Steam Turbine Problems and Their Field Monitoring

OTAKAR JONAS AND JOYCE M. MANCINI, *Jonas, Inc.*

This article describes typical turbine corrosion problems and the monitoring techniques used to predict, prevent, and troubleshoot them. The effects of corrosion on turbine efficiency are covered. Several testing procedures are discussed. The costs of the loss of turbine efficiency and lost production vs the cost of repairs are noted.

In steam turbines and other steam-handling equipment, it is imperative to identify corrosive conditions, corrosive characteristics of materials, exfoliated oxides causing solid particle erosion, and deposit buildup. Available monitoring instruments and methods include the following:

- Steam turbine deposit collector/simulator.
- Converging-diverging nozzle for low-pressure (LP) turbines.
- Converging nozzle for high-pressure (HP) turbines.
- Drying probe for wet steam stages.
- Boiler carry-over monitors.
- Early condensate samplers.
- Particle flow monitors for exfoliated oxides, steam blow, and water droplets.
- Water induction monitors.
- Corrosimeter for erosion-corrosion monitoring.
- U-bend specimens installed inside turbines to determine susceptibility of different materials to pitting and stress corrosion.
- Fracture mechanics specimens to determine stress corrosion, corrosion fatigue crack growth rate, and crack incubation times.

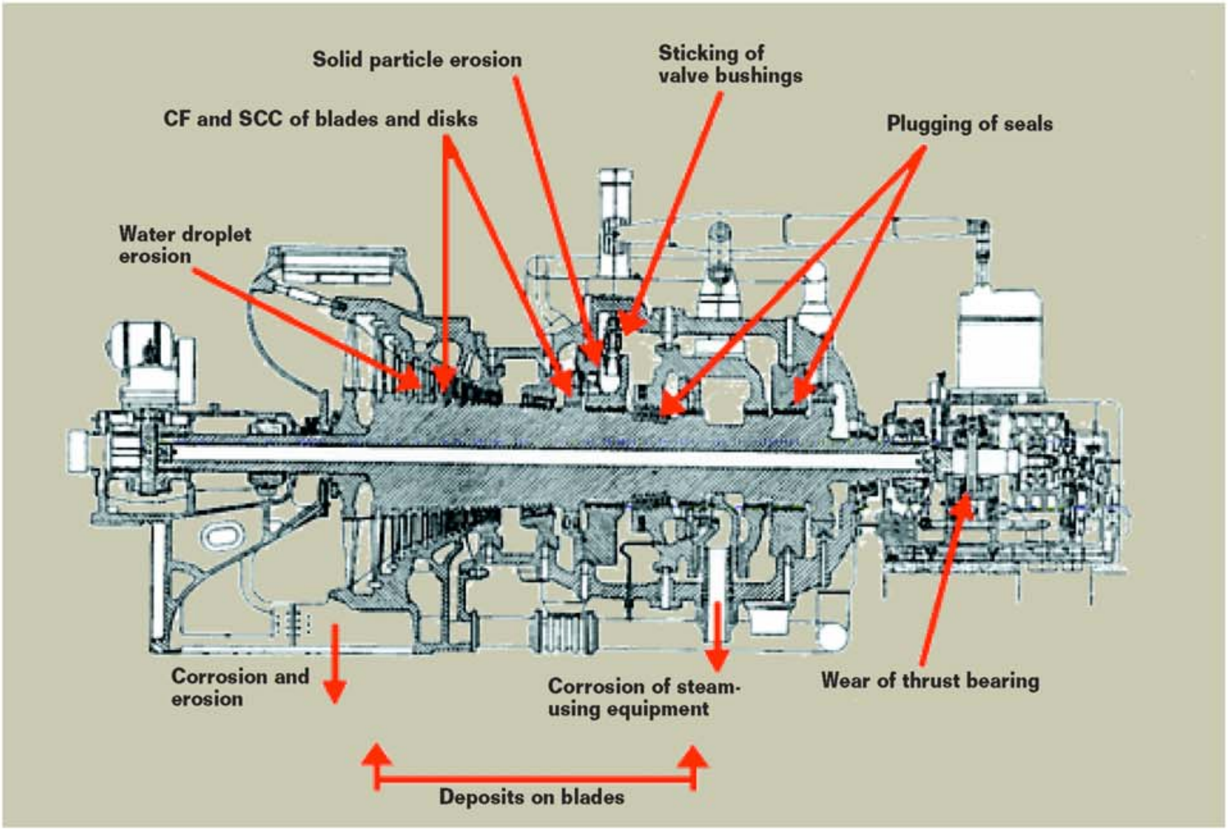
Turbine Problems

Typical turbine problems[1-10] include pitting corrosion, corrosion fatigue (CF), stress corrosion cracking (SCC), deposit buildup, solid particle erosion, and water droplet erosion of the wet stages. Turbine component failures and loss of efficiency and generating capacity resulting from deposition are very costly. The cost of lost production is ~10 times higher than the cost of repairs. Figure 1 shows typical turbine problem locations.

Experiments and field experience have shown that up to 15% of megawatt (MW) generating capacity loss can be caused by erosion and buildup of blade deposits. In addition, solid particle erosion that is caused by exfoliation leads to expensive maintenance and blade replacement in addition to lost output.

There are thousands of steam cycles worldwide where turbine performance has been impaired by blade surface finish deterioration and/or buildup of turbine deposits. These problems and opportunities for improvement have been recognized for >50 years, but today's competitive business environment is only now providing strong incentives for improvement. With replacement power typically at >\$100 per MWh and costing as much as \$7,000 per MWh, the savings can be very significant. For a unit with a Cu deposition problem resulting in a 30-MW loss of capacity and a difference between the sale price and the cost of generation of \$30 per MWh, the yearly loss is >\$5 million.

FIGURE 1



Typical turbine with locations of deposition, corrosion, and related problems.

The current trends of increasing turbine inspection and cleaning intervals to 10 years and extending the warranty period to up to 20 years requires the best achievable control of turbine deposits, erosion, and corrosion. The root causes of these problems include:

- **Operation with a high concentration of impurities in turbine steam.** It is estimated that ~40% of U.S. utility and 60% of industrial turbines operate with high concentrations of impurities in steam.
- **Marginal design of blades and disks** (i.e., high steady and vibratory stresses, not considering impurity concentration and all appropriate corrosion properties, and improper materials).
- **Poor, improper, or inadequate monitoring of steam chemistry.** Na and cation conductivity should at least be monitored and should be the routine way to prevent deposition of salts and hydroxides, which can lead to corrosion, loss of efficiency, and MW generation.[11-12] For troubleshooting and commissioning, additional parameters should be monitored.

Deposit Buildup

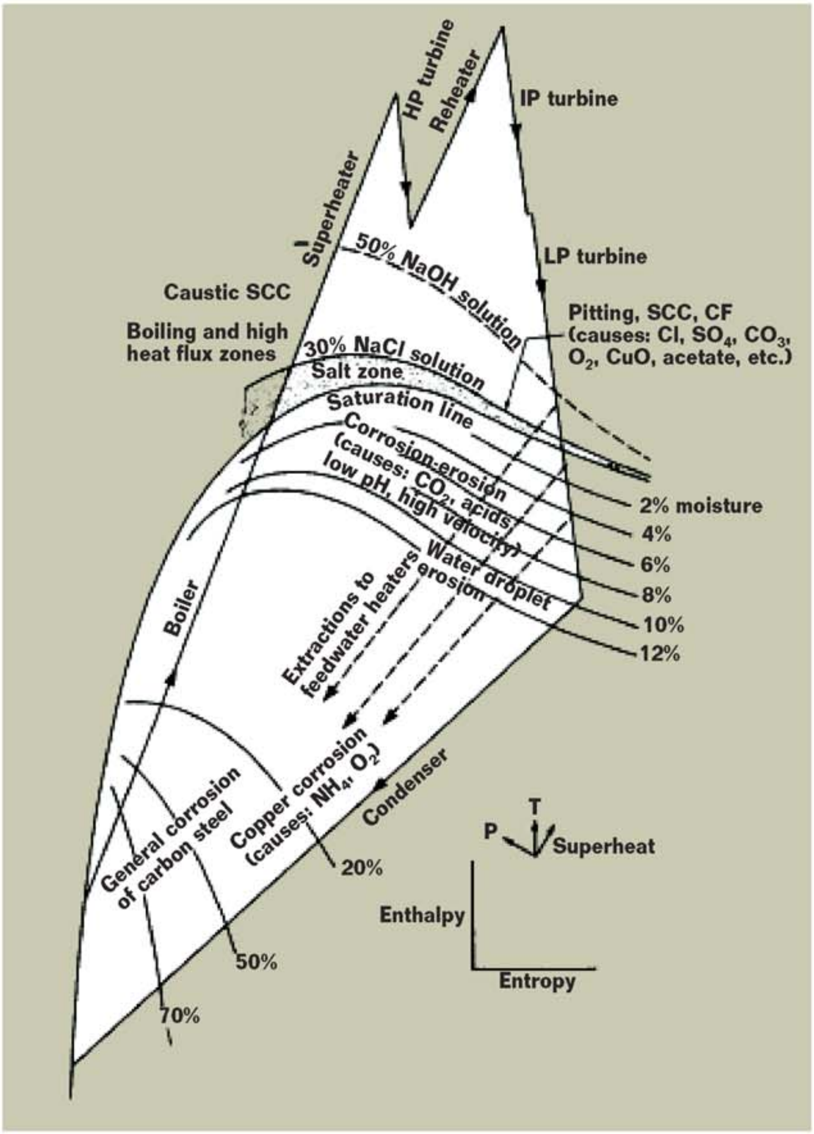
The impact of deposits on turbine performance depends on their thickness, their location (steam pressure), and the resulting surface roughness. Deposits will change the basic profile of the nozzle partitions resulting in losses caused by changes in energy distribution and aerodynamic profiles as well as surface roughness effects. These changes can result in large MW and efficiency losses in addition to the cost of extra fuel, emissions, turbine washing, boiler chemical cleaning, and maintenance. The processes by which deposits are formed are:

- Precipitation from superheated steam and deposition of mineral particles and acid droplets.
- Evaporation of moisture (liquid films) on surfaces above saturation temperature and retention of the mineral residue.
- Deposition of metal oxides formed elsewhere in the steam cycle (mechanical boiler carry-over, exfoliation in superheater and reheater, etc.).
- Adsorption of gases and dissolved impurities in superheated and wet steam on oxidized surfaces.

Corrosive Environments

The steam turbine environment consists of 1) superheated and wet

FIGURE 2



Mollier diagram for a drum boiler cycle with regions of impurity concentration and corrosion.

steam with low levels (ppb) of dissolved and suspended impurities, 2) deposits that have formed by precipitation and plating-out in the superheated steam sections and by drying of moisture on hot surfaces, and 3) moisture film and droplets containing concentrated low-volatility chemicals.

Each of these chemical environments has a different effect on turbine materials and performance. In addition to the reactive chemicals (salts, acids, and hydroxides), which can cause various forms of corrosion, solid impurities—predominantly magnetite exfoliated from superheaters, reheaters, and steam pipes—can cause solid particle erosion and chemically interact with the reactive chemicals.

Turbine corrosion and impurity behavior zones are shown, together with turbine steam expansion lines, in the Mollier diagram in Figure 2. Figure 3 summarizes the current understanding of the physical-chemical processes occurring in LP turbines. In the superheated region, impurities dissolved in steam may precipitate and deposit because their solubility in steam decreases as the steam expands. In the "salt zone," salts and acids can be present as highly concentrated corrosive solutions. Sodium hydroxide (NaOH) can be thermodynamically stable as a concentrated solution anywhere in the superheated steam region. In the wet steam region, impurities distribute between the gas and moisture which, at low pH and high velocity, can cause erosion-corrosion. Some surfaces surrounded by wet steam can be heated by heat transfer or flow stagnation resulting in evaporation of moisture and concentration of impurities on the surface.

New Monitoring Devices

Field-monitoring equipment can be used to diagnose and prevent many common problems.[13] Table 1 summarizes the devices available. Figure 4 shows the installation locations for equipment used in LP turbines. There are also monitors available to detect vibration, blade and rotor cracking, steam leaks, air inleakage, rotor position, and bearing wear.

DEPOSITS

Several diagnostic tools can determine deposition rates, deposit composition, and morphology in turbines. They include:

- **Steam turbine deposit collector/simulator.** This filter-like device simulates the turbine conditions governing deposition from superheated steam and can be installed anywhere in piping or in a turbine.
- **Converging-diverging nozzle for LP turbines.** Simulates steam expansion along the blade path in fossil and nuclear LP turbines to determine the amounts and types of impurities that are depositing on turbine blades.

TABLE 1

SUMMARY OF DEVICES AVAILABLE FOR DEPOSIT, CORROSION, AND EROSION MONITORING

Device	Application	Monitoring Results
Steam turbine deposit collector/simulator	Simple troubleshooting tool for collection and analysis of HP, IP, and LP turbine deposits without turbine disassembly	Deposit composition, morphology, and rate of deposition vs operation
Converging-diverging nozzle for LP turbines	Simulates steam expansion in fossil and nuclear LP turbines along the blade path	Types of impurities depositing on LP turbine blades and corrosiveness of the environment
Converging nozzle for HP turbines	Simulates fossil HP turbine deposition; Cu deposits, MW loss, solid particle erosion	Types of impurities depositing on HP turbine blades
Drying probe for wet steam stages	Simulates moisture drying on hot surfaces in LP turbines; related to pitting, SCC, and CF	Deposits of low-volatility impurities in LP turbines are collected
Boiler carry-over monitors	Direct monitoring of % moisture	Mechanical carry-over
Early condensate samplers	Corrosion and flow-accelerated corrosion (erosion-corrosion) in LP turbines	Chemistry of water droplets formed in the final stages of the LP turbine
Particle flow monitor for exfoliated oxides, steam blow, and water droplets	Solid particle and water droplet erosion; also used to monitor effectiveness of steam blow	Number and size distribution of oxide particles in superheated and reheated steam and water droplets in wet steam stages
Water induction monitors	Liquid water in steam pipes	Alarms, % of liquid water in steam pipes
Corrosimeter for erosion-corrosion (flow-accelerated corrosion) monitoring	Erosion-corrosion vs water chemistry and operation—pipe wall thinning	Thinning rate for materials of concern in the suspected areas of piping
U-bend specimens	Corrosion, SCC	Detect general corrosion, pitting, and SCC conditions
Fracture mechanics specimens	SCC and CF	Stress corrosion crack growth rate and crack incubation times

- **Converging nozzle for HP turbines.** Simulates steam expansion in the fossil HP turbine control stages to determine the amounts and types of impurities depositing on turbine blades.

The deposits that are collected with each of these devices can be analyzed using optical and scanning electron microscopy, energy dispersive x-ray spectroscopy, x-ray diffraction, and wet chemistry methods. Deposit analysis results can be used to predict deposition and corrosion inside the turbine, and to assess boiler carry-over and the effects of steam and water chemistry upsets.

WET STEAM ENVIRONMENTS

Several instruments can gauge the corrosiveness of the wet steam environment. Some of these include:

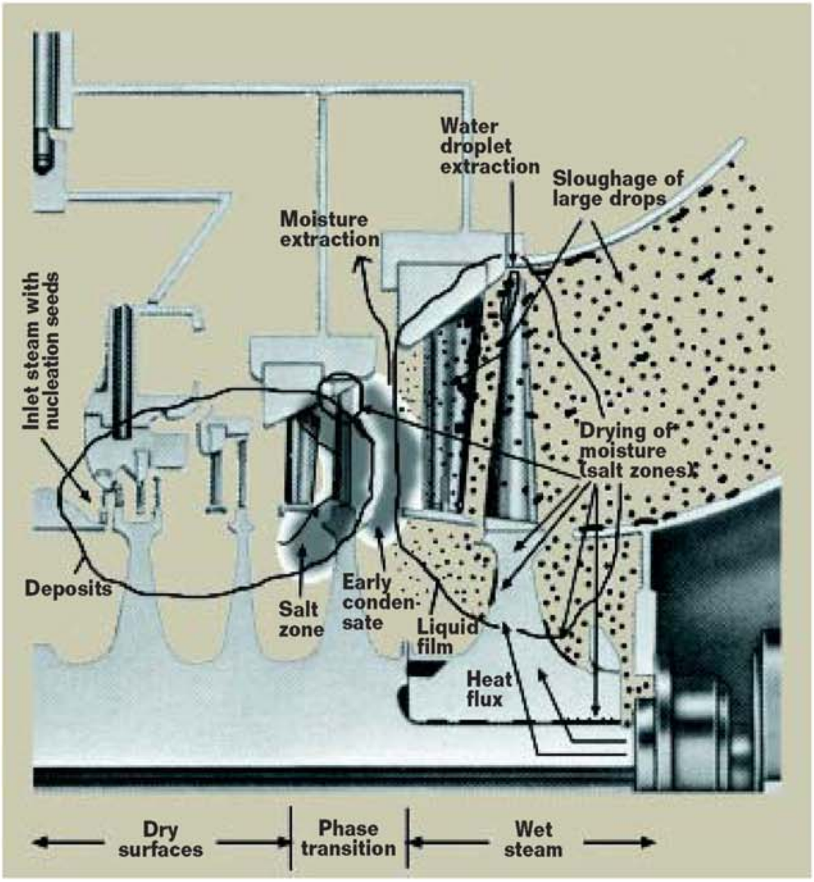
- **Drying probe for wet steam stages.** This simulates the evaporation of moisture and the concentration of low-volatility impurities on hot surfaces. The droplets carrying dissolved impurities impact the probe, evaporate, and leave behind the impurities as deposits on the probe surface. Deposit analysis can determine the corrosiveness of the environment.
- **Boiler carry-over monitors.** Two new monitors have been developed that can measure high boiler carry-over and the percentage of moisture in process and heating steam and the steam used for oil recovery. One monitor is based on the absorption of gamma radiation and the second on online calorimetry combined with isokinetic sampling.
- **Early condensate samplers.** These are used to collect samples of steam moisture in turbines. The condensate is collected and withdrawn for analysis while saturated steam is vented into the turbine space. Two types of samplers are available: internal and external.

EXFOLIATION AND SOLID PARTICLE EROSION

Solid particle erosion in steam turbines is typically caused by exfoliated oxides from the superheater, reheater, and steam piping. The primary effects of solid particle erosion include decreased unit efficiency, increased maintenance costs for steam path inspections and repair/replacement costs, lengthened outages, more frequent inspections for ensuring the mechanical integrity of components, and increased probability of forced outages resulting from a failure of an eroded steam path component.

- **Particle flow monitor for exfoliated oxides and water droplets.** This determines the number

FIGURE 3



Cross section of an LP turbine with the locations of the physical-chemical processes. Note: This diagram illustrates regions where impurities will concentrate and promote corrosion. Points in the diagram should relate to actual conditions at component surfaces, not to the theoretical average flow path conditions. Heat transfer, surface cleanliness, crevices, and surface-flow stagnation conditions determine the actual surface temperatures and pressures.

and size distributions of oxide particles or water droplets in steam. The monitor probe is inserted into the pipeline and a computer records each particle or droplet as it impacts the probe. The number of particles/droplets, average mass of particles/droplets, and the mass of each individual particle/droplet can all be measured. In addition, the particle/droplet size can be calculated. Data obtained from this monitoring are used to pinpoint the operating conditions when erosion is highest and to indicate when chemical cleaning of the superheater or reheater may be necessary.

• **Water induction monitors.** Water induction and accumulation in steam piping and water reentrainment into the turbine can lead to water hammer and other damage. Three types of instruments can detect this condition quickly: gamma gauge, water droplet monitor, and fast response thermocouples.

CORROSION AND EROSION

The corrosimeter for erosion-corrosion monitoring can be installed in wet steam piping and inside turbines. It continuously monitors the thinning rate and the effects of operation and steam chemistry. Several types of this instrument are commercially available that are based on the measurement of electrical resistance of a wire loop exposed to the flow and environment.

U-bend corrosion specimens, placed near the saturation line, give a good indication of turbine corrosion. They can detect general corrosion, pitting, and SCC conditions. Under constant environmental conditions, pitting of turbine materials is proportional to the cube root of time.

Depending on stress, CF and stress corrosion cracks propagate from the pits, leading to blade and other component failures. Utility turbine blades can typically crack from pits ~10 mils (25 µm) deep; but, cracking from pits as small as 3 mils (76 µm) has been observed—mostly in LP L-1 blades. Figure 5 portrays an exposed U-bend.

Fracture mechanics specimens such as 1T-WOL wedge-loaded specimens have been used to determine stress corrosion crack growth rate and crack incubation times. Hydraulically loaded specimens in autoclaves using turbine steam have been used to determine CF characteristics of materials in turbine environments.

Conclusions

These diagnostic devices have all been tested and used to troubleshoot steam systems and have performed as expected.

These devices are providing new information on the transport and behavior of steam impurities, including:

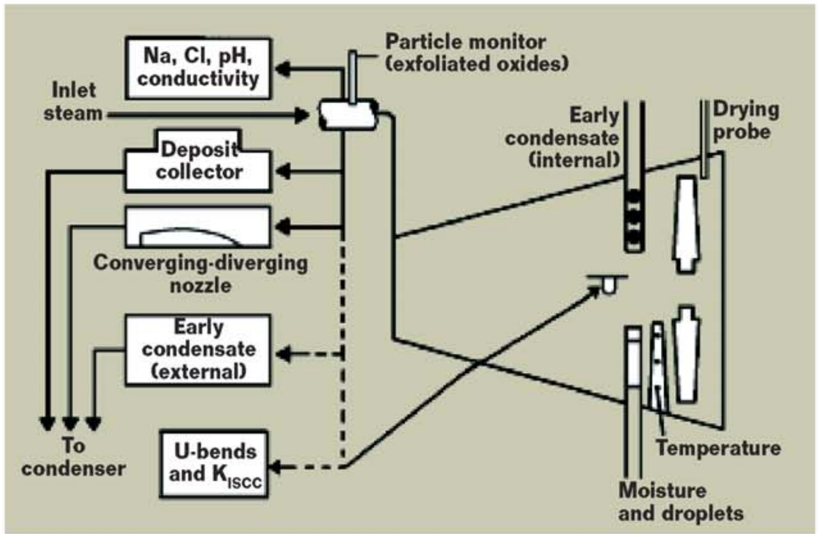
- Relationships between bulk steam chemistry and deposition.
- The rate of deposition and form of precipitates of steam impurities in LP turbines.
- The rate of deposition and form of Cu in HP turbines.
- Transport, concentration, and size distribution of exfoliated oxides.
- Hideout and release of contaminants from superheaters and reheaters.

• Distribution of moisture film on LP turbine blades.
• Composition of early condensate.
• Drying of moisture on hot surfaces.
• Interaction of oxides with other impurities.
• Number, size distribution, and chemical composition of potential nucleation seeds.

In troubleshooting, the following turbine problems have been investigated with these devices:

• Corrosion in the phase transition zone of LP turbines.
• Excessive deposits leading to loss of capacity and efficiency and corrosion.
• Hideout of corrodents in superheater and reheater after contamination of a boiler by seawater.
• Erosion-corrosion in two-phase region.
• Exfoliation and solid particle erosion.
• Effectiveness of chemical cleaning of superheaters and reheaters.
• Effectiveness and monitoring of steam blow.

FIGURE 4



Installation locations of equipment available for LP turbines.

FIGURE 5

Carbon steel U-bend showing general corrosion, pits, and flaky deposits on the outside surface.

References

1. O. Jonas, MP 24, 2 (1985).
2. EPRI CS-2932, "Characterization of Operational Environment for Steam Turbine-Blading Alloys" (Palo Alto, CA: EPRI, 1982).
3. A. Whitehead, G.F. Wolfe, "Steam Purity for Industrial Turbines," 8th ASME Industrial Power Conference (Houston, TX: ASME, 1980).
4. EPRI TR-108184, "Steam, Chemistry, and Corrosion in the Phase Transition Zone of Steam Turbines" (Palo Alto, CA: EPRI, 1999).
5. T. McCloskey, B. Dooley, W. McNaughton, "Turbine Steam Path Damage: Theory and Practice" (Palo Alto, CA: EPRI, 1999).
6. O. Jonas, B. Dooley, "Steam Chemistry and Its Effects on Turbine Deposits and Corrosion," Proceedings of 57th International Water Conference (1996).
7. O. Jonas, et al., "Copper Deposition and MW Loss: Problem and Its Solutions," Proceedings of 57th International Water Conference (1996).
8. O. Jonas, "Erosion-Corrosion of PWR Feedwater Piping—Survey of Experience, Design, Water Chemistry, and Materials," Report for U.S. Nuclear Regulatory Commission, NUREG/CR-5149, ANL-88-23 (1988).
9. EPRI CS-4683, "New Continuous In-Line Method for Monitoring of Solid Particles and Results of Field Testing," O. Jonas, Proceedings of Solid-Particle Erosion of Utility Steam Turbines: 1985 Workshop (Palo Alto, CA: EPRI, 1986).
10. K.C. Cotton, "Evaluating and Improving Steam Turbine Performance" (Rexford, NY: Cotton Fact, Inc., 1993).
11. EPRI CS-4629, "Interim Consensus Guidelines on Fossil Plant Cycle Chemistry" and other EPRI guidelines (Palo Alto, CA: EPRI, 1986).
12. O. Jonas, "Diagnostic Monitoring—An Overview," Power, January 1992.
13. O. Jonas, "On-line Diagnosis of Turbine Deposits and First Condensate," Proceedings of 55th International Water Conference (1994).

OTAKAR JONAS is a consultant with Jonas, Inc., 1113 Faun Road, Wilmington, DE 19803. He has more than 30 years of experience in troubleshooting and research and development of corrosion prevention, and water chemistry in utility and industrial steam generation. He is a professional engineer and has a Ph.D. He has been a NACE member since 1978 and is a member of the *MP* Editorial Advisory Board.

JOYCE M. MANCINI is an engineer with Jonas, Inc. She designs sampling equipment and systems, analyzes deposits and scale, and uses monitoring methods described in this article. She has a B.S. in chemical engineering and is a 1-year NACE member. MP