CORROSION AND WATER CHEMISTRY PROBLEMS IN STEAM SYSTEMS - ROOT CAUSES AND SOLUTIONS

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This paper summarizes problems and solutions identified during over 100 root cause analyses and plant audits of fossil fuel utility and industrial power plants, including combined cycle units. The audits are usually triggered by corrosion and scale/deposit buildup problems, but also by changes of plant management, high cost of water treatment chemicals, and by mistrust of the current water treatment contractor by the plant operators.

BACKGROUND

Prevention of corrosion and water chemistry related problems is best achieved through a combination of cycle design and material selection, commissioning of new units, operation, and maintenance. While our understanding has significantly improved during the last 20 years (1 to 21) and an estimated 90% of the needed knowledge is now available, application of this knowledge is still lacking, particularly in the industrial steam systems. This results in numerous problems and costly corrosion and scale induced efficiency losses (22).

The economic factors and competitive pressures triggered by the deregulation are now significant. The main cost factors are: the cost of replacement power and lost industrial production. These costs can be prevented, often at no expense to the steam cycle operators or at very high benefit to cost ratios. The best preventive measures include cycle and cycle component **design reviews** during the design phase, **commissioning** of water chemistry, and an **audit** of the water chemistry and corrosion control.

The **objectives** of the above measures are:

- Prevention/reduction of cycle component corrosion and the resulting forced outages and maintenance costs - a combination of mechanical and thermodynamic design, material selection, and operation.
- Operation at the maximum thermodynamic efficiency (minimum heat rate) and generating capacity - no excessive scale in heat exchangers and deposits in turbines.
- Optimization of water treatment and a reduction of the cost of chemicals

Achievable goals in the corrosion and water chemistry control are discussed in (1). They include elimination of all water chemistry related problems, operation at top efficiency, elimination of chemical cleaning, turbine inspection only every 10 years, and low cost of water treatment.

Audit Experience

Each of the over 100 analyses and audits performed resulted in one or more of the following achievements: improvement of communication between management, chemists, operators, and maintenance personnel, reduction of scale and deposit buildup, improvement of efficiency and generating capacity, reduction of corrosion, prevention of potentially catastrophic failures, faster startups, improvement of operation, better layup practices, improvement of sampling and instrumentation, better record keeping, improvement of the makeup and condensate polisher performance, and a reduction of cost of water treatment chemicals.

CORROSION AND WATER CHEMISTRY PROBLEMS

The following problems were frequently encountered during the analyses and audits of corrosion and water chemistry control in the fossil fuel utility and industrial cycles, including combined cycles. Table 1 lists the problems under various categories, gives the root causes and possible solutions and, in parentheses, gives an estimated % of units experiencing individual problems.

Table 1. Main Problems and their root causes and solutions

Problem and Root Cause (% of units experiencing the problem - estimated)	Solutions
MANAGEMENT	
Monitoring does not prevent major water chemistry upsets; it is not round-the-clock, there are no approved actions, training, etc. (80%)	Guidelines, training of operators and chemists, on-line instruments with alarms
Repeat failures - no root cause analysis - complacency (70%)	Multi-disciplinary root cause analysis, derived and verified solutions.
Delays, water chemistry upsets, and layup corrosion during testing and commissioning of new units (90%)	Commissioning guidelines, training, corrosion protection during storage and erection.
CYCLE DESIGN	
Mixed metallurgy makes good corrosion and water chemistry control difficult (40%)	All-ferrous systems (including auxiliary heat exchangers).
No means to effectively remove impurities from the cycle (70%)	Boiler blowdown design, blowdown of mud drums, filtration of return condensate and feedwater, condensate polishing, frequent chemical cleaning
High flow velocities in carbon steel piping leading to erosion-corrosion and cavitation (50%)	Proper design velocities or alloy steels, reduce oxygen scavenger, increase O_2.
OPERATION	
Operators controlling water chemistry underestimate the effects of upsets (60%)	Training, guidelines, management support.

Wrong or delayed corrective actions (60%)	Training, guidelines, management support.
Long startups due to high concentration of oxides (30%)	Proper layup, filling with deaerated water.
BOILER, SUPERHEATER, AND REHEATER	
High carry-over due to damaged internals, drum level control, foaming, high solids (25%)	Inspect and fix, improve chemistry, monitor Na and cation conductivity in steam, train operators.
Boiler tube failures due to high local heat flux and poor circulation (20%)	Adjust combustion, reduce maximum load, clean boiler, do not patch weld.
High water quality because of high approach temperature leading to erosion-corrosion (15%)	Balance the heat input in the economizer.
Exfoliation of magnetite leading to solid particle erosion of turbine blades and >Fe throughout the cycle, long startups (80% of other utility units)	Chemical cleaning of superheater and reheater, balancing the fireside temperatures
TURBINE	
Blade and disk corrosion (pitting, corrosion fatigue, and stress corrosion) in the LP section due to marginal steam chemistry, no layup, high stresses and vibration (40%)	Control steam chemistry and layup, tune blade vibration, redesign blade attachment.
HP turbine deposits leading to loss of performance in high pressure drum boiler units due to carry-over of copper and phosphate (80%)	Optimize cycle chemistry, replace copper alloy tubing in HP heaters.
Sticking turbine valves due to impurities in steam (several cases of destructive overspeed) (20%)	Exercise valves weekly, improve steam purity.
CONDENSER	
Condenser tube leaks due to a variety of reasons (pitting, erosion, ...) (60%)	Preventive tube plugging, replace with better material.
DEAERATOR	
Corrosion cracking of welds - root cause not known, possibly water piston and high residual stresses (40%)	Calculate and change the conditions for water piston, inspect periodically and perform fracture mechanics evaluation.
High oxygen in effluent due to distress of the internals (20%)	Fix internals, better control of pressure, temperature, and load changes.

FEEDWATER HEATERS AND HEAT EXCHANGERS	
Erosion-corrosion of tube inlets due to high local flow velocities and turbulence (50%)	Tube inlet inserts, replace tubes with more resistant material.
Pitting and leaks in austenitic stainless steel tubing due to the presence of chloride in feedwater (30%)	Improve feedwater chemistry. When replacing tubes, use better material, test for large inclusions.
PIPING	
Erosion-corrosion of feedwater piping due to high flow velocity, turbulence, low pH, and excessive concentration of oxygen scavenger (70%)	Inspect critical components ASAP, evaluate feedwater and wet steam piping, improve water chemistry.
WATER CHEMISTRY	
Inadequate sampling points (i.e. steam, return condensate) (40%)	Improve sampling
Sampling errors due to low sample flow, high sample temperature, long sample lines, surface taps, deposits in tubing (70%)	Increase sample flow to 6 ft/sec, clean coolers, satellite sampling with shorter lines, isokinetic sampling nozzles
Bad organic chemicals or their overfeeding leading to high concentration of organic acids, corrosion, and scale and deposits (60% of industrial)	Evaluate the use of chemicals, minimize concentration, neutralize acidic conditions.
Air inleakage (oxygen and CO_2) (80%)	Identify locations using helium or SF_6, fix leaks.
Analytical interferences of some organic chemicals with analysis of O_2, SiO_2, etc. (30% of industrial)	Determine interferences, change analytical method
Boiler tube failures: caustic gouging, hydrogen damage, pitting, and overheat due to high levels of impurities in boiler water	Control condenser leaks, improve corrective actions, reduce feedwater Fe, chemically clean boiler, change water treatment
Contaminated return condensate (Fe, Cu, organics, process chemicals) (40%)	Monitor, polish, automatic dump
Release of makeup or condensate polisher regenerants due to unreliable or poorly designed valving and inadequate monitoring (5%)	Reliable design, maintenance, monitoring, proper operator actions

DISCUSSION

All problems listed in Table 1 are ultimately related to the management throughout the design, commissioning, and operation of the steam cycle. A design review of the cycle and its individual components, training of operators, commissioning, and guidelines for all modes of operation and layup can eliminate most water chemistry and corrosion problems. This has been demonstrated by good utility and industrial companies and in the countries such as Germany where there are **very few problems** (7).

The **cost of corrosion, and scale and deposit buildup** in the U.S. utility systems is over $3 billion/year. It is even higher for the industrial steam systems. As much as 50% of the outage time has been attributed to corrosion, with the boiler tubes, condensers, turbines, feedwater heaters, carbon steel piping, PWR steam generators, and BWR pipe welds being the main contributors. The cost of replacement power can be as high as $100/MWh or over one million dollars a day for a large utility unit ($7000/MWh - summer 1998). The cost of reduced or lost production in an industrial plant can be equally high.

The **benefit to cost ratios** for most solutions to the problems listed in Table 1 are very favorable (over 1000). In many cases, the cost of a problem solution is zero (i.e. operation without condenser leaks, proper operator actions in cases of upsets, no patch welding when repairing boiler tube leaks). Table 2 gives examples of the cost of replacement and repair for selected components.

Table 2. Typical cost of replacement and repair (parts and labor) and outage length

Component	Cost of Replacement ($ million)	Length of Outage (weeks)
PWR Steam Generators	150 - 200	26 - 52
BWR Piping	70	52
Fossil Boiler Water Walls	5 - 12	20 - 32
Fixing Boiler Tube Leak	0.1 - 0.5	2 days
Secondary Superheater & Reheater (high temp. part)	5 - 8	12 - 26
Turbine Rotors (bladed)	5 - 20 (50)	6 - 12
Row of Blades	0.1 - 0.8	3 -8
Condenser Retubing	3 - 18	8 - 26
Feedwater Heater Retubing (one)	0.6 - 1.2	2 - 6

Safety Issues - There are several water chemistry and design related safety issues, sometimes resulting in fatalities. They include, in order of priority, erosion-corrosion of feedwater and wet steam piping (17, 18), deaerator and blowdown flash tank stress corrosion and corrosion fatigue cracking at welds (19), stress corrosion and burst of turbine rotors and disks (15, 16), and overspeed turbine rotor failures due to deposits and malfunction of turbine valves. There are other, less frequent, safety issues.

Current generic problems include: Erosion-corrosion of carbon steel piping and other components, boiler tube failures, deaerator weld cracking, pitting, corrosion fatigue, and stress corrosion cracking of LP turbine blades and blade attachments, copper deposition on HP turbine blades and loss of MW, solid particle erosion, and numerous corrosion problems in nuclear units.

CONCLUSIONS AND RECOMMENDATIONS

1. Over 100 problem root cause analyses and corrosion and water chemistry audits were performed of industrial and fossil utility units, the age of which ranged from 30 days to 40 years. Most of these units had management and technical problems and the primary objective of the audit was to resolve them. The secondary objectives included reduction of forced outages, reduction of the cost of water treatment, assurance of the design life, and prevention of equipment failures.

2. In all the audits, short- and long-term improvements were recommended and after most of the audits, short-term improvements were implemented.

3. The audits are useful just after commissioning of new units, repeated after about every 5 years, when there are reported troubles (corrosion, scale, and deposits), for all units older than 10 years (even when there are no obvious troubles), for all combined cycle units, for all units with mixed metallurgy (Fe + Cu), and for all units using organic water treatment chemicals.

4. The main problems encountered include a lack of monitoring and approved operator/chemist actions which can prevent major upsets, poor communication between management, chemists, operators, and maintenance, corrosion in boilers, turbines, feedwater heaters, condensers, deaerators, and piping, scale and deposit buildup, reduction of efficiency and generating capacity, long startups, lack of layup protection, inadequate sampling and instrumentation, lack of training of operators and chemists, insufficient or no root cause analyses, bad makeup and condensate polisher performance, use of bad chemicals, and high cost of water treatment chemicals.

5. The safety issues encountered during the audits include: erosion-corrosion (flow-accelerated corrosion) of carbon steel piping, boiler drum components, and elsewhere, cavitation in feedwater system, corrosion cracking of carbon steel welds in deaerators, other vessels, and piping, stress corrosion cracking in LP turbines, and sticking turbine valves.

6. The potential identified cost savings included water treatment chemicals (both the type of chemicals and quantity), elimination of equipment replacement or extension of the time

periods for replacement (mostly in industrial units), extension of the chemical boiler cleaning interval, extension of inspection and repair interval (deaerators, boilers, turbines), and shorter startups. The savings were from $50,00 to several million dollars annually.

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