the steam to be carried to the turbines in significant amounts and, in such units, tends to deposit on blades in the high pressure turbine. The buildup of copper on the turbine blades can lead to significant losses of efficiency and power.

### 2.8.2 Current R&D

EPRI has recently completed a project called Program Copper and issued guidelines for control of copper in fossil plants. EPRI provides consulting to utilities on a request basis regarding copper transport control and turbine fouling prevention.

### 2.8.3 Future R&D

Updating and revision of EPRI's copper guidelines are planned.

## 2.9 Fireside Corrosion of Superheater and Reheater Tubes

### 2.9.1 Description of Problems

Superheater and reheater tube fireside corrosion (also called molten salt attack, coal ash corrosion, or liquid-phase corrosion) is currently not a major problem in U.S. units, which all now have steam temperatures of 1050°F (566°C) or less. However, historically, it was a significant problem for units in the U.S. that operated at one time with steam temperatures above 1050°F (566°C). The shift to lower sulfur coals in the U.S., driven by environmental reasons, has also reduced the severity of this problem in domestic units. However, superheater and reheater fireside corrosion has affected units in the U.K. that burn coals with high fractions of chlorine.

Fireside corrosion generally occurs as the result of the formation of low melting point, liquid phase alkali-iron trisulfates. Flue gas induced erosion may also play a role in removing protective oxides. Impurities in the coal such as Na, K, S and Cl can be a primary determinant of the corrosion rate, while alkaline earth oxides (CaO, MgO) tend to suppress the corrosion. There is a peak in the rate of corrosion in the range of 1200 – 1380°F (650 – 750°C), which has led to placing limits on steam temperatures.

### *2.9.2 Current R&D*

No current R&D on this problem for currently operating boilers was identified. The causes of this type of corrosion in current boilers, and suitable remedies, are considered to be well understood. However, new developmental boilers with higher superheat and reheat temperatures of 1300°F - 1400°F (704°C - 760°C) are being evaluated. It is considered likely that corrosion problems will occur in these boilers as the result of their higher temperatures. R&D is being conducted in connection with a DOE funded program to explore these concerns.

### *2.9.3 Future R&D*

There is an incentive to use higher steam temperatures to achieve higher efficiencies. Higher temperatures, such as the 1300 - 1400°F superheat temperatures being considered as discussed above, are likely to lead to corrosion problems. It is considered desirable to continue to evaluate the problems that might arise and possible ways to address them.

Power producers are experiencing pressure to use alternate fuels for both economic reasons and environmental reasons. These alternate fuels include fuels such as petroleum coke, rubber tires, and biomass, e.g., switch grass and wood chips. The impurities introduced by these alternate fuels could lead to corrosion problems, and it is considered desirable to systematically explore these possible problems and solutions.

## 2.10 Corrosion of Flue Gas Desulfurization (FGD) Equipment

### *2.10.1 Description of Problems*

Corrosion is a relatively minor concern at the current time with FGD systems. It was a serious problem when FGD systems were first introduced in the 1960s and 1970s because of rapid corrosion of the materials originally used, such as carbon steels and conventional stainless steels. However, it appears that the materials selected and applied in the past few decades, such as Hastelloy C-276 and Hastelloy C-22, have generally proven to be satisfactory. However, use of the highly corrosion resistant alloys increases original capital costs and thus increases annual depreciation expenses. In addition, pitting and corrosion continue to affect stainless steels used in FGD systems, and pinhole leaks have developed in “wallpaper” applications of high-nickel alloys.

### *2.10.2 Current R&D*

EPRI has projects directed at determining the causes of corrosion and erosion related failures in high grade FGD alloys, evaluating and/or developing countermeasures (such as use of new coatings), and publishing guidelines for avoiding such problems.

### 2.10.3 Future R&D

Continuation of the R&D described above is considered worthwhile.

## 2.11 Liquid Slag Corrosion of Cyclone Furnace Boilers

### 2.11.1 Description of Problems

A little less than 10% of domestic coal-fired power plant boilers have cyclone furnaces in which liquid slag runs from the furnace into the boiler. The liquid slag can cause corrosion of waterwall tubes. The problem is more severe in boilers that use coal with a high pyrite content. To counteract this problem, most cyclone boilers use low-sulfur coal.

### 2.11.2 Current R&D

A report was issued in October 1999 on this problem (TE-113719). It concluded that the problem can be handled using relatively inexpensive coatings that are currently available.

### 2.11.3 Future R&D

No needed R&D on this problem was identified.

## 2.12 Dew Point (Back-End) Corrosion of Boilers

### 2.12.1 Description of Problems

Dew point corrosion involves the condensation of acidic liquids in the cooler back-end part of the boiler exhaust system. $SO_3$ is a major species causing this type of corrosion. The acidic liquids can cause rapid corrosion of parts wetted by the condensed liquids, such as in economizers, air preheaters, ducts and precipitators. In order to avoid this problem, plants are typically designed and operated to keep the exhaust temperatures above the dew point, and coal impurities may also be limited for the same purpose.[6] These steps minimize corrosion problems, but potentially could increase fuel costs, or decrease plant efficiency and thus increase the capital costs required to achieve a given megawatt output.

### 2.12.2 Current R&D

EPRI has a current project directed at full-scale demonstrations of processes designed to eliminate flue gas $SO_3$ – a leading cause of back-end corrosion and visible plumes. EPRI also has a project directed at developing a more fundamental understanding of how $SO_3$ forms and can be captured. Elimination of $SO_3$ is expected to become more critical in the future as selective catalytic reduction systems are added to plants as part of NOx minimization programs, since these systems tend to double the concentration of $SO_3$ in the stack. The processes being evaluated include furnace injection of alkalis and use of wet electrostatic precipitators.

### 2.12.3 Future R&D

Continuation of the current R&D discussed above is considered worthwhile.

## 2.13 Flow-Accelerated Corrosion (FAC) of Piping and Components

### 2.13.1 Description of Problems

Carbon steel piping and components can experience thinning of up to several millimeters per year as the result of FAC. This problem occurs most often in two-phase flow areas, e.g., in the steam drains, but the most severe cases have been in the single phase feedwater systems between the boiler feedwater pump and the economizer. FAC has caused some serious pipe bursts that have led to fatalities, and as a consequence has led to significant inspections, repairs and replacements. The problem is relatively well understood, and is known to be a function of several variables such as material composition, flow velocity, temperature, pH, and oxidizing potential. Water chemistry changes, such as use of oxygenated water treatment, are known to be useful remedial approaches at fossil plants. FAC applies to both fossil and nuclear plants, but is much more important from a cost standpoint at nuclear plants because of the higher costs of down time, inspections, and repairs at nuclear plants, and since use of oxygen treatment has been judged to be not appropriate for nuclear plants since the level of oxygen is selected to mitigate core and steam generator corrosion issues .

### 2.13.2 Current R&D

EPRI is working at trying to develop an understanding of the two-phase FAC which occurs on the shell side of feedwater heaters and how to deal with it. Using the chemistry solution mentioned above (oxygenated treatment) appears not to work, and other solutions are needed. EPRI supports the CHECUP software, the CHECUP users group, and training programs to help utilities manage FAC issues at fossil plants.

### 2.13.3 Future R&D

Continuation of the current R&D mentioned above is planned.

## 2.14 Service Water and Circulating Water System Piping and Components

### 2.14.1 Description of Problems

A large range of piping materials, ID coatings and linings, OD coatings for buried items, water qualities and treatments, soil qualities, and cathodic protection system designs are used for service water and circulating water systems. Reflecting this range of conditions is a variety of corrosion conditions that result in the need for inspections, repairs and other remedial measures. Some examples follow:

- Much of the service water and circulating water piping is constructed with carbon steel. In freshwater applications it is often unlined on the inside wetted surface. For buried portions of piping, carbon steel is normally coated on the outside, and it is sometimes protected by a cathodic protection system. This type of piping experiences an array of corrosion problems, including MIC attack, pitting, erosion-corrosion, and under-deposit attack from the ID, and (for buried portions) pitting type corrosion at coating defects from the OD.
- In aggressive environments, such as seawater or brackish water, mortar-lined cast iron or carbon steel pipe is often used, although high-molybdenum stainless steel and copper-nickel alloy piping are also used. Mortar-lined piping has often experienced corrosion problems at field-installed joints where the mortar was applied locally after the field structural joint was made. Apparently, the aggressive environment is able to penetrate through defects in the field-made mortar joints and cause corrosion of the pipe structural material, eventually leading to leaks.
- Reinforced concrete pipe that is used for some large diameter piping sometimes suffers from corrosion of the reinforcing steel, similar to problems experienced with other reinforced concrete structures.

While the corrosion problems affecting service water and circulating water systems have the potential for occasionally resulting in large costs, e.g., as the result of causing a plant outage, or because of consequential damage such as flooding of other equipment, the general practice is to repair problems as they occur. Chemical treatment programs are followed in many cases to ameliorate fouling and corrosion, usually with the assistance of chemical company contractors. The overall assessment of personnel experienced with this piping and with the overall maintenance situation at coal-fired power plants is that corrosion costs are moderate and that problems are generally handled with little impact on plant performance. On the other hand, earlier EPRI studies indicate that the costs of chemistry control for these systems could be significantly reduced by detailed evaluation of the programs and competitive bidding for treatment chemicals.

### 2.14.2 Current R&D

Corrosion control using regenerative biofilms (CCURB) is being investigated by an EPRI program. EPRI also has a project to develop nonoxidizing biocides (e.g., use of enzymes and pulsed acoustics) for biofouling control that is directed at reducing thermal performance problems and corrosion problems caused by biofouling, with the intent of providing environmental benefits while maintaining or improving performance.

### 2.14.3 Future R&D

Continuation of the programs mentioned above is considered worthwhile. In addition, based on the earlier study mentioned in 2.14.1, it appears that there is the potential for significant reductions in chemical treatment costs by technical evaluation of treatment programs and competitive procurement of chemicals. It is suggested that providing assistance to utilities in this area via some type of technology transfer mechanism (e.g., workshop, conference or course) be considered.

## 2.15 Oil Tanks and Piping

### *2.15.1 Description of Problems*

Corrosion induced failures in buried oil piping and in oil supply piping in boilers have sometimes resulted in severe problems and very high costs (e.g., a recent failure in a buried oil pipeline resulted in about $100 million in costs). The corrosion occurs from a variety of causes, including corrosion fatigue from the ID at crimps at bends, OD corrosion at defects in the coating of buried piping and tanks, pitting at locations where water collects, etc. While this problem is serious at some plants, it would seem to have limited cost impact overall since only about 3% of electric power is generated using oil. However, its importance may be higher than indicated by this low percentage since there are oil storage and transfer facilities at many plants, even when oil is used only infrequently as a fuel.

### *2.15.2 Current R&D*

No current R&D programs for corrosion problems affecting this equipment in fossil plants were identified.

### *2.15.3 Future R&D*

A utility that recently experienced large costs related to failures in a buried oil pipeline and in fuel oil supply hoses to burners considers that there is a strong need for improved inspection and maintenance methods and guidance. They describe the current situation as being risky for the industry as the result of little attention being paid by either utilities or regulators to oil tanks and piping, coupled with the known ongoing nature of corrosion, and the demonstrated large problems that occasionally result when oil tanks or piping fail. For example, the possibility of oil contamination of water supplies caused by the failure of a large oil storage tank is cited as a serious concern.

## 2.16 Miscellaneous Structural and Mechanical Components

### *2.16.1 Description of Problems*

The environments in many parts of coal-fired power plants can be aggressive. For example, water draining from coal can be acidic and be aggressive towards coal handling equipment. Similarly, wet ash handling systems can experience corrosion problems because of the aggressive nature of wetted ash slurry, especially when it is recycled. Corrosion of reinforced concrete in cooling towers is a severe problem at some plants with saltwater cooling towers. Atmospheric corrosion of general structures can also be a problem as a result of deposited pollutants from the plant. However, these problems are not reported as being severe except on an occasional basis, and are generally handled as a routine maintenance.

### 2.16.2 Current R&D

No current R&D programs for corrosion problems affecting this equipment in fossil plants were identified.

### 2.16.3 Future R&D

Improved methods for controlling the corrosion of reinforced concrete parts in saltwater cooling towers was identified by a utility as warranting R&D.

## 2.17 Summary - Fossil Steam Generation Sector

As shown by the cost estimates in Table 2-2, corrosion costs associated with boiler tube failures dominate corrosion costs for the fossil steam generation. In this regard, four of the first ten items involve boiler tube failures and account for about 38% of the total annual corrosion cost in fossil steam plants.

After boiler tube corrosion problems, turbine corrosion problems have the next largest cost impact. These costs are mainly associated with three types of problems: oxide particle erosion of turbine nozzles and blades, stress corrosion cracking and corrosion fatigue of disks and blades, and copper deposition in high pressure turbines. There are a number of other relatively high cost impact corrosion problems, including corrosion in heat exchangers and electric generator stator cooling water systems.

With regard to R&D and application of corrosion management practices on high cost impact corrosion problems, the following are considered to be the highest priority:

- <u>Waterside Boiler Tube Failure Reduction</u>. The causes of waterside corrosion induced boiler tube failures are well understood, and additional research into the causes is not considered to be of high priority. However, the high costs of the ongoing corrosion problems indicate that the available technology is not being effectively implemented at many plants. Accordingly, high priority needs to be given to assisting power producers to properly implement the already developed technology (e.g., the water chemistry guidelines, the Boiler Tube Failure Book, and the FAC Book).
- <u>Steam Turbine Corrosion-Related Problems</u>. The three main corrosion-related problems affecting steam turbines are oxide particle erosion of nozzles and blades, SCC and CF of disks and blades, and copper deposition in high pressure turbines. The causes of and remedies for these problems are well understood. However, the high costs of the ongoing corrosion problems indicate that the already developed technology is not being properly implemented at many plants. According, high priority needs to be given to assisting power producers to properly implement the already developed technology (e.g., Turbine Steam Path Damage: Theory and Practice, TR-108943, 1999).

- Fireside Boiler Tube Corrosion. Because of continuing pressures to reduce NOx emissions, reducing conditions in boilers are expected to become more severe and more widespread, leading to increased fireside corrosion. It is considered that additional emphasis should be given to projects directed at improving the understanding of how impurities in coal interact and cause fireside corrosion problems, and also on projects directed at developing improved methods to remedy fireside corrosion problems.

  Fireside corrosion problems are likely to worsen when alternative fuels such as petroleum coke, tires and biomass are burned. Since there are environmental, regulatory, and economic pressures to use these alternate fuels, it is considered desirable to systematically explore the effects of these alternate fuels on fireside corrosion and on how to best counter any adverse effects.

- Oil Pipelines and Tanks. Corrosion induced failure of oil transfer and storage equipment was identified by a power producer as having caused high costs at their plants, and as being a source of high risk to all plants with oil storage and transfer equipment. At the plants involved, the specific problems that had occurred were a failure of a buried oil supply pipeline, with large leakage of oil into a public waterway, and two failures of oil burner supply hoses that caused expensive fires. Investigation of the problems indicated that there was little attention being paid by either power producers or regulatory bodies to possible corrosion induced failures of oil tanks, pipelines, and other oil transfer equipment. Investigation also indicated that failures of the equipment pose large risks, such as risks of wide scale environmental contamination of public water sources and waterways by leaks from large oil storage tanks or pipelines. It is considered that research into ways to monitor and control corrosion in oil storage and transfer equipment is warranted.

# 3
# COMBUSTION TURBINE GENERATION SECTOR

This section summarizes information regarding the problems that cause most of the costs of corrosion in the combustion turbine (CT) sector of the electric power industry. This sector includes combined cycle plants that use heat recovery steam generators (HRSGs) and thus covers corrosion problems affecting HRSGs as well as CTs. For each corrosion problem, it summarizes the causes, ongoing R&D, needs for additional R&D, and estimated 1998 costs. The starting point for estimating the costs of the various corrosion problems was the compilation of total corrosion costs for this sector in report 1004662.[1] These costs are shown in Table 3-1 (the numbers were rounded in order to avoid giving an impression of false precision).

O&M costs in the non-direct fuel related category of Table 3-1 are mainly due to costs associated with dealing with corrosion of CT parts, with only a relatively small effect due to corrosion in HRSGs. This reflects the fact that CTs without HRSGs accounted for 8% of the installed generating capacity in the USA in 1998, while combined cycle plants with HRSGs accounted for only 2% (i.e., CTs without HRSGs accounted for 80%of the CT generating capacity in 1998).[7]

Costs in the direct fuel-related corrosion cost category of Table 3-1 are attributed in report 1004662 to purchasing cleaner fuel in order to minimize corrosion problems, and were estimated as being equal to 2% of the total cost of the fuel used by the CT sector. Experts indicate that this is not applicable to natural gas, which has low impurities levels, but that it does apply to oil fuels. In this regard, No. 2 fuel oil is generally used rather than the less expensive No. 6 fuel oil in order to avoid the corrosion problems that would occur if No. 6 fuel oil were used. Considering the fraction of CT power produced using fuel oil in 1999 (about 8%), the fraction of those plants burning oil that use No. 2 fuel oil (92%), and the increased cost of No. 2 fuel oil compared to No. 6 fuel oil (35%), the impact on total fuel cost for the CT sector is about 2.6%, i.e., slightly more than the 2% cited in report 1004662. Because of the roughness of this calculation, the 2% estimate from report 1004662 has been retained.

**Table 3-1**
**Summary of 1998 Corrosion Costs to Consumers for Combustion Turbine Sector**

| O&M Non-Direct Fuel Related Corrosion Cost | O&M Direct Fuel-Related Corrosion Cost | Depreciation Corrosion Cost | Total Corrosion Cost |
|---|---|---|---|
| $98,400,000 | $99,600,000 | $35,700,000 | $233,700,000 |

The following parts of this section discuss the corrosion problems that lead to the most significant O&M and depreciation costs involved in the combustion turbine sector of the industry, including both CTs and HRSGs. These corrosion problems are discussed approximately in the order indicated by the total annual estimated corrosion cost to the nation in 1998, with the costliest problems discussed first. The estimated corrosion costs are shown in Table 3-2 and were developed as discussed in Section 1. Because both the O&M non-direct and O&M direct fuel-related corrosion costs are driven by the same corrosion problems in the CTs (associated with exposure to combustion gases), they are combined for the purposes of this analysis.

Table 3-2 indicates that corrosion costs in HRSGs are lower than for CTs. This mainly reflects the relatively small fraction of the CT generating capacity that includes HRSGs (20%), and also is a result of the young age of most HRSGs. Operators indicate that turbine blade coating degradation and hot corrosion lead to a continuing need for refurbishment of CTs, and thus to high corrosion-related costs. Operators also indicate that, despite their young age, waterside/steamside corrosion is the main cause of HRSG problems.

**Table 3-2**
**1998 Costs of Corrosion Problems Affecting CTs and HRSGs**

| Corrosion Problem | 1998 O&M Corrosion Cost | | 1998 Deprecitation Corrosion Cost | | Total 1998 Corrosion Cost |
|---|---|---|---|---|---|
| | Ranking | Dollars | Ranking | Dollars | |
| All Corrosion Problems in CT Generation Sector | | $198,000,000 | | $35,700,000 | $233,700,000 |
| Hot Corrosion of CT Blades and Vanes | 10 | $82,500,000 | 10 | $10,500,000 | $93,000,000 |
| Hot Oxidation of CT Blades and Vanes | 3 | $24,750,000 | 10 | $10,500,000 | $35,250,000 |
| HRSG Corrosion Fatigue | 2 | $16,500,000 | 3 | $3,150,000 | $19,650,000 |
| HRSG FAC | 1 | $8,250,000 | 2 | $2,100,000 | $10,350,000 |
| HRSG Underdeposit Corrosion | 1 | $8,250,000 | 2 | $2,100,000 | $10,350,000 |
| Corrosion of Compressor Section | 1 | $8,250,000 | 1 | $1,050,000 | $9,300,000 |
| Corrosion of Exhaust Section | 1 | $8,250,000 | 1 | $1,050,000 | $9,300,000 |
| All Other Corrosion Problems | 5 | $41,250,000 | 5 | $5,250,000 | $46,500,000 |
| Sum of Ranking Points | 24 | | 34 | | |

The following portions of this section cover the main corrosion problems affecting CTs and HRSGs, together with discussions regarding current R&D and needs for future R&D.

## 3.1 Hot Corrosion and Oxidation of CT Blade and Vane Materials

### 3.1.1 Description of Problems

Hot corrosion of CT materials is mainly driven by impurities from two sources: impurities in the fuel and impurities introduced with ingested air. Because natural gas has very low levels of impurities, units that use only natural gas as a fuel experience relatively few hot corrosion problems. However, problems due to impurities from the atmosphere occasionally occur in units using natural gas. This is especially the case in units with marine atmospheres. In addition, many natural gas units have a dual fuel capability, and occasionally are tested or operate using an oil such as number 2 distillate fuel. The periods of occasional operation with oil can introduce impurities and hot corrosion problems.

In oil-fired units, Type II corrosion of CT materials occurs at temperatures below about 1450°F (788°C) and Type I occurs in the temperature range of about 1450 - 1600°F (788 - 871°C). These corrosion modes are driven by the presence of impurities such as sulfur, chlorine, alkalis, and vanadium. To protect against these types of hot corrosion, blades and vanes are coated with a variety of materials, such as MCrAlY and MCrAlY covered with an aluminide (where "M" stands for a metal such as nickel or cobalt). Degradation of coatings is a major cause of problems, and inspection and renewal of coatings is a major corrosion related cost of CT operation. Corrosion of the blades and vanes occurs at cracks in the coatings, and the penetration of the corrosion into the blades can limit their reuse and thus their useful life. Because of the high cost of modern blades, reduced lifetimes involve high costs.

In addition to the hot corrosion problems discussed above, high temperature blade and vane materials can be degraded by hot oxidation. This involves direct oxidation of the materials by the environment that does not involve attack by impurities such as alkali sulfides. While not called "corrosion" in the CT industry, hot oxidation nevertheless is considered in this report as a corrosion process since it involves reaction of CT materials with the environment. Hot oxidation is addressed in CTs by use of design features that limit contact between CT materials and hot gases and that limit the metal temperature. These features include methods of cooling the blades such as steam cooling and use of protective coatings. Advanced coatings for new higher temperature CTs include use of thermal barrier coatings (TBC) applied to an inner coating of NiCrAlY. Hot oxidation does not currently result in significant O&M costs since the new higher temperature machines where it could occur are just beginning operation.

### 3.1.2 Current R&D

The high costs of replacement blades for newer high temperature CTs make it important to protect them with coatings, and to accurately predict blade lifetimes and the lifetimes of their protective coatings. EPRI recently issued a report (1006608, February 2002) on this subject that represents the results of a four-year project to develop improved methods for predicting blade lifetime, including coating degradation aspects. EPRI currently has a three-year project to further evaluate coatings, including life prediction and how to inspect coatings.

### 3.1.3 Future R&D

Future concerns and areas regarding CTs warranting R&D follow:

- Degradation of first stage CT turbine blades is a major problem in newer high temperature CTs. This degradation is often aggravated by penetration of impurities through coatings and down grain boundaries. For these reasons, the degradation resistance and breakdown of coatings under a variety of conditions (temperature, impurity type and concentration, etc.) warrant continuing investigation. Aspects that warrant investigation include:
  - How oxidation occurs in coatings, how species from the blade diffuse into the coating and degrade it, etc.
  - Coatings for 2nd and 3rd stage blades and vanes as well as for first stage blades and vanes, since the high temperatures in the first stage can vaporize impurities which then collect on the later stages.
  - How startup and shutdown processes affect the transport and deposition of impurities on blades and vanes.
  - Design and characterization of coatings, e.g., achieving porosity in TBCs to provide thermal resistance while still providing good resistance to penetration by impurities. In this regard, TBCs have become much more important as the result of temperature increases, and thus warrant continuing attention.
- New design CTs are expected to operate in a base load mode, and thus are expected to accumulate operating hours much faster than older CTs. Since they are now depended on for base load power, the need for replacement power when down for maintenance makes them more expensive to maintain than older CTs used only for peaking power. Operation for long periods in a base load manner is expected to result in the appearance of new problems. For this reason, it is considered important to closely monitor and characterize the experience of these new higher temperature CTs right from the start, e.g., for the first 3 to 5 years.
- New design CTs will mainly operate using natural gas, and thus are expected to have few corrosion problems. However, they will occasionally use liquid fuels that can cause deposition of undesirable impurities that can lead to hot corrosion if not removed. Cleaning methods such as use of nut shell washing should be investigated. These methods are often used for marine turbines.
- Replacement costs for CT blades are high. Thus, development of repair methods for CT blades would be worthwhile.
- TBCs have become very important and much more work on them needs to be done. TBCs are mainly intended to protect against hot oxidation, but they must also provide acceptable protection against hot corrosion.
- In the future, syngas will be burned in CTs. This is a dirtier fuel than natural gas, and the impurities in it are likely to lead to problems such as hot corrosion. These problems need to be investigated.

## 3.2 Corrosion Problems Affecting HRSGs

### 3.2.1 Description of Problems

With efficiencies approaching 60%, combined-cycle plants are becoming the generating technology of choice, and most combustion turbine plants built since about 1990 include HRSGs, i.e., are combined cycle plants. Besides efficiency, this technology also offers other advantages over conventional fossil plants, such as cycling and peaking service capability, low operating costs, and reduced emission of greenhouse gases. However, HRSG designs for combined-cycle plants have become increasingly complex over the last ten years. Originally designed to produce steam at one pressure level, today's HRSGs may have three pressure levels with superheat and reheat and may be once-through or combined drum/once-through systems. Many different variations are also available within these basic designs. This increasing level of complexity has been accompanied by numerous failures and operating problems, many of which are influenced by cycle chemistry.

HRSG tube failures (HTF) are the major cause of availability loss and lost capacity for HRSGs. EPRI's latest survey finds that most failures occur in the low-pressure economizer and evaporator, and the high pressure economizer and superheater, followed by the high pressure evaporator. The most predominant failure mechanisms are corrosion fatigue and thermal fatigue followed by FAC and pitting. This analysis also indicates that over 70% of the costs of lost generation are influenced by the cycle chemistry. Currently this is higher than in conventional fossil plants. Failures that have been occurring for many years in conventional plants, such as under-deposit corrosion (hydrogen damage, acid phosphate corrosion and caustic gouging) are already predominant in HRSGs. The major additional HTF mechanism is FAC of evaporator circuits. It is judged to be of paramount importance for successful operation of combined cycle plants that the cycle chemistry is initially selected and subsequently optimized properly, and that operators have full control, and know what to do in emergency chemical situations.

Fireside corrosion is not a serious problem in HRSGs since essentially all CTs with HRSGs use natural gas as the fuel, which has very low impurities.

### 3.2.2 Current R&D

To enable power producers to address the challenges of increasing amounts of corrosion problems in HRSGs, EPRI established the Heat Recovery Steam Generator Dependability Program. Prior to this program, EPRI produced the first comprehensive set of cycle chemistry guidelines for chemists and operators of combined-cycle plants, which delineate how to select the optimum treatment from among the five possible chemistries. Today, the goal of the HRSG program is to address virtually all current industry concerns for HRSGs within combined-cycle plants - thereby providing operators with a complete set of technical tools to improve plant operation, availability, and reliability. Products will include unit-specific chemical treatment methods, optimum approaches to HRSG tube failure prevention and FAC elimination, methodologies for life assessment, and guidance for inspection and NDE. Also included will be monitoring guidelines to improve plant availability and thermal transients, as well as a diagnostic expert system for controlling and maintaining the optimal chemistry for specific units. EPRI also offers customized training programs to provide plant personnel with enhanced strategies and skills for managing these technical areas.

In connection with the above program, EPRI is in the process of developing similar information for HRSG tube failures (HTFs) as for boiler tube failures (BTFs), of the type documented in "Boiler Tube Failures: Theory and Practice," TR-105261, June 1996. The HTF manual will cover failure mechanisms, root causes, and solutions. There are plans to do a limited amount of additional research in these areas, especially with regard to developing a better understanding of the causes of the FAC being observed in HRSGs, and on ways to ameliorate it.

### *3.3.3 Future R&D*

EPRI considers that there are no main corrosion issues affecting HRSGs that have not been studied. However, the ongoing work described above related to assisting utilities select and implement appropriate water chemistry strategies, developing an HTF manual, ameliorating FAC, and developing and using improved NDE methods, will be continued.

## 3.3 Corrosion of CT Compressor Section

### *3.3.1 Description of Problems*

The compressor sections of CTs are made of various grades of low alloy steels and stainless steels. Some of the earlier grades, such as low alloy steels and Type 403 stainless steel, have experienced corrosion problems, especially when exposed to marine environments or polluted fuels. Much of the corrosion is attributed to condensation that occurs during shutdown periods. Recently, improved grades of stainless steel such as Carpenter Custom 450 have been used, and have been found to be less susceptible to compressor section corrosion.

### *3.3.2 Current R&D*

No current R&D on this problem was identified.

### *3.3.3 Future R&D*

No needs for future R&D on this problem were identified.

## 3.4 Corrosion of CT Exhaust Section

### *3.4.1 Description of Problems*

The exhaust sections of CTs involve large ducts with internal and external insulation. Since many units are operated only intermittently, these areas can get wet and experience corrosion during shutdown periods.

### 3.4.2 Current R&D

No current R&D on this problem was identified.

### 3.4.3 Future R&D

Because of the relatively low economic impact of corrosion in the CT exhaust section, R&D regarding this type of corrosion is considered to be unnecessary.

## 3.5 Summary - CTs and HRSGs

New CTs, especially those in combined cycle plants, are now mainly being operated in a base load mode. In addition, the newer units have higher operating temperatures. These two trends - operation in a base load mode and at higher temperature - are expected to result in more severe corrosion problems. Since CTs are being depended upon for an increasing share of electricity generation in the USA, it is important that the performance of the new units be closely monitored and that corrosion problems in these units be promptly addressed as they arise.

Hot corrosion and hot oxidation of CT blades and vanes are currently the dominant causes of corrosion costs in the CT sector and thus warrant a high level of attention. These problems could become more severe if fuel shortages or national energy security considerations lead to the use of dirtier fuels such as syngas or oils. Use of coatings is the main available method for addressing the problems of hot corrosion and hot oxidation. Thus, continued work on improving coatings for current machines, on developing improved coatings for newer higher temperature machines, and on developing coatings to facilitate the use of dirtier fuels is considered to be of high importance. Development of repair methods for corroded blades and vanes would also help to reduce costs.

While HRSGs are currently not a large source of corrosion costs, it is anticipated that they will become more significant as the HRSGs age and as more HRSGs are put into operation. Thus, current efforts to develop an HRSG tube failure (HTF) manual and to assist utilities improve water chemistry practices are important.

# 4
# NUCLEAR POWER GENERATION SECTOR

This section summarizes information regarding the more important corrosion problems that cause much of the cost of corrosion in the nuclear power generation sector of the electric power industry. For each of these corrosion problems, this section summarizes the known causes, ongoing R&D, and needs for future R&D.

The starting point for estimating the costs of the more important corrosion problems was the compilation of corrosion costs for nuclear power in report 1004662.[1] These costs include both O&M and depreciation costs. As indicated in Table 9-1 of report 1004662, the total 1998 corrosion cost to consumers for nuclear power was estimated at $9,300 million. The breakdown of these costs between BWRs and PWRs, and between non-fuel O&M, fuel O&M, lost production and depreciation comes from Sections 4 and 8 of Report 1004662. As shown in Table 4-1 and discussed in report 1004662, the nuclear plant corrosion cost due to lost production is substantial, and is the result of having to provide power from more expensive sources when the nuclear plants cannot produce power as a result of corrosion-induced problems (the numbers in Table 4-1 were rounded in order to avoid giving an impression of false precision).

**Table 4-1**
**Summary of 1998 Corrosion Costs to Consumers for Nuclear Power Sector (Million $)**

| Category | O&M Non-Fuel Corrosion Cost | O&M Fuel Corrosion Cost | Lost Production Cost | Depreciation Corrosion Cost | Total Corrosion Cost |
|---|---|---|---|---|---|
| BWR | 2,302 | 143 | 198 | 465 | 3,108 |
| PWR | 4,400 | 319 | 440 | 1,034 | 6,193 |
| BWR + PWR | 6,702 | 462 | 638 | 1,499 | 9,301 |

As shown in Table 4-1, $3,108 million of the 1998 corrosion cost for nuclear power was attributed to BWRs and $6,192 million was attributed to PWRs. The four parts of these costs (non-fuel O&M costs, fuel O&M costs, costs of lost production, and depreciation) were distributed to specific corrosion problems as discussed below and shown on Tables 4-2 through 4-5. Non-fuel O&M costs and depreciation costs were combined for distribution since they both involve overall plant performance, and were then distributed to specific corrosion problems based on costs for specific O&M activities as discussed below. Fuel and lost production costs were distributed separately to specific corrosion problems to reflect the particular problems contributing to these costs.

The following parts of this section discuss the corrosion problems that lead to the most significant corrosion costs for the nuclear power generation sector of the industry. These corrosion problems are discussed approximately in the order indicated by the total annual estimated corrosion cost to the nation in 1998, with the costliest problems discussed first. The estimated corrosion costs for the more important corrosion problems affecting PWRs and BWRs were developed as follows:

- Tables 3-4 and 3-5 of the Cost of Corrosion in the Electric Power Industry report 1004662,[1] show the percentages of the non-fuel O&M budget that were due to specific activities at PWR and BWR plants, respectively, and also showed the percents of these costs that were due to corrosion. These corrosion costs, except in a few cases, were due to activities involving several corrosion problems. In order to develop estimated costs for specific problems, the costs in Tables 3-4 and 3-5 of report 1004662 were distributed to specific corrosion problems as shown in Tables 4-2 and 4-3 of this report.
- The corrosion costs for fuel and lost production were also distributed to specific corrosion problems as shown in Tables 4-2 and 4-3.
- The estimated total costs attributed to each corrosion problem were then calculated using the distributions of Tables 4-2 and 4-3 and the input costs discussed earlier. The resulting costs are shown on Tables 4-4 and 4-5.
- The distributions of costs to specific corrosion problems shown on Tables 4-2 and 4-3 were made considering several factors. First, distributions of cost from various O&M activities were made considering the types of work performed under the activity account as identified by the utilities that supplied the data. Second, the distributions reflect engineering judgments based on discussions with EPRI and utility experts regarding the relative cost impacts of the different corrosion problems. Third, distributions of lost production costs to specific problems were made considering statistics on causes of forced outages assembled by Hagler Bailly for EPRI.[8]
- Based on the distribution of costs to specific corrosion problems as described in the above steps, the ten most costly corrosion problems, considering BWRs and PWRs together, are shown in Table 4-6. Because of rounding, the dollar amounts in the Corrosion Cost of Activity column may not be exactly equal to the sum of the dollar amounts in the Cost Attributed to Specific Corrosion Problem columns.

**Table 4-2**
**Distribution of 1998 Corrosion Costs to Specific Corrosion Problems - PWRs**

| Corrosion Problems ➔ / Cost Categories ↓ | Percentage of O&M Corrosion Cost | Percent of Item Attributed to Specific Corrosion Problem | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Corrosion Product Activation & Deposition | Steam Generator Tube Corrosion | Corrosion - Service Water System | Heat Exchanger Corrosion | Flow Accelerated Corrosion | CF & SCC of Turbines | PWSCC of Non-SG Alloy 600 Parts | Electric Genenerator Corrosion | Boric Acid Corrosion | Fuel Clad Corrosion | IASCC of Internals | Miscellaneous & General |
| **O&M Activities** | | | | | | | | | | | | | |
| General Maintenance & Maintenance Support Activities | 36.76% | | 10% | 4% | 4% | 4% | 4% | 8% | 2% | 2% | | 2% | 60% |
| Steam Generators- 600MA | 17.84% | | 100% | | | | | | | | | | |
| Control Radiation Exposure & Contamination, Radwaste Disposal, Fuel Pool Cleanout, Health Physics | 17.77% | 100% | | | | | | | | | | | |
| Chemistry | 7.56% | 20% | 35% | 10% | 5% | 5% | 5% | | 5% | | 10% | | 5% |
| Steam Generators- 600TT, 690TT | 3.05% | | 100% | | | | | | | | | | |
| Pipes | 2.69% | | | 25% | | 25% | | | | 10% | | | 40% |
| Coating & Painting | 1.56% | | | | | | | | | | | | 100% |
| Nuclear Inservice Inspection | 1.54% | | | | | 10% | | 30% | | 20% | | 10% | 30% |
| O&M Modifications | 1.43% | | | 10% | 10% | 10% | | | | | | | 70% |
| Instrumentation | 1.19% | | | | | | | | | | | | 100% |
| Heat Exchangers | 1.15% | | | | 100% | | | | | | | | |
| Fuel Handling | 1.01% | 50% | | | | | | | | | | | 50% |
| Heating, Venting, Air Conditioning | 0.99% | | | 20% | | | | | | | | | 80% |
| Electric Components | 0.99% | | | | | | | | | | | | 100% |
| Environmental Management | 0.85% | | 20% | 20% | 10% | 10% | | | | | | | 40% |
| Main Turbines | 0.80% | | | | | | 80% | | | | | | 20% |
| Fuel Engineering | 0.69% | | | | | | | | | | 50% | 10% | 40% |
| Reactor Vessels & Internals | 0.54% | | | | | | | | | | | 50% | 50% |
| Valves | 0.33% | | | 5% | | 5% | | | | | | | 90% |
| Pumps | 0.32% | | | 5% | | 5% | | | | | | | 90% |
| Motors | 0.26% | | | | | | | | | | | | 100% |
| Electric Generators | 0.22% | | | | | | | | 100% | | | | |
| Cooling Towers | 0.21% | | | | | | | | | | | | 100% |
| Diesel Generators | 0.16% | | | | | | | | | | | | 100% |
| Other Turbines | 0.10% | | | | | | | | | | | | 100% |
| | | | | | | | | | | | | | |
| **Fuel** | | | | | | | | | | | 100% | | |
| | | | | | | | | | | | | | |
| **Lost Production** | | | 63% | | | 3% | | 10% | | 5% | | 5% | 14% |

**Table 4-3**
**Distribution of 1998 Corrosion Costs to Specific Corrosion Problems - BWRs**

| Corrosion Problems ➔<br><br>Cost Categories ↓ | Percentage of O&M Corrosion Cost | Percent of Item Attributed to Specific Corrosion Problem | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Corrosion Product Activation and Deposition | IGSCC of Piping & Internals | Heat Exchanger Corrosion | Valves | Corrosion - SWS & CWS | Flow Accelerated Corrosion | Pumps | CF & SCC of Turbines | Electrical Generator Corrosion | Fuel Clad Corrosion | Control Blades | Miscellaneous & General |
| O&M Activities | | | | | | | | | | | | | |
| Control Radiation Exposure & Contamination, Radwaste Disposal, Fuel Pool Cleanout, Health Physics | 37.47% | 100% | | | | | | | | | | | |
| General Maintenance & Maintenance Support Activities | 23.87% | | 5% | 5% | 5% | 5% | 5% | 5% | 5% | 5% | | | 60% |
| Chemistry (Chemicals, Laboratory, Support, Systems Engineering, HWC) | 11.17% | 30% | 40% | 5% | | 5% | 5% | | 5% | | 10% | | |
| Heat Exchangers & Condensers | 8.24% | | | 100% | | | | | | | | | |
| Balance of Plant Preventive and Corrective Maintenance | 3.94% | | | 20% | 10% | 30% | 20% | 10% | | 10% | | | |
| Inservice Inspection | 3.42% | | 80% | | | 10% | 10% | | | | | | |
| Nuclear Research + Dues to Research Organizations | 3.02% | | 60% | | | 10% | 10% | | | | | | 20% |
| NSSS Preventive and Corrective Maintenance | 2.30% | | | 30% | 20% | | | 20% | | | | | 30% |
| Valves - Corrective & Preventive Maintenance, Spare Parts | 2.26% | | | | 100% | | | | | | | | |
| Control Blades | 1.15% | | | | | | | | | | | 100% | |
| Electrical Work | 0.59% | | | | | | | | | | | | 100% |
| I&C corrective and Preventive Maintenance | 0.54% | | | | | | | | | | | | 100% |
| Pumps - Spare Parts and Corrective Maintenance | 0.51% | | | | | | | 100% | | | | | |
| Metallurgical Program | 0.45% | | 10% | 20% | 10% | 20% | 20% | 10% | 10% | | | | |
| Turbines | 0.31% | | | | | | | | 75% | | | | 25% |
| Diesel Generators | 0.31% | | | | | | | | | | | | 100% |
| Containment Inspection | 0.29% | | | | | | | | | | | | 100% |
| Piping | 0.10% | | | | | 40% | 40% | | | | | | 20% |
| Circulating Water Maintenance | 0.04% | | | | | 100% | | | | | | | |
| | | | | | | | | | | | | | |
| Fuel | | | | | | | | | | | 100% | | |
| | | | | | | | | | | | | | |
| Lost Production | | | 40% | | | | 19% | | | | 7% | | 34% |

**Table 4-4**
**1998 Corrosion Costs of Specific Corrosion Problems - PWRs (Million $)**

| | | Cost Attributed to Specific Corrosion Problem | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Corrosion Problems ➔<br>Cost Categories ➔ | Corrosion Cost of Activity, Million $ | Corrosion Product Activation and Deposition | Steam Generator Tube Corrosion | Corrosion - Service Water System | Heat Exchanger Corrosion | Flow Accelerated Corrosion | CF & SCC of Turbines | PWSCC of Non-SG Alloy 600 Parts | Electric Generator Corrosion | Boric Acid Corrosion | Fuel Clad Corrosion | IASCC of Internals | Miscellaneous & General |
| **O&M Activities** | | | | | | | | | | | | | |
| General Maintenance & Maintenance Support Activities | 1997 | | 200 | 80 | 80 | 80 | 80 | 160 | 40 | 40 | | 40 | 1198 |
| Steam Generators- 600MA | 969 | | 969 | | | | | | | | | | |
| Radiation Protection, Decontamination & Waste Disposal | 965 | 965 | | | | | | | | | | | |
| Chemistry | 410 | 82 | 144 | 41 | 21 | 21 | 21 | | 21 | | 41 | | 21 |
| Steam Generators- 600TT, 690TT | 166 | | 166 | | | | | | | | | | |
| Pipes | 146 | | | 37 | | 37 | | | | 15 | | | 59 |
| Coating & Painting | 85 | | | | | | | | | | | | 85 |
| Nuclear Inservice Inspection | 83 | | | | | 8 | | 25 | | 17 | | 8 | 25 |
| O&M Modifications | 78 | | | 8 | 8 | 8 | | | | | | | 54 |
| Instrumentation | 65 | | | | | | | | | | | | 65 |
| Heat Exchangers | 62 | | | | 62 | | | | | | | | |
| Fuel Handling | 55 | 28 | | | | | | | | | | | 28 |
| Heating, Venting, Air Conditioning | 54 | | | 11 | | | | | | | | | 43 |
| Electric Components | 54 | | | | | | | | | | | | 54 |
| Environmental Management | 46 | | 9 | 9 | 5 | 5 | | | | | | | 18 |
| Main Turbines | 43 | | | | | | 35 | | | | | | 9 |
| Fuel Engineering | 37 | | | | | | | | | | 19 | 4 | 15 |
| Reactor Vessels & Internals | 29 | | | | | | | | | | | 15 | 15 |
| Valves | 18 | | | 1 | | 1 | | | | | | | 16 |
| Pumps | 17 | | | 1 | | 1 | | | | | | | 16 |
| Motors | 14 | | | | | | | | | | | | 14 |
| Electric Generators | 12 | | | | | | | | 12 | | | | |
| Cooling Towers | 12 | | | | | | | | | | | | 12 |
| Diesel Generators | 9 | | | | | | | | | | | | 9 |
| Other Turbines | 5 | | | | | | | | | | | | 5 |
| | | | | | | | | | | | | | |
| **Fuel** | 319 | | | | | | | | | | 319 | | |
| | | | | | | | | | | | | | |
| **Lost Production** | 440 | | 277 | | | 13 | | 44 | | 22 | | 22 | 62 |
| | | | | | | | | | | | | | |
| **Totals** | 6192 | 1075 | 1765 | 187 | 175 | 173 | 135 | 229 | 73 | 93 | 379 | 89 | 1820 |

**Table 4-5**
**1998 Corrosion Costs of Specific Corrosion Problems - BWRs (Million $)**

| | | Cost Attributed to Specific Corrosion Problem | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Corrosion Problems ➔<br>Cost Categories<br>🡣 | Corrosion Cost of Activity, Million $ | Corrosion Product Activation and Deposition | IGSCC of Piping & Internals | Heat Exchanger Corrosion | Valves | Corrosion - SWS & CWS | Flow Accelerated Corrosion | Pumps | CF & SCC of Turbines | Electrical Generator Corrosion | Fuel Clad Corrosion | Control Blades | Miscellaneous & General |
| O&M Activities | | | | | | | | | | | | | |
| Control Radiation Exposure & Contamination, Radwaste Disposal, Fuel Pool Cleanout, HP | 1037 | 1037 | | | | | | | | | | | |
| General Maintenance & Maintenance Support Activities | 660 | | 33 | 33 | 33 | 33 | 33 | 33 | 33 | 33 | | | 396 |
| Chemistry (Chemicals, Laboratory, Support, Systems Engineering, HWC) | 309 | 93 | 124 | 15 | | 15 | 15 | | 15 | | 31 | | |
| Heat Exchangers & Condensers | 228 | | | 228 | | | | | | | | | |
| Balance of Plant Preventive and Corrective Maintenance | 109 | | | 22 | 11 | 33 | 22 | 11 | | 11 | | | |
| Inservice Inspection | 95 | | 76 | | | 9 | 9 | 0 | | | | | |
| Nuclear Research + Dues to Research Organizations | 84 | | 50 | | | 8 | 8 | | | | | | 17 |
| NSSS Preventive and Corrective Maintenance | 64 | | | 19 | 13 | | | 13 | | | | | 19 |
| Valves - Corrective & Preventive Maintenance, Spare Parts | 63 | | | | 63 | | | | | | | | |
| Control Blades | 32 | | | | | | | | | | | 32 | |
| Electrical Work | 16 | | | | | | | | | | | | 16 |
| I&C corrective and Preventive Maintenance | 15 | | | | | | | | | | | | 15 |
| Pumps - Spare Parts and Corrective Maintenance | 14 | | | | | | | 14 | | | | | |
| Metallurgical Program | 12 | | 1 | 2 | 1 | 2 | 2 | 1 | 1 | | | | |
| Turbines | 9 | | | | | | | | 7 | | | | 2 |
| Diesel Generators | 9 | | | | | | | | | | | | 9 |
| Containment Inspection | 8 | | | | | | | | | | | | 8 |
| Piping | 3 | | | | | 1 | 1 | | | | | | 1 |
| Circulating Water Maintenance | 1 | | | | | 1 | | | | | | | |
| | | | | | | | | | | | | | |
| Fuel | 143 | | | | | | | | | | 143 | | |
| | | | | | | | | | | | | | |
| Lost Production | 198 | | 79 | | | | 38 | | | | 14 | | 67 |
| | | | | | | | | | | | | | |
| Totals | 3108 | 1129 | 363 | 320 | 120 | 104 | 129 | 72 | 56 | 44 | 188 | 32 | 550 |

**Table 4-6**
**1998 Corrosion Costs of the Ten Most Costly Corrosion Problems - BWRs + PWRs (Million $)**

| Corrosion Problem | BWR | PWR | Total |
|---|---|---|---|
| Corrosion Product Activation & Distribution | 1,129 | 1,075 | 2,205 |
| Steam Generator Tube Corrosion | | 1,765 | 1,765 |
| Fuel Clad Corrosion | 188 | 379 | 567 |
| Heat Exchanger Corrosion | 320 | 175 | 495 |
| IGSCC of Piping & Internals | 363 | | 363 |
| Flow Accelerated Corrosion | 129 | 173 | 302 |
| Corrosion - SWS & CWS | 104 | 187 | 291 |
| PWSCC of Non-SG Alloy 600 Parts | | 229 | 229 |
| CF & SCC of Turbines | 56 | 135 | 191 |
| Corrosion in Electric Generators | 44 | 73 | 116 |

## 4.1 Corrosion Product Activation and Deposition

### *4.1.1 Description of Problem*

High costs are incurred at nuclear power plants as a result of the accumulation and activation of corrosion products in the reactor core and the subsequent distribution of these activated materials around the reactor coolant system. Dealing with this distributed radioactivity leads to many costs, including the need for complex radiation protection programs, shielding, use of remote equipment, implementation of as low as reasonably achievable (ALARA) programs, needs for decontamination, needs for disposal of radioactive waste, etc. The root cause of most of the problem is the release of corrosion products from wetted structural materials into flow streams leading to the reactor core, although some contribution also comes from materials introduced by valve seat grinding and similar maintenance activities. The isotopes that cause the most problem are cobalt-59, which is activated to cobalt-60, and nickel-58, which is activated to cobalt-58. Cobalt is a trace or tramp element commonly found in stainless steels and nickel alloys, and is the major alloying element of many common hardfacing materials, such as Stellite™.

Some nuclear power experts have expressed surprise at the high fraction of the nuclear power O&M costs attributed to corrosion product activation and deposition, and have questioned the reasonableness of this fraction. In response, it is noted that the ranking of corrosion product activation and deposition as the corrosion process leading to the highest costs at nuclear plants is based on cost data from accounting records maintained by utilities, coupled with their assessment of these costs being mainly due to corrosion. These costs are given in the appendices of report 1004662.[1] The cost categories (or "work activities") involved included radiation protection, control of radiation exposure, control of radioactive contamination, decontamination, radioactive waste disposal, fuel pool cleanup, and chemistry control. Most of the costs in these work activity accounts were considered by the utilities to be caused by corrosion (e.g., due to activated corrosion products), and they assigned corrosion percentages of 90 to 100%. These two factors (high accrued costs for the work activities caused by activated corrosion products, and the high corrosion factors of 90 to 100%), resulted in making the corrosion costs for corrosion product activation and deposition higher than any other single problem in the nuclear power sector.

A related consideration is that the costs for corrosion product activation and deposition given in report 1004662[1] are probably significantly underestimated (as opposed to over estimated) since they do not include the indirect costs associated with the higher cost of repairs and maintenance caused by having to do work in high radiation and contamination environments. In reality, much of the cost of general maintenance, valve repairs, pump repairs, inservice inspection, etc., could be assigned to corrosion product activation and deposition since the radiation fields and contamination from activated corrosion products greatly increase the difficulty and cost of these tasks.

### 4.1.2 Current R&D

Research directed at reducing the costs associated with activation and deposition of corrosion products has been extensive, and has included activities such as development of (1) low cobalt hardfacing alloys and guidelines for minimizing the use of high cobalt materials in nuclear plants, (2) use of materials with reduced cobalt concentrations for replacement steam generators and other components (e.g., use of lower cobalt stainless steel to fabricate BWR control blade components), (3) surface treatments that reduce the pickup of activated materials from the reactor coolant system (RCS), especially electropolishing, (4) water chemistry practices directed at minimizing deposition of corrosion products in the core, and also minimizing their release and deposition around the RCS, (5) methods for decontaminating systems and equipment, and (6) methods for more efficiently and cost effectively treating and disposing of radioactive waste.

There are several water chemistry R&D projects underway that are directed at helping control corrosion product activation, distribution and deposition around the RCS, while at the same time addressing other objectives such as minimizing fuel clad corrosion, axial offset anomaly (AOA), PWSCC of Alloy 600, and IGSCC of stainless steels. These include evaluating the effects of high pH operation, zinc addition, use of enriched boric acid, and noble metal chemical addition (NMCA). Preliminary indications are that use of ultrasonic cleaning of fuel will be helpful at reducing shutdown dose rates as well as at addressing the AOA problem.

EPRI has an active program directed at helping utilities minimize costs of dealing with low level waste. This program provides software and other guidance to help utilities apply existing technology in the most cost effective manner. In addition, EPRI works with utilities to evaluate new technologies. For example, projects are underway regarding evaluation of improved processing of liquid waste steams, such as using advanced polymer treatment, nuclide-specific removal techniques, and advanced membrane techniques.

### 4.1.3 Future R&D

EPRI and industry experts identified the following as being important R&D that should be conducted to reduce corrosion costs in this area:

- Development of more corrosion resistant fuel cladding that allows use of water chemistry conditions (e.g., higher pH) that reduce corrosion rates of structural materials. This would reduce dose rates by reducing the input of corrosion products to the core.
- Evaluation of whether it is practical to use electropolishing of the ID surfaces of Alloy 690 thermally treated (TT) steam generator tubes. It is known that electropolishing strongly reduces pickup of activated species by RCS surfaces. However, its effects on thermal hydraulic performance, corrosion processes (especially nickel release), and tube manufacturing processes need to be evaluated.
- Evaluation of applying EPRI's "Stabilized Chromium Process" (a three step process consisting of electropolishing, electroplating a thin (~3000 Angstrom thick) chromium layer, and preoxidation) to steam generator channel heads, divider plates, and tube IDs to reduce pickup of activated corrosion products and possibly to mitigate PWSCC.
- Evaluation of the potential for using higher levels of zinc in BWRs to further suppress dose rates, and evaluation of the benefits of noble metal chemical addition in conjunction with zinc at suppressing dose rates.
- Development of ultrasonic cleaning methods for BWR fuel (to date, it has only been used for PWR fuel).
- Evaluation of the use of enriched boric acid (EBA) in PWRs to allow operation with low lithium concentrations to minimize the potential for fuel cladding corrosion, while still permitting operation at high constant $pH_T$ levels (~7.4) to reduce corrosion product release.

## 4.2 Intergranular Attack and Stress Corrosion Cracking (IGA/SCC) of PWR Steam Generator Tubes

### 4.2.1 Description of Problem

Corrosion of steam generator tubes, especially intergranular attack/stress corrosion cracking (IGA/SCC) of mill annealed Alloy 600 (600MA) tubes from the secondary side, has been a major problem in the industry. It has led to extensive inspections and repairs of affected plants, the need for extensive plant design and operating practice changes to significantly improve water chemistry practices, and the replacement of steam generators at many plants. There have been numerous EPRI projects directed at dealing with and ameliorating the problem, including projects directed at helping utilities (1) upgrade and control water chemistry so as to minimize the occurrence of corrosion problems, (2) modify existing steam generators to reduce the rate of corrosion (e.g., by in situ stress relief), (3) perform remedial actions such as chemical cleaning, (4) perform inspections and repairs more accurately, efficiently, and cost effectively, and with optimized repair criteria, and (5) obtain more resistant tubing and steam generator design features in replacement steam generators.

Concerns about possible corrosion of steam generator tubes in replacement steam generators with thermally treated Alloy 600 (600TT) or Alloy 690 (690TT) tubes results in significant costs even though there has been essentially no corrosion in the USA of replacement tubes of these materials. Most of these costs are associated with performing frequent periodic inspections and maintaining tight water chemistry. This is a result of stringent inspection and water chemistry requirements -- developed to deal with the serious corrosion problems experienced with Alloy 600MA tubes -- having been carried over to steam generators with the new tube materials.

### 4.2.2 Current R&D

There is a large Steam Generator Management Program (SGMP) that addresses all aspects of the steam generator tube corrosion problem. Current R&D in this area covers many topics, including water chemistry improvements, FAC and fouling evaluations, corrosion tests of Alloy 690TT, NDE method and guideline development, thermal hydraulic analyses and upgrades, structural integrity guideline revisions, etc. Included in the SGMP are projects directed at quantifying the increased corrosion resistance of steam generators with Alloy 600TT and Alloy 690TT tubes and modern design features, and assisting utilities take advantage of this increased corrosion resistance by reducing inspection requirements and, possibly, water chemistry control requirements.

### 4.2.3 Future R&D

Future R&D directed at reducing steam generator tube corrosion costs that is considered worthwhile but that has not as yet been funded include the following:

- Additional investigation of the possible effects of startup oxidants on IGA/SCC. Research to date has provided the basis for modeling oxidation/reduction of deposits during layups and start ups, but additional testing and plant trials would be useful to develop firm conclusions regarding the effects of startup oxidants on IGA/SCC.
- Model boiler tests by the French Commissariat à l'Energie Atomique (CEA) have shown that reduced sulfur produced by the combination of sodium sulfate and hydrazine can lead to IGA/SCC of Alloy 600MA similar to that seen in plants. However, insufficient testing and analysis has been performed to determine if the current levels of sulfate and hydrazine entering steam generators (e.g., 2 ppb sulfate and 100 ppb hydrazine in the blowdown) are sufficient to cause or aggravate the IGA/SCC. Thus, tests and analyses to quantify the effects of reduced sulfur would be desirable.
- Model boiler tests by CEA and autoclave tests by numerous laboratories have shown that small amounts of lead can cause IGA/SCC of Alloy 600MA. However, insufficient quantification of the concentrations of lead that are actually present in steam generator crevice solutions has been done to determine if the lead is a significant cause of the observed IGA/SCC. Additional quantification of the concentrations of lead in crevice solutions, and the effects of these concentrations on IGA/SCC, would be worthwhile to help determine if additional countermeasures against lead (such as more frequent checks of lead levels in the feedwater, especially during startup) would be useful.

- Tests in all-volatile treatment (AVT) solutions result in cracking of highly stressed reversed U-bend (RUB) samples after about 22,000 hours at 288°C. Extrapolations of these results to lower stress levels result in predicted times to cracking in non-concentrated AVT water occurring only after very long times have been accumulated, e.g., over a million hours. However, non-concentrated AVT solutions are low in conductivity, and it is likely that IGA/SCC is accelerated as conductivity increases. It is possible that much of the IGA/SCC seen in plants is simply the result of the increases in concentration and conductivity associated with deposits and crevices. To explore this possibility, it would be desirable to conduct tests to determine the effects of conductivity at constant $pH_T$ on the occurrence of IGA/SCC. If high conductivity was determined to be an important factor, this could lead to changes in remedial approaches, such as further reductions of impurity ingress vs. use of molar ratio control.
- There are economic incentives to relax NDE requirements and water chemistry requirements for steam generators with Alloy 690TT and Alloy 600TT tubing. To support such relaxations, it would be useful to show that 690TT and 600TT have large improvement factors in terms of time to cracking as compared to 600MA in relevant environments. Current programs of testing and analysis have shown that 690TT and 600TT are considerably more resistant to IGA/SCC in many environments than 600MA. However, tests in the most relevant near neutral environments with lead, sulfur and complex environments have not been carried out long enough, nor with enough intermediate inspections, to positively demonstrate large factors of improvement for the time to occurrence of IGA/SCC. It would desirable to conduct tests for longer times and with sufficiently frequent inspections to develop firm demonstrations of large improvement factors.

## 4.3 Corrosion of Fuel Cladding

### *4.3.1 Description of Problem*

Several serious fuel failures have occurred over the past few years. However, the direct costs involved with these occasional fuel failures, while substantial for the individual utilities involved, are not a large part of the total fuel clad corrosion cost to the industry. The main costs, that affect all utilities, are those engendered by the need to limit burnups and local power levels to minimize risks of fuel failure caused by either OD or ID corrosion, and by the need to limit local power levels to minimize boiling-caused crud depositions and either under deposit corrosion or AOA.

Current BWR fuel problems include:

- Secondary degradation, where an initial clad penetration (e.g., due to foreign material) leads to internal hydriding and large splits in the clad, out of which fuel material spills. This causes significant contamination problems.
- Pellet clad interaction (PCI), which appears to have become active again as a result of changes made to barrier cladding in response to the secondary degradation problem.
- Crud induced fuel failures.

- Concerns associated with use of the noble metal chemical addition (NMCA) process, including uncertainty regarding whether deposits on fuel applying NMCA are associated with crud or with oxides. The deposits or oxides associated with NMCA have not led to fuel failures or operating limits thus far, but could possibly limit going to higher burnups.

Current PWR concerns and research are focused on avoidance of axial offset anomaly (AOA), and on use of advanced cladding materials to allow higher burnups without exceeding the 100 μm oxide thickness limit established to ensure satisfactory accident performance.

### 4.3.2 Current R&D

Current R&D is being conducted in the context of the Robust Fuel Program. This is a large program with many projects, including (1) projects to explore effects of high burnups and corrosion on the properties of various types of cladding and fuel assembly components, (2) hot cell examinations to evaluate the mechanisms involved in fuel failures, (3) development of strategies to mitigate PWR crud and AOA, and (4) evaluation of the failure mechanism involved in secondary degradation in BWRs and development of strategies to mitigate it.

### 4.3.3 Future R&D

Considering the large costs attributed to fuel burnup limits caused by clad corrosion concerns, it seems reasonable to investigate whether systematic investigations should be undertaken by EPRI to develop improved fuel clad materials that would allow higher burnups to be achieved, rather than relying solely on fuel vendors to do so. Up to now, EPRI has concluded that it is not practical for EPRI to undertake such a widescale cladding development program. However, EPRI experts indicated that, from an overall industry standpoint, it seems as though it would be worthwhile.

## 4.4 Heat Exchanger Corrosion

### 4.4.1 Description of Problem

There are a number of corrosion related problems that affect nuclear and fossil plant heat exchangers such as condensers, feedwater heaters, service water heat exchangers, lube oil coolers, component cooling water heat exchangers, and residual heat removal heat exchangers. These problems are listed below. Prioritizing the problems in order of cost impact was not possible because sufficient details regarding the specific causes of heat exchanger costs were not available.

- Inlet end erosion-corrosion of copper alloy tubes
- Sulfide attack of copper alloy tubing in polluted waters
- FAC or erosion-corrosion of carbon steel tubing and supports
- Stress corrosion cracking of stainless steel tubing and some types of copper alloy tubing

- Pitting and under-deposit corrosion of copper alloy, carbon steel, and stainless steel tubing
- MIC attack of copper alloy, carbon steel and stainless steel tubing
- Hydriding of titanium tubing
- Galvanic corrosion of carbon steel water boxes and tube sheets and copper alloy tube sheets
- Dealloying of copper alloy tube sheets and graphitization of cast iron waterboxes

These problems result in occasional leaks, sometimes cause forced outages or power reductions, and often require inspections, repairs and other remedial actions. Dealing with the problems is especially costly when they occur in nuclear safety related equipment.

### 4.4.2 Current R&D

EPRI projects in this area are mainly directed at holding workshops to foster information exchanges among utilities and EPRI experts, especially with regard to inspection methods. There appears to be no active research being conducted regarding causes of the problems nor regarding remedies other than inspection and repair.

### 4.4.3 Future R&D

No specific needs for R&D on heat exchanger corrosion problems were identified in discussion with EPRI and utility experts, other than the need for continuing to work on improving NDE methods and on information exchange regarding how to cost effectively deal with corrosion problems. However, because of the high costs being incurred as a result of heat exchanger corrosion, it is suggested by the report author that consideration be given to further work on better identification of the causes of the problems, development of practical remedies, and technology transfer activities to make sure that the lessons learned are effectively implemented.

## 4.5 Intergranular Stress Corrosion Cracking (IGSCC) of Piping and Internals at BWRs

### 4.5.1 Description of Problem

IGSCC of stainless steel piping in BWRs was a large problem in the late 1970s and through the 1980s. The IGSCC is a result of the susceptibility of austenitic stainless steel to intergranular corrosion when sensitized and exposed to BWR reactor coolant environments operated with normal water chemistry. With normal water chemistry, BWR reactor coolant has enough oxygen (~200 ppb) to make it oxidizing enough to cause intergranular corrosion of sensitized stainless steels and also of sensitized Alloy 600. In response to the piping IGSCC problem, an array of remedies was developed, including replacement of susceptible piping, use of induction heat stress improvement (IHSI), heat sink welding, adoption of hydrogen water chemistry, and reduction of impurity levels in the reactor coolant. As a result of the application of these remedies the occurrence of IGSCC in BWR piping is now relatively rare. In addition, because of improved inspection practices (as well as reduced crack initiation and growth rates), IGSCC in BWR piping generally is detected and corrected before it causes serious problems.

In the 1990s, IGSCC of stainless steel and Alloy 600 parts in the reactor internals emerged as a major problem in BWRs. The BWR Vessels and Internals Project (BWRVIP) was initiated in 1994 to develop remedies and help the industry deal with the problem. The BWRVIP program is continuing and has many active projects, with six program areas.

### 4.5.2 Current R&D

As noted above, the BWRVIP program has an array of projects underway directed at various aspects of the reactor internals IGSCC problem. These are: (1) an Improved Materials Performance Program directed at developing tools for evaluating the condition of the reactor vessel and components, (2) a Fluence Evaluation Methodology project to develop standardized methods for performing fluence calculations, (3) an Improved NDE Program directed at developing NDE techniques that allow faster and more accurate inspections, (4) a Condition Assessment Guides Program to develop guidelines for inspection, repair and remediation, (5) an Integrated Surveillance Program that integrates surveillance capsule results for all BWRs, and (6) a SCC Mitigation Guidelines Program to provide utilities with methods for reducing or eliminating IGSCC. Of these projects, the one most directly related with corrosion science and corrosion prevention is the SCC Mitigation Guidelines project. The objective of this project is to optimize use of hydrogen water chemistry (HWC), noble metal chemical addition (NMCA), and depleted zinc in order to reduce IGSCC while at the same time minimizing shutdown dose rates, fuel crud problems, and costs.

### 4.5.3 Future R&D

No needed R&D beyond that described in the current BWRVIP program was identified.

## 4.6 Flow-Accelerated Corrosion (FAC) of Piping and Components

### 4.6.1 Description of Problem

Carbon steel piping and components in PWRs and BWRs can experience thinning of up to several millimeters per year as the result of flow-accelerated corrosion (FAC). This problem is most severe in two phase flow areas, e.g., in the steam drains and moisture separator reheaters, but also can occur in single phase condensate and feedwater systems. It has caused some serious pipe bursts, and as a consequence has led to significant inspections, repairs and replacements. The problem is relatively well understood, and is known to be a function of several variables such as material composition, flow velocity, temperature, pH, and oxidizing potential. Water chemistry changes, such as increasing pH, are known to be useful remedial approaches. FAC applies to both fossil and nuclear plants, but is much more important from a cost standpoint at nuclear power plants because of the higher costs of down time, inspections, and repairs at nuclear plants.

### 4.6.2 Current R&D

The main current R&D project on FAC is obtaining improved data regarding the effects of hydrazine and oxygen on FAC, and integrating this information into the CHECWORKS code.

### 4.6.3 Future R&D

Tests performed by Electricité de France indicate that high hydrazine can aggravate FAC under some situations. Developing a clear understanding of the effects of hydrazine over the full range of conditions seen in PWR systems, including in steam generators, would be useful in order to aid in balancing the benefits of hydrazine for control of corrosion in steam generators against its deficits regarding FAC.

## 4.7 Raw Service Water and Circulating Water System Piping and Components

### 4.7.1 Description of Problem

There are many different corrosion related problems that affect raw water service piping and components. This reflects the large array of piping and heat exchanger materials, ID coatings and linings, OD coatings for buried items, water qualities, soil conditions and types, and cathodic protection system designs that are used for service water and circulating water systems. Some examples of corrosion problems affecting raw water systems follow:

- In aggressive raw water environments, such as seawater or brackish water, mortar lined cast iron or carbon steel pipe is often used, although high molybdenum stainless steel is also used, as is copper-nickel alloy piping. Mortar lined carbon steel or cast iron piping has often experienced corrosion problems at field-installed joints where the mortar was applied locally after the field structural joint was made. Apparently, the aggressive environment is able to penetrate through defects in the field-made mortar joints and cause corrosion of the pipe structural material, eventually leading to leaks.
- Much of the service water and circulating water piping is constructed with carbon steel. In freshwater applications it is often unlined on the inside wetted surface. This type of piping experiences several types of corrosion problems, including MIC attack, pitting, erosion-corrosion, and under-deposit attack.
- Under-deposit pitting problems affect piping and heat exchanger tubing, including pipe and tubing made of copper alloys, carbon steel and stainless steel. There often is MIC involvement.
- Fouling by Asiatic clams and zebra mussels is a frequent problem. While the fouling itself is not a corrosion problem, the fouling can lead to under-deposit corrosion.
- OD localized corrosion occasionally occurs at flaws (holidays) in the OD coating used on buried carbon steel piping.

- Reinforced concrete pipe that is used for some large diameter piping sometimes suffers from corrosion of the reinforcing steel, similar to problems experienced with other reinforced concrete structures.

Many of the corrosion problems affecting raw service water systems are handled on a repair-as-needed basis when problems are detected. However, since these problems have sometimes posed risks to the operability of nuclear safety related systems, formal programs have been established at nuclear power plants to monitor and deal with these problems before they raise risks of inoperability of nuclear safety related systems.

### 4.7.2 Current R&D

EPRI manages the Service Water Assistance Program (SWAP) that compiles experience and technology reports on service water programs, and assists utilities evaluate problems. Yearly conferences are held covering issues such as causes of problems, mitigating actions, inspection method development, and repair experiences.

A life cycle management demonstration project was recently completed covering several systems and components, including buried raw water piping. In addition, a sourcebook covering buried piping has recently been issued by EPRI.

Current research topics include:

- Use of selected bacteria and enzymes to counter deposition of organisms and the potentially adverse effects of biofilms.
- Use of furanone compounds to discourage bacterial films from forming. This type of compound is produced, for example, by seaweed.

### 4.7.3 Future R&D

The high priority projects for next year for service water piping have not been finalized by EPRI but probably will include (1) buried pipe condition assessment and life projection and, in the longer term, how to deal with or ameliorate the corrosion problems described in Section 4.7.1, and (2) development of recommendations that cover where to look for corrosion damage in service water systems, how to look, how to select sample areas for inspection, and what types of corrective actions to take considering the results of the inspections.

## 4.8 Primary Water Stress Corrosion Cracking (PWSCC) of Alloy 600 Type Materials (Non-Steam Generator) in PWRs

### 4.8.1 Description of Problem

Primary water stress corrosion cracking (PWSCC) is occurring in Alloy 600 base material and welds at an increasing rate as plants age. Initially, PWSCC affected mainly steam generator tubes. Next, it was detected in Alloy 600 base materials in components such as pressurizer instrument nozzles and reactor vessel head control rod drive mechanism (CRDM) penetrations. In the past several years, PWSCC cracks have been detected in hot leg reactor vessel nozzle welds and in reactor vessel head penetration welds. The sizes, locations, orientations, and rates of growth of some recently observed cracks, and the consequential damage in terms of wastage of low alloy steel parts caused by the cracks, have resulted in an increased level of concern with this problem.

### 4.8.2 Current R&D

Because of the seriousness of the problems associated with the recent occurrences of PWSCC in hot leg nozzles and reactor vessel heads, a large program of R&D is underway. Much of the current R&D is focused on developing cost effective ways to inspect for and remediate the PWSCC. Projects are also nearing completion that assess how reactor coolant water chemistry affects the initiation of PWSCC, and the influence of zinc additions on PWSCC initiation and growth.

### 4.8.3 Future R&D

Tests performed by government laboratories have shown that Alloy 82 weld metal is susceptible to low temperature crack propagation (LTCP) as a result of hydrogen in the water. This has raised concerns that LTCP could aggravate PWSCC induced cracks in welds in PWRs. Research to better define this problem, and to determine if it also applies to Alloy 182, is planned.

Additional work to better define how hydrogen concentration during high temperature operation affects PWSCC initiation and growth is needed. Currently, judgments are made largely based on extrapolation of data obtained at higher temperatures (320 - 360°C), and it is uncertain how reliable these extrapolations are down to service temperatures ≤ 300°C.

## 4.9 Stress Corrosion Cracking and Corrosion Fatigue in Turbines

### 4.9.1 Description of Problem

SCC of turbine discs occurs at several locations, including at the central holes where discs are shrunk on to rotors (the SCC occurs typically at keyholes), at high stress locations along the disc face, and at blade attachments (often called rim cracking). Both SCC and CF affect turbine blades. SCC and CF of turbine discs and blades result in significant expenditures for periodic inspections and repairs, and for occasional replacements of rotors. There has been extensive work to determine the causes of the SCC and CF that affect turbine disks and blades, e.g., regarding how they vary as a function of turbine materials and steam system chemistry, and to develop inspection and remediation methods. The mechanical aspects of these problems are now well understood and under control. However, the corrosion and electrochemical aspects of the problem are not well understood and are the subject of current R&D.

### 4.9.2 Current R&D

EPRI has ongoing projects to better understand the causes of SCC in turbines and to identify the most cost effective remedies, especially for attachment areas, blade profiles, and rim cracking. This includes a program directed at developing an improved understanding of the electrochemistry in the areas of the turbine where SCC and CF occur. It is expected that this will result in improved guidance as to how to optimize chemistry to minimize SCC and CF in turbines, and also regarding how to optimize turbine designs to minimize development of aggressive conditions.

Development of repair methods for corrosion damage of turbine parts is underway at the EPRI NDE Center. This includes development of weld repair methods using variable composition welds, with the early layers being compatible with the turbine parts and the outer layers having an improved composition for SCC resistance.

Another current EPRI program related to this area is the Nuclear Steam Turbine Generator Initiative. This program is developing analysis tools to assist utilities perform life cycle management of all aspects of turbine generator aging, including corrosion induced problems such as SCC and CF of disks and blades.

### 4.9.3 Future R&D

No needs for additional R&D were identified by EPRI experts or utility engineers, other than for continuing the current R&D described above.

## 4.10 Corrosion in Electric Generators

### 4.10.1 Description of Problems

Several decades ago, SCC of electric generator end rings was a major problem. This problem has largely been brought under control by replacement of the more susceptible end ring materials of 18% manganese - 5% chromium steel with 18% manganese - 18% chromium steel, and by periodic inspection and repair programs. Nevertheless, the need for continuing inspections and occasional repairs result in some continuing significant costs. Recently, cracks have been observed in at least four cases in end rings made of the new 18% manganese - 18% chromium steel. This may result in the need for increased inspection and maintenance, and the need for research to identify the causes and remedies.

There are currently two significant corrosion problems in large, water-cooled electric generators. One is clip-to-strand corrosion of older GE generators that were fabricated using a copper -5% phosphorus braze alloy. EPRI research has shown that reducing oxygen to low levels can control the corrosion. However, GE has indicated that it does not agree, and there has not been much utility acceptance of the EPRI proposed solution. Rather, utilities seem to be accepting the GE proposed repair/replacement approach, which, while expensive (about $5 million per generator), is believed to result in a permanent long term repair. The second problem affecting water-cooled electric generators is flow restrictions (plugging of the hollow strands or clogging of the strainers) in the stator cooling water system. Research indicates that the cause of the plugging/clogging problem is the occurrence in plants of intermediate oxygen levels between the recommended either fully aerated or fully deaerated conditions, and that improved control of oxygen levels will help prevent the problem in both aerated and deaerated systems. Results suggest that a move from recommended dissolved oxygen levels can be tracked relatively easily by monitoring the electrochemical corrosion potential (ECP) but this method is not currently in use. There is also evidence that increasing the pH of the stator cooling water to about 8.0 to 8.5 can control plugging and clogging but this approach is not widely used. Furthermore, this approach is not recommended for units that are susceptible to the clip-to-strand crevice corrosion problem, described above, because higher pH values are predicted to promote the crevice corrosion.

### 4.10.2 Current R&D

As noted above, recent research has been directed at developing a better understanding of, and solutions for, the clip-to-strand corrosion and clogging/plugging problems that are affecting water cooled generators.

### 4.10.3 Future R&D

R&D directed at developing an understanding of the causes of the cracks seen in new 18-18 end rings seems warranted. In addition, in order to help utilities avoid plugging and clogging problems by better control of the water chemistry conditions in their electric generators, it would be desirable to develop a practical method to monitor the ECP in the generator stator cooling water system. It also seems worthwhile to investigate further the use of high-pH stator cooling water to circumvent the plugging and clogging problems.

## 4.11 Corrosion Problems Affecting Valves

### 4.11.1 Description of Problem

Corrosion of valves was identified in the Cost of Corrosion in the Electric Power Industry report 1004662 as a major cause of corrosion induced costs for BWRs, but was considered a relatively minor problem by the PWR utility that performed the study.[1] The BWR utility involved indicated that corrosion caused significant amounts of valve maintenance and repair, e.g., because of damage to seating and sealing surfaces. In this regard, the BWR utility estimated that about 20% of the O&M costs for valves was due to corrosion, while the PWR utility estimated that only 2% of their valve costs were due to corrosion.

### 4.11.2 Current R&D

No active R&D was identified regarding valve corrosion problems.

### 4.11.3 Future R&D

The high level of expenditures on valve corrosion problems, especially at BWRs, indicates that some R&D would be worthwhile to explore the reasons for these costs, and possible ways to reduce them.

## 4.12 Irradiation Assisted Stress Corrosion Cracking (IASCC) of Reactor Internals

### 4.12.1 Description of Problem

Irradiation assisted stress corrosion cracking (IASCC) is the occurrence of SCC in parts exposed to high neutron fluence occurring at higher rates and lower stress levels than would be the case in non-irradiated environments. It affects highly stressed parts, such as PWR baffle bolting, most strongly, but also may be a factor in the IGSCC of lower stressed parts such as core shrouds. IASCC was identified as a high cost corrosion problem for PWRs in the Cost of Corrosion in the Electric Power Industry report 1004662, but was not separately called out as a corrosion cost for BWRs.[1] Nevertheless, it is considered that the problem also affects BWRs and is a contributing factor to the occurrence of IGSCC in BWR reactor internals.

### 4.12.2 Current R&D

EPRI is coordinating a large international program directed at developing an understanding of the causes of IASCC, how to predict its occurrence, and how to mitigate it.

### 4.12.3 Future R&D

No research in addition to that already included in the current program was identified as being needed.

## 4.13 Boric Acid Corrosion of Carbon and Low Alloy Steels in PWRs

### 4.13.1 Description of Problem

Boric acid corrosion is included in this list of important corrosion problems affecting nuclear power plants because the detection of a large area of wastage in the reactor vessel head at Davis Besse in March 2002 has brought this problem to the forefront. This event may result in concerns about this type of wastage having a large impact on costs at many PWRs. Additional background on this problem is covered below.

Plant experience and laboratory tests have shown that boric acid solutions leaking from the PWR reactor coolant system can cause rapid wastage of low alloy and carbon steel. Plant experience and laboratory test results, and guidance for dealing with possible reactor coolant system leaks, are contained in EPRI's Boric Acid Corrosion Guidebook, which was recently updated. Costs due to this problem have not been separately itemized by utilities and problem-specific costs for this item have not been identified. However, performance of inspections each outage per commitments made in response to NRC Generic Letter 88-05 on this topic involve substantial costs, and repairs to some areas that have suffered wastage have been substantial. In this regard, as mentioned earlier, a large wastage hole was recently discovered in the reactor vessel head of Davis Besse where leakage had occurred at a PWSCC crack in an Alloy 600 control rod drive mechanism (CRDM) penetration.

### *4.13.2 Current R&D*

As mentioned above, the Boric Acid Corrosion Guidebook has recently been updated. In addition, in response to the Davis Besse event, extensive modeling is underway to try to better define the processes by which wastage progresses at leaking penetrations, and how the rate of wastage varies as leak flow rates vary.

### *4.13.3 Future R&D*

It is likely that tests will be required to verify and complement the analyses that are being done to quantitatively model the wastage observed at Davis Besse.

## 4.14 Summary - Nuclear Power Generation Sector

The current management structure for identifying, reviewing and prioritizing R&D in the nuclear generation sector has resulted in a well organized and effective program for addressing the problems affecting nuclear plants, including corrosion problems. Nevertheless, this review, which addresses R&D needs from a corrosion cost perspective, does point out a few areas where some additional work may be warranted. The most significant of these areas are the following:

- Despite the very large reductions that have been achieved in dose rate reduction in recent years, the most significant cause of corrosion costs in the nuclear power generation sector is activation and spread of corrosion products. This conclusion is reached based on identified direct costs associated with dealing with radioactivity and with chemistry controls to minimize it. If indirect costs caused by the inefficiencies and difficulties of performing repairs and maintenance were included, the cost assigned to activation and spread of radioactive corrosion products would be increased. Because of the large costs associated with activation and spread of corrosion products, it seems that it would be worthwhile to evaluate whether additional emphasis should be placed on the programs underway to better understand the mechanisms involved and on the programs underway directed at ameliorating the problem.
- The second most important cause of corrosion cost in the nuclear power generation sector is steam generator tube corrosion. Despite extensive research over the years, the specific causes of the IGA/SCC that dominates the problem are not firmly understood. Since, in the long term, these same, as yet undefined causes, could affect replacement steam generators, additional research into the causes of IGA/SCC seems important. This research could, for

example, systematically evaluate the influence of conductivity, low levels of lead, low levels of reduced sulfur, and low levels of alumino silicates on the occurrence of IGA/SCC.

- The third most important cause of corrosion costs in the nuclear power generation sector is fuel clad corrosion. At present, the industry relies on fuel vendor initiatives to develop more corrosion resistant cladding. Considering the high costs involved, it seems that an industry-sponsored effort to systematically explore and develop improved cladding should be considered.
- It appears that heat exchanger and valve corrosion problems are causes of significant corrosion costs, but that no current R&D is being directed at identifying and ameliorating their causes. It is considered that some effort should be directed at assessing whether R&D would be worthwhile directed at developing a better understanding of the causes of these problems and how to most cost effectively deal with them.
- As discussed in the earlier parts of this section, there are several other items that are considered to warrant additional R&D, such as (1) developing an improved understanding of the effects of hydrazine on FAC so that its benefits for ameliorating steam generator corrosion can be better balanced against its adverse FAC effects, (2) evaluating how important LTCP is with regard to propagation of PWSCC cracks in Alloy 600 type weld metal, (3) the influence of hydrogen concentrations at lower reactor coolant temperatures on PWSCC initiation and growth, and (4) testing to better define the mechanisms and rates of boric acid corrosion of carbon and low alloy steel parts due at leaks in Alloy 600 penetrations.

# 5
# TRANSMISSION AND DISTRIBUTION SECTORS

This section summarizes information regarding the problems that cause most of the costs of corrosion in the transmission and distribution (T&D) sectors of the electric power industry. For each corrosion problem it summarizes the causes, ongoing R&D, needs for additional R&D, and estimated 1998 corrosion costs. The starting point for estimating the costs of the various corrosion problems was the compilation of total corrosion costs for these sectors in report 1004662.[1] These costs are shown in Table 5-1 (the numbers were rounded in order to avoid giving an impression of false precision).

**Table 5-1**
**Summary of 1998 Corrosion Costs to Consumers for Transmission and Distribution Equipment**

| | O&M Corrosion Cost | Depreciation Corrosion Cost | Total Corrosion Cost |
|---|---|---|---|
| Transmission | $122,600,000 | $107,000,000 | $229,600,000 |
| Distribution | $317,800,000 | $463,900,000 | $781,700,000 |

The following parts of this section discuss the corrosion problems that lead to the highest O&M and depreciation costs involved in the transmission and distribution sectors of the industry. They are discussed first for the transmission sector, and then for the distribution sector, in the order indicated by their total annual estimated corrosion cost to the nation in 1998, with the costliest problems discussed first. The estimated corrosion costs are shown in Tables 5-2 and 5-3 and were developed as described in Section 1. With regard to the importance of the corrosion problems affecting the transmission and distribution sectors, discussions with EPRI experts indicate that several corrosion problems in the transmission sector are of current concern and are receiving R&D attention, but that corrosion concerns are not significant nor receiving special attention in the distribution sector.

**Table 5-2**
**1998 Costs of Corrosion Problems Affecting the Transmission Sector**

| Corrosion Problem | O&M Corrosion Cost | | Depreciation Corrosion Cost | | Total Corrosion Cost |
|---|---|---|---|---|---|
| | Ranking | Dollars | Ranking | Dollars | |
| All Corrosion Problems | | $122,600,000 | | $107,000,000 | $229,600,000 |
| Corrosion of tower footings | 5 | $24,039,216 | 5 | $20,980,392 | $45,019,608 |
| Corrosion of anchor rods | 3 | $14,423,529 | 3 | $12,588,235 | $27,011,765 |
| Corrosion of tower structures | 3 | $14,423,529 | 3 | $12,588,235 | $27,011,765 |
| Conductor deterioration | 2 | $9,615,686 | 2 | $8,392,157 | $18,007,843 |
| Corrosion of splices | 1 | $4,807,843 | 1 | $4,196,078 | $9,003,922 |
| Corrosion of shield wires | 1 | $4,807,843 | 1 | $4,196,078 | $9,003,922 |
| Corrosion of substation equipment | 0.5 | $2,403,922 | 0.5 | $2,098,039 | $4,501,961 |
| All other corrosion problems | 10 | $48,078,431 | 10 | $41,960,784 | $90,039,216 |
| Sum of ranking points / check totals | 25.5 | | 25.5 | | |

**Table 5-3**
**1998 Costs of Corrosion Problems Affecting the Distribution Sector**

| Corrosion Problem | O&M Corrosion Cost | | Depreciation Corrosion Cost | | Total Corrosion Cost |
|---|---|---|---|---|---|
| | Ranking | Dollars | Ranking | Dollars | |
| All Corrosion Problems | | $317,800,000 | | $463,900,000 | $781,700,000 |
| Corrosion of concentric neutrals | 5 | $72,227,273 | 5 | $105,431,818 | $177,659,091 |
| Corrosion of underground vault equipment | 4 | $57,781,818 | 4 | $84,345,455 | $142,127,273 |
| Atmospheric corrosion of enclosures | 3 | $43,336,364 | 3 | $63,259,091 | $106,595,455 |
| All other corrosion problems | 10 | $144,454,545 | 10 | $210,863,636 | $355,318,182 |
| Sum of ranking points / check totals | 22 | | 22 | | |

## 5.1 Corrosion of Transmission Tower Footings

### 5.1.1 Description of Problems

There are several types of footings used with transmission towers, including reinforced concrete footings and coated steel pilings. Attachment bolts are generally used to connect the towers to the footings. Coatings are used to protect against corrosion of the footings, but cathodic protection generally is not used. Corrosion of the footings is a major problem, and is the result of normal corrosion of steel parts that are exposed to subsurface or surface environments. Typically, there are inspection programs involving random digs, with inspections being performed every 1 to 10 years. When problems are detected, repairs are performed as necessary.

### 5.1.2 Current R&D

There are no current programs directed at managing corrosion of tower footings.

### 5.1.3 Future R&D

Corrosion of tower footings is a major problem that warrants attention. Programs to develop guidance on identification and management of footing corrosion problems are judged to be needed.

## 5.2 Corrosion of Transmission Tower Anchor Rods

### 5.2.1 Description of Problems

Tower guy wires are attached to anchor rods, which suffer from corrosion. If the guy wire support system fails, e.g., due to anchor rod corrosion, the tower falls over.

### 5.2.2 Current R&D

EPRI is working on development of ultrasonic methods for checking the condition of anchor rods.

### 5.2.3 Future R&D

A number of projects are being considered regarding methods for anchor rod assessment.

## 5.3 Corrosion of Transmission Tower Structures

### *5.3.1 Description of Problems*

Transmission towers are generally made of structural steel that has been galvanized or otherwise coated, or of Corten type weathering steel, and are subject to corrosion from exposure to the atmosphere. Preventive maintenance (e.g., inspections to verify coating integrity, recoating as needed, and repairs of the structure itself when necessary) is the key to controlling corrosion damage and is a large expense. This type of preventive maintenance often gets deferred, with unfortunate consequences, such as the corrosion progressing to the point where structural repairs are required, rather than merely recoating.

Towers made of Corten steel are not coated, but rather rely on development of a protective film based on its alloy content. However, these towers are experiencing corrosion problems at bolted joints since Corten does not develop a good protective film at such joints. Extensive crevice corrosion can occur with the production of voluminous corrosion products, which leads to distortion of the joint and, in some cases, rupture of the bolts.

### *5.3.2 Current R&D*

EPRI research in this area involves performance of accelerated tests in an exposure chamber of a variety of steel grades with different coatings and joints, and with aerated and non-aerated soils. A project is being initiated on structural steel management: how to inspect, rank corrosion severity, and assess remedial actions. In addition, there is a tailored collaboration project on evaluation of tar coatings for the entire structure (not just underground).

### *5.3.3 Future R&D*

No needed additional research was identified other than continuation of the current R&D projects mentioned above.

## 5.4 Deterioration of Transmission Conductors

### *5.4.1 Description of Problems*

Transmission system cables typically include both steel and aluminum wires. The steel wires take the load, and the aluminum wires carry the current. Corrosion of the cables occurs at low points (sags) between the towers, and at connections at the towers. Vibration of the wires wears away the galvanized coatings on the steel, especially at attachments. Water collects under attachments. These factors lead to localized corrosion of the steel wires (especially after the original galvanized coating is consumed, and especially if the water has picked up atmospheric pollutants), and can lead to mechanical failure of the cable. Another type of problem is that transmission cables normally have splices every mile or two. Moisture penetrates into and collects in these splices and causes corrosion problems that can reduce conductivity across the splice and lead to overheating and loss of electrical continuity.

### 5.4.2 Current R&D

Electro-magnetic acoustic transducer (EMAT) inspection techniques are being developed for conductors and ground wires. Areas with potential thinning or splice damage are identified for further inspection and, if needed, repair.

### 5.4.3 Future R&D

No needed additional research was identified other than continuation of the current R&D project mentioned above.

## 5.5 Corrosion of Transmission Shield Wires

### 5.5.1 Description of Problems

Transmission lines include shield wires strung above the conductor wires to provide lightening protection. The shield wires are galvanized steel, and are subject to corrosion from the atmosphere and from water collecting on the wires at sags and under attachments. The corrosion is aggravated by pollutants in the water picked up from the atmosphere. The corrosion can lead to failure of the shield line, leading to loss of protection and possibly to shorting of the transmission lines.

### 5.5.2 Current R&D

No current R&D of this problem was identified.

### 5.5.3 Future R&D

No needs for future R&D of this problem were identified.

## 5.6 Corrosion of Transmission System Substation Equipment

### 5.6.1 Description of Problems

Substations include transformers and other equipment on footings, metal enclosures, and grounding systems. In addition, substations are often protected by chain link security fences. All of this equipment is subject to atmospheric corrosion. However, the problem is less severe than with the towers, primarily because of less vibration, and also because the equipment is more accessible for maintenance.

### 5.6.2 Current R&D

No current active R&D of substation corrosion problems was identified. However, EPRI has a Substation Operations & Maintenance Program that addresses all aspects of substation maintenance, including corrosion problems. Also, EPRI has developed several reports that address substation maintenance, including corrosion problems (e.g., Reliability Centered Maintenance for Substations, TR-106418, and Guidelines for the Life Extension of Substations, TR-105070-R1CD).

### 5.6.3 Future R&D

No needs for future R&D of substation corrosion problems were identified.

## 5.7 Corrosion of Distribution System Concentric Neutrals

### 5.7.1 Description of Problems

Corrosion of concentric neutrals in buried unjacketed distribution cables arose as a major issue several decades ago, and several EPRI reports on the problem were issued, e.g., EL-4042, May 1985 and TR-100379, April 1992. Since that time, there has been no EPRI research on the problem. New residential cables are jacketed, and thus are not susceptible to corrosion of concentric neutrals. While there are many older unjacketed cables still in operation, and while corrosion of the concentric neutrals of these unjacketed cables continues to occur, utilities apparently have the needed technology to deal with the problem on a routine basis, e.g., monitor and replace as needed.

### 5.7.2 Current R&D

No current R&D of this problem was identified.

### 5.7.3 Future R&D

No needs for future R&D of this problem were identified by EPRI or utility experts. However, the high costs assigned to this problem in Table 5-3 indicate that more detailed review of this problem may be warranted to determine if additional cost reduction methods are needed and practical.

## 5.8 Corrosion of Distribution System Underground Vault Equipment

### 5.8.1 Description of Problems

There is a considerable amount of distribution equipment located in underground vaults, including circuit breakers, switches, transformers, etc. In addition, cable containing pipe conduits penetrate the vaults. The vaults may be filled or partially filled occasionally with ground waters. In some many cases, the water entering the vaults can be quite corrosive due to the presence of salt and other species from sources such as marine atmospheres, road salt, and fertilizers. There are a variety of corrosion problems that affect the vaults and the equipment contained in them, including corrosion of the rebar in the vault itself, corrosion of the housings of the equipment in the vault (especially corrosion of transformer tanks), and corrosion of the pipe conduit where it is connected to the vault. Corrosion problems, especially of transformer tanks, can be aggravated by galvanic coupling with bare concentric neutrals of attached cables. Coatings, cathodic protection, and automatic drainage systems are used to combat these corrosion problems. However, corrosion can occur despite use of these preventive methods, e.g., corrosion of conduit can occur in the vault wall, apparently because cathodic protection is less effective in that shielded area. The corrosion of the vaults and equipment results in significant costs for inspections, maintenance and repairs, and also occasionally leads to outages. These problems are more important in seacoast areas as the result of higher chloride contamination in these areas.

### *5.8.2 Current R&D*

Recently completed work has included identification of candidate coating systems for use in providing improved coatings for transformer tanks, and testing of guided ultrasonic methods for inspecting conduit attached to the vault. No current R&D specifically directed at corrosion problems was identified. However, corrosion is one of many issues dealt with in EPRI's ongoing "Distribution Reliability Initiative," which covers maintenance, inspection, condition assessment and diagnostic techniques.

### *5.9.3 Future R&D*

No needs for future R&D of this problem were identified by EPRI or utility experts. However, the high costs assigned to this problem in Table 5-3 indicate that more detailed review of this problem may be warranted to determine if additional cost reduction methods are needed and practical.

## 5.9 Atmospheric Corrosion of Electrical Enclosures

### *5.9.1 Description of Problems*

Corrosion of electrical enclosures occurs as the result of exposure to atmospheric conditions. This requires that periodic inspections, maintenance and repairs be performed.

### *5.9.2 Current R&D*

No current R&D of this problem was identified.

### 5.9.3 Future R&D

No needs for future R&D of this problem were identified by EPRI or utility experts. However, the high costs assigned to this problem in Table 5-3 indicate that more detailed review of this problem may be warranted to determine if additional cost reduction methods are needed and practical.

## 5.10 Summary - Transmission and Distribution

Corrosion of transmission tower footings and anchor rods, and of the structures themselves, results in significant costs, and projects for assessing and addressing these corrosion problems are underway. Corrosion of conductors also results in substantial costs, and new NDE methods are being developed to help monitor this corrosion.

Corrosion in distribution systems does not seem to be resulting in any specific identifiable major problems that were identified by either EPRI or utility personnel as warranting R&D. However, the high costs involved indicate that more detailed review of these problems may be warranted to determine if additional cost reduction methods are needed and practical.

# 6
# SUMMARY AND CONCLUSIONS

The cost data developed in the previous sections for the corrosion problems affecting the various sectors of the electric power industry are compiled in Table 6-1. Where the corrosion problems in the fossil and nuclear sectors were the same, they were added together into one item. The compiled costs were then sorted, with the higher costs listed first. The enumerated costs total about $11.7 billion – approximately 76% of the total cost of corrosion for 1998 of $15.4 billion. In this regard, the total cost of corrosion reported in report 1004662[1] of $17.3 billion was reduced to $15.4 billion to correct for deletion of an assumed 2% increase in fuel cost for coal to minimize corrosion in boilers that was assumed when developing report 1004662. As discussed in Section 2, detailed evaluation in this current study indicates that this increase in cost does not in fact occur. The balance of the corrosion cost (about $4.2 billion) is considered to be due to many miscellaneous less costly corrosion problems.

As shown in Table 6-1, corrosion costs in the nuclear power and fossil steam power sectors dominate corrosion costs in the electric power industry. The very large cost problems in the nuclear and fossil sectors at the top of the list are considered to warrant extensive attention. The corrosion costs of some distribution, transmission and combustion turbine sector problems are also large – in the hundred million dollars per year range – and thus also warrant attention.

Detailed discussions of the items listed in Table 6-1 are contained in the preceding sections of this report. The summary given below is limited to discussion of the 15 most costly corrosion problems listed in Table 6-1.

**Table 6-1**
**1998 Costs of Corrosion - Problems from All Sectors**

| Corrosion Problem | Sector | 1998 Corrosion Cost |
|---|---|---|
| Corrosion Product Activation & Deposition | Nuclear | $2,204,574,623 |
| Steam Generator Tube Corrosion | Nuclear | $1,764,556,909 |
| Waterside Corrosion of Boiler Tubes | Fossil | $1,144,000,000 |
| Heat Exchanger Corrosion | Fossil+Nuclear | $855,450,000 |
| Turbine CF & SCC | Fossil+Nuclear | $791,750,000 |
| Fuel Clad Corrosion | Nuclear | $566,514,464 |
| Corrosion in Electric Generators | Fossil+Nuclear | $447,900,000 |
| Flow Accelerated Corrosion | Fossil+Nuclear | $422,150,000 |
| Corrosion of SWS, CWS, & Other Raw Water Systems | Fossil+Nuclear | $411,150,000 |
| IGSCC of Piping & Internals | Nuclear | $363,056,931 |
| Oxide Particle Erosion of Turbines | Fossil | $360,450,000 |
| Fireside Corrosion of Waterwall Tubes | Fossil | $325,950,000 |
| PWSCC of Non-SG Alloy 600 Parts | Nuclear | $228,812,944 |
| Corrosion of Concentric Neutrals | Distribution | $177,659,091 |
| Copper Deposition in Turbines | Fossil | $148,700,000 |
| Fireside SH & RH tubes | Fossil | $148,700,000 |
| Corrosion of Underground Vault Equipment | Distribution | $142,127,273 |
| Corrosion of FGD system | Fossil | $131,450,000 |
| Corrosion in Valves | Nuclear | $120,480,811 |
| Liquid Slag Corrosion of Cyclone Boilers | Fossil | $120,150,000 |
| Backend Dew Point Corrosion | Fossil | $120,150,000 |
| Atmospheric Corrosion of Enclosures | Distribution | $106,595,455 |
| Hot Corrosion of CT Blades and Vanes | CT | $93,000,000 |
| Boric Acid Corrosion of CS & LAS Parts | Nuclear | $93,000,000 |
| IASCC of Reactor Internals | Nuclear | $89,000,000 |
| Corrosion in Pumps | Nuclear | $72,000,000 |
| Corrosion of Tower Footings | Transmission | $45,019,608 |
| Hot Oxidation of CT Blades and Vanes | CT | $35,250,000 |
| Corrosion of BWR Control Blades | Nuclear | $32,000,000 |
| Corrosion of Anchor Rods | Transmission | $27,011,765 |
| Corrosion of Tower Structures | Transmission | $27,011,765 |
| HRSG Corrosion Fatigue | CT | $19,650,000 |
| Conductor Deterioration | Transmission | $18,007,843 |
| HRSG FAC | CT | $10,350,000 |
| HRSG Underdeposit Corrosion | CT | $10,350,000 |
| Corrosion of Compressor Section | CT | $9,300,000 |
| Corrosion of Exhaust Section | CT | $9,300,000 |
| Corrosion of Splices | Transmission | $9,003,922 |
| Corrosion of Shield Wires | Transmission | $9,003,922 |
| Corrosion of Substation Equipment | Transmission | $4,501,961 |
| | | |
| Total of Listed Corrosion Problems | | $11,715,089,284 |

## 6.1 Summary Comments Regarding Top 15 Corrosion Problems

- Corrosion Product Activation and Deposition. This corrosion problem is identified as the most costly to the electric power industry. It affects all nuclear power plants. The costs are incurred in work activities such as radiation protection, radioactive waste disposal, decontamination, and primary coolant chemistry control. It is likely that the costs caused by this problem are actually significantly under-reported since the reported costs for this problem do not reflect the increased costs of doing maintenance and repairs on items like valves, pumps, and piping that are caused by the presence of high radiation and contamination levels.

  Because the industry and EPRI have long recognized the importance of reducing the activation and deposition of corrosion products, there have been and continue to be many active research projects directed at ameliorating this problem, as discussed in Section 4.1. In addition, as also discussed in Section 4.1, EPRI has identified several additional tasks for the future to help further ameliorate the problem. The main conclusions from this project are that (1) the R&D planned by EPRI is clearly warranted by the high costs associated with the problem and, (2) considering the high cost associated with this mode of corrosion, increased funding and acceleration of the work might be warranted.

- PWR Steam Generator Tube Corrosion. This is the second most costly corrosion problem in the industry. As discussed in Section 4.2, EPRI has had, and continues to have, a large R&D program addressing the causes of the problem and ways to cope with its consequences. Efforts to identify and eliminate the causes of steam generator tube corrosion – corrosion of Alloy 600 mill annealed tubes from both the ID and OD surfaces – have not been fully successful, and corrosion continues to occur. Nevertheless, ways to deal with the corrosion so that it does not unduly interfere with plant operation have been developed. The steam generator tube corrosion problem is expected to decrease in significance as susceptible steam generators are replaced by units with more corrosion resistant alloys. Nevertheless, because of the current high costs, and the incentive to ensure that similar problems do not develop in replacement steam generators, additional R&D seems warranted as discussed in Section 4.2.

- Boiler Tube Waterside/Steamside Corrosion. Waterside/steamside corrosion in fossil steam power plants is the largest cause of boiler tube failures and also the largest cause of forced loss of production in these plants. The causes of the waterside/steamside corrosion problems, and solutions to them, have largely been identified by previous EPRI programs, as discussed in Section 2.2. Nevertheless, lost production due to boiler tube failures appears to be increasing. This situation is attributed to effects of deregulation, such as changes in corporate culture and loss of experienced personnel resulting in less careful attention to water chemistry control. EPRI has an active program underway in the technology transfer area that is directed at changing corporate culture and training personnel, with the objective of improving water chemistry practices and reducing waterside/steamside corrosion. Considering the high costs associated with this problem, continuing and perhaps expanding or accelerating this program appears warranted.

- Heat Exchanger Corrosion. Corrosion in heat exchangers continues to result in high costs at both nuclear and fossil plants. As discussed in Sections 4.4 and 2.5, there are many different corrosion mechanisms involved. This is a result of the large range of materials and service conditions present in the heat exchangers used at power plants. In the past, in the late 1970s and early 1980s, there were many projects directed at identifying and correcting the causes of the heat exchanger corrosion problems. However, at present, current EPRI activities are mainly directed at inspection and maintenance aspects, and not at the causes of the corrosion. Considering the high costs involved in heat exchanger corrosion, it is judged that it would be useful to perform detailed surveys of the causes of the corrosion costs, and to then assess whether additional work on developing remedies is needed, or whether additional technology transfer is warranted to better apply already developed remedies.

- <u>Stress Corrosion Cracking (SCC) and Corrosion Fatigue (CF) in Turbines</u>. SCC and CF continue to result in large costs at both nuclear and fossil plants. Mechanical aspects of the problems are mostly understood, and remedial approaches for dealing with these mechanical aspects have been developed. However, the costs of implementing the remedial measures are substantial, and electrochemical aspects of the problems are not thoroughly understood. EPRI has several projects underway to better understand and address these problems, as discussed in Section 2.3 and 4.9. Considering the high costs involved, continuation of these projects is judged to be well worthwhile.
- <u>Fuel Cladding Corrosion</u>. Restrictions on fuel burnup and local power levels are imposed to keep the corrosion of fuel cladding in nuclear plants to acceptable values. These limitations on burnup and local power level result in significant costs. As discussed in Section 4.3, there is a large EPRI program directed at addressing fuel corrosion problems (the Robust Fuel Program), e.g., via improved primary chemistry regimes. In addition, fuel vendors have introduced new cladding materials that provide increased resistance to corrosion. Continuation of these efforts is judged to be warranted. In addition, because of the large costs involved, it is suggested that the possibility be investigated of EPRI leading an effort to systematically explore and develop improved cladding alloys, rather than leaving this solely to fuel vendor initiatives.
- <u>Corrosion in Electric Generators</u>. Corrosion in electric generators is discussed in Sections 2.7 and Section 4.10. The main corrosion problems are clip-to-strand corrosion in older GE generators, and clogging/plugging of the stator water cooling systems in generators of several manufacturers. In addition, some costs are incurred associated with end ring inspections for SCC, and occasional occurrences of SCC in the end rings. Solutions to these problems have been developed but some costs and problems remain. Additional work is recommended regarding investigation of a few cases of cracking experienced with the new 18-18 end ring material, and also regarding developing an ECP monitoring approach for ensuring that oxygen and hydrogen in the stator water cooling system are under proper control.
- <u>Flow-Accelerated Corrosion (FAC)</u>. This problem is covered in Section 2.13 for fossil plants and Section 4.6 for nuclear plants. The problem is more severe at nuclear plants for several reasons. First, nuclear plants have more wet two-phase system piping and components. Second, parts of the final feedwater system that are experiencing FAC in nuclear plants are nuclear safety related and located in containment, making inspections and repairs much more costly. Finally, many fossil plants have adopted oxygenated water treatment, which significantly reduces rates of FAC. The main area considered to warrant further R&D for nuclear plants is to better determine how hydrazine, which is kept at relatively high levels to protect steam generator tubes from corrosion, affects the rate of FAC in different parts of the systems.

- Corrosion of Raw Water Piping. This problem is covered in Sections 2.14 for fossil plants and 4.7 for nuclear plants. The systems are similar at the two types of plants, but the problem results in much higher costs at nuclear plants than fossil plants because many of the affected systems are nuclear safety related. This requires that higher levels of system operability be maintained, resulting in increased inspection, maintenance and repair costs. As discussed in Section 4.7, there are several areas of active and planned research in this area, all of which are judged to be reasonable.
- IGSCC of BWR Piping and Internals. This problem first affected BWR piping and then, in the last decade, has affected BWR reactor internals at an increasing rate. Remedies have been developed and applied for piping and have largely resolved the piping IGSCC problem. As discussed in Section 4.5, a large program (the BWR Vessel and Internals Project) is currently underway to address IGSCC of reactor internals, and many remedies have been developed and are in the course of being implemented, such as use of hydrogen water chemistry and noble metal chemical addition. No needed research in addition to that already underway was identified.
- Oxide Particle Erosion of Turbines. This problem results in large costs at fossil steam power plants. As discussed in Section 2.4, the erosion is the result of corrosion-produced particles that have spalled from superheater, reheater, and main/reheat steam tubes, headers and piping. This problem has been well understood for 20 years, and solutions such as chemical cleaning and chromizing of the particle source areas are available. Nevertheless, the relatively high costs shown in Table 6-1 imply that more work in this area is needed, perhaps mostly in the technology transfer area to help power plant operators better understand the causes and solutions to the problem. In addition, work on evaluating the effects of newer materials such as T91 seems to be warranted since they are experiencing unanticipated rates of oxide buildup.
- Boiler Tube Fireside Corrosion. Fireside corrosion of waterwall tubes in fossil steam boilers is a significant issue because it is aggravated by changes in boiler operating conditions caused by low NOx operation, and since requirements on NOx emissions continue to tighten. However, after plants are modified to resist fireside corrosion, generally by application of weld overlays in susceptible areas, fireside corrosion causes few boiler tube failures.

  There are significant environmental, regulatory, and economic pressures to use alternative fuels such as petroleum coke, tires, and biomass. The different impurities and combustion characteristics of these fuels are likely to raise new fireside corrosion problems. Because of the significant costs associated with fireside corrosion, and because of the incentives to use alternative fuels, it is considered that the R&D programs underway, as discussed in Section 2.6, should be continued and, if practical, expanded and accelerated.
- PWSCC of non-SG Alloy 600 Parts. Occurrence of PWSCC in Alloy 600 and related weld materials is an increasingly important problem in PWRs. As operating time accumulates, more and more parts are found to be affected, and the burden of inspection and repair of these materials increases. Continued research as described in Section 4.8 on developing improved inspection and remediation methods (e.g., use of zinc), and at resolving questions regarding the possible effect of low temperature crack propagation on observed PWSCC, and of what hydrogen levels minimize PWSCC at operating temperatures, is considered worthwhile.

- Corrosion of Concentric Neutrals. Corrosion of concentric neutrals in buried unjacketed distribution cables arose as a major issue several decades ago, and several EPRI reports on the problem were issued. Since that time, there has been no EPRI research on the problem. New residential cables are jacketed, and thus are not susceptible to corrosion of concentric neutrals. While there are many older unjacketed cables still in operation, and while corrosion of the concentric neutrals of these unjacketed cables continues to occur and results in substantial costs, utilities apparently have the needed technology to deal with the problem on a routine basis, e.g., monitor and replace as needed. No specific needs for further R&D on this topic were identified based on discussions with EPRI and utility personnel. However, based on the high costs involved, more detailed review of this problem may be warranted to determine if additional cost reduction methods are needed and practical.
- Copper Deposition in Turbines. Copper deposition in high pressure turbines can occur in fossil plants with pressures over about 2300 psi (15.9 MPa) and that have copper alloy feedwater heaters and/or condensers. The copper deposition can cause significant losses of efficiency and power output, and require periodic maintenance of the turbines. EPRI has issued guidelines for control of copper in fossil plants, and intends to update these in the coming years. The substantial costs incurred by this problem indicate that this effort is warranted.

## 6.2 Potential Future High Cost or Risk Items

There are a few corrosion problems that do not currently result in high costs but are judged as likely to increase in importance in the future, and are therefore summarized in this section.

- Combustion Turbines. Combustion turbines are likely to be used to produce an increasing fraction of the electricity used in this country, and will increasingly be used in a base load mode. The combustion turbines being used for these new installations are higher temperature machines. In the longer term, there are likely to be pressures for these new machines to use fuels in addition to natural gas, such as syngas or oil distillates. These factors – increased usage, higher temperatures, and alternate fuels – are likely to result in increased corrosion problems. For this reason, it is considered that R&D directed at minimizing corrosion problems in combustion turbines, especially new higher temperature units intended for base load operation, should be given high priority.
- HRSGs. Corrosion problems in the HRSGs of combined cycle plants have already become a significant problem, despite the young age of most combined cycle plants. Since combined cycle plants are the most common type of new generating facility being installed, since corrosion problems often worsen as equipment ages, and since the cost competitive nature of the industry leads to lack of attention to preventing long term problems, it is considered likely that corrosion problems with HRSGs will continue to worsen. Accordingly, it is considered that addressing the corporate culture and management issues related to minimizing corrosion problems in HRSGs is of high importance (as discussed in Section 3, the technical issues involved are already well understood).
- Fossil Plant Alternate Fuel Issues. There are environmental, regulatory, and economic pressures to use alternate fuels in fossil plants such as petroleum coke, tires and biomass. It is judged prudent for the industry to do the research needed to develop strategies for using these alternate fuels without incurring large fireside corrosion induced problems.

- Oil Pipelines and Tanks. Corrosion induced failure of oil transfer and storage equipment was identified by a power producer as having caused high costs at their plants, and as being a source of high risk to all plants with oil storage and transfer equipment. At the plants involved, the specific problems that had occurred were a failure of a buried oil supply pipeline, with large leakage of oil into a waterway, and two failures of oil burner supply hoses that caused expensive fires. Investigation of the problems indicated that there was little attention being paid by either power producers or regulatory bodies to possible corrosion induced failures of oil tanks, pipelines, and other oil transfer equipment. Investigation also indicated that failures of the equipment pose large risks, such as risks of wide scale environmental contamination of public waterways and water sources by leaks from large oil storage tanks or pipelines. It is considered that research into ways to monitor and control corrosion in oil storage and transfer equipment is warranted.

## 6.3 Need for Improved Technology Transfer

Several researchers noted that some serious corrosion problems are not being properly addressed because current knowledge is not being effectively applied. This situation was especially true for waterside/steamside corrosion issues in fossil plants and HRSGs. Most of the corrosion problems that affect the equipment in these sectors have been thoroughly studied, are well understood, and effective remedies have been identified. Nevertheless, the rate of corrosion problems has been increasing. It appears that the personnel managing operation of these facilities are not aware of the factors causing the problems, nor of the cost effective methods that are available to control these problems. Possible factors underlying this situation include high turnover of personnel and, most importantly, corporate cultures that do not set long reliability as a high corporate goal.

In response to this situation of worsening corrosion performance despite the availability of adequate technical knowledge in the fossil and combustion turbine sectors, EPRI has projects directed at developing and using technology transfer tools. These are intended to assist in changing corporate cultures to help them focus on long term corrosion prevention and reliability issues, and to train key personnel in how to cost effectively apply available technologies towards these ends. Considering the high costs incurred by the corrosion problems involved, continued and expanded emphasis on this type of technology transfer is judged to be highly worthwhile.

# 7
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EPRI creates science and technology solutions for the global energy and energy services industry. U.S. electric utilities established the Electric Power Research Institute in 1973 as a nonprofit research consortium for the benefit of utility members, their customers, and society. Now known simply as EPRI, the company provides a wide range of innovative products and services to more than 1000 energy-related organizations in 40 countries. EPRI's multidisciplinary team of scientists and engineers draws on a worldwide network of technical and business expertise to help solve today's toughest energy and environmental problems.

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