

Coatings in Power Plants:

Controlling Fouling and Corrosion in Tubing

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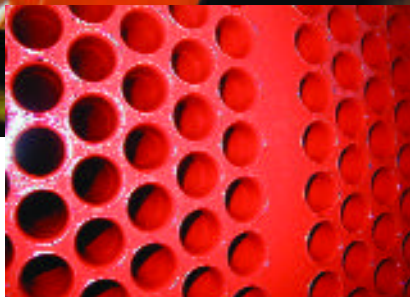
Most power plant owners understand the importance of heat transfer—the ability of a cooling system to extract heat from a medium—but disregard the problem of poor heat transfer because it is considered an “efficiency factor.” Heat transfer inefficiency normally does not affect unit availability or reliability, so it is disregarded despite loss of plant efficiency and reduction of total megawatt (MW) output. This is a mistake. Working on inefficient heat transfer can solve many “real” problems. Maintenance costs can be reduced and the life of equipment extended by addressing fouling and heat transfer issues. Plant efficiency can be increased and a unit’s MW output increased. Coating of heat exchanger (HX) and condenser tubes may resolve both fouling and corrosion problems without losing heat transfer capabilities, providing greater efficiencies, reducing cleaning maintenance costs, and extending the life of capital equipment.

Background

Facility owners face many problems with heat transfer in today’s restrictive and regulated discharge environment. Restrictions on chemical use for once-through cooling water systems are tougher than ever.

Most plant cooling water discharge permits will not tolerate the discharge of any chlorine or metals or let total dissolved solids (TDS) exceed stringent low-level limits. Such restrictions prohibit common past practices of adding chemicals to cooling water systems to control fouling, deposits, and corrosion.

Facility water-cooled heat exchangers, large AC units, and condensers are all affected. They corrode faster and need maintenance cleaning more often than many other types of units in power plants. Thus, the reliability, availability, and performance of this equipment become an issue. For power plants, heat rates are greatly affected, limiting plant outputs in mega-watts (MW). At the same time, emissions increase because



additional fuel is burned.

The cycle is degenerative, and as tube deposits build up and system temperatures increase, corrosion rates increase as well. There is decidedly more under-deposit tube corrosion, and passive films become active, leading to leaks.

The choices here seem limited. You can increase the frequency of maintenance cycles to a certain extent, but this adds to both operation and maintenance (O&M) costs and reduces equipment availability. You could add redundant equipment to increase availability, but this again adds to bottom line costs. Most owners are faced with the cost of replacing or re-tubing because equipment doesn't last as long as in the past. Again, O&M costs increase.

Corrosion, Deposition, and Fouling

A cooling water system, whether a pond, river, closed cycle recirculation towers, or ocean, contains many metals and fouling types. Their interactions are almost all unique to the specific process and conditions, as shown in the many publications that discuss cooling water chemistry, deposits, and corrosion failures.^{1, 2, 3, 4, 5, 6, 7}

The interactions of various cooling waters with the materials of construction of cooling water systems have given rise

to the large numbers of water chemists and cleaning services contractors that thrive in our industries. Heat exchanger fouling is a major economic problem, and maintenance costs are estimated to account for 0.25% of the world GDP.⁷

Fouling typically falls into the following discrete categories.

- Micro and macro biological fouling— aerobic and non-aerobic—bio-fouling
- Particulate—silt, mud, and sand— insoluble products, suspended solids, sediment or silt accumulation
- Crystalline—salt deposition (Ca Carbonates and Sulfates, others)—dissolved salt deposition (organic/inorganic) or crystalline-ionic fouling
- Corrosion—metals are oxidized, metal fluid reactions
- Chemical reaction—petroleum refining and polymer production interactions (These include organic fouling such as asphaltenes, coking, and polymerization reactions not covered in this paper.)

Equipment is usually subject to more than one type of fouling. The mechanisms are interactive and inter-related. For example, macro fouling cuts down on cooling water flow and thus allows more sedimentary deposits, which in turn can lead to micro-fouling and corrosion. Fouling rates are affected by both temperature and cooling water

flow rate.

Figure 1 shows the effects of surface temperature on relative fouling when the flow is constant. Four effects are summarized below.

- Crystalline fouling greatly increases with temperature.⁷
- Biological fouling decreases with temperatures above 50 C and has little to no effect at temperatures above 140 C.⁷
- Particulate fouling increases slightly with temperature but is almost constant.⁷
- Corrosion fouling decreases slightly above 50 C.⁷

Figure 2 shows the effects of flow on relative fouling when the temperature is constant. Four effects are summarized below.

- Biological fouling decreases with flow over 0.7 m/s and stops over 2.2 m/s.⁷
- Crystalline fouling slightly decreases with flow over 0.5 m/s.⁷
- Particulate fouling decreases with flow and stops above 1.7 m/s.⁷
- Corrosion fouling decreases very slightly with flows above 1.2 m/s.⁷

The extent of fouling can be determined in a variety of ways, including looking in the HX and tubes, and calculating pressure drops, temperature rises, turbine backpressures, or other unit efficiency measurements. The most com-

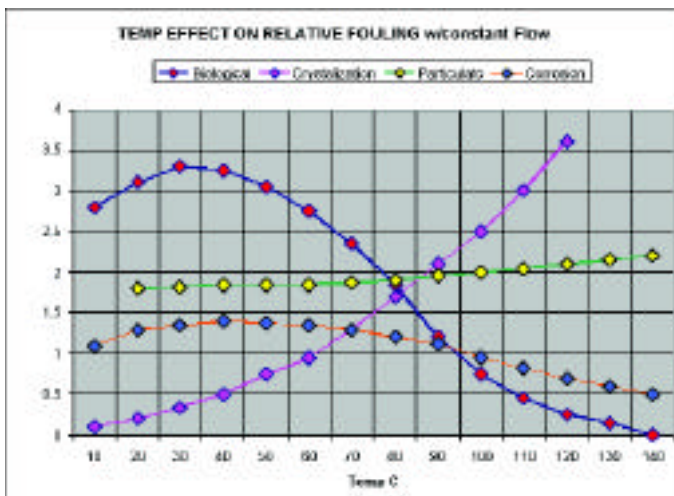


Fig. 1: Relative seawater fouling with temperature at constant flow

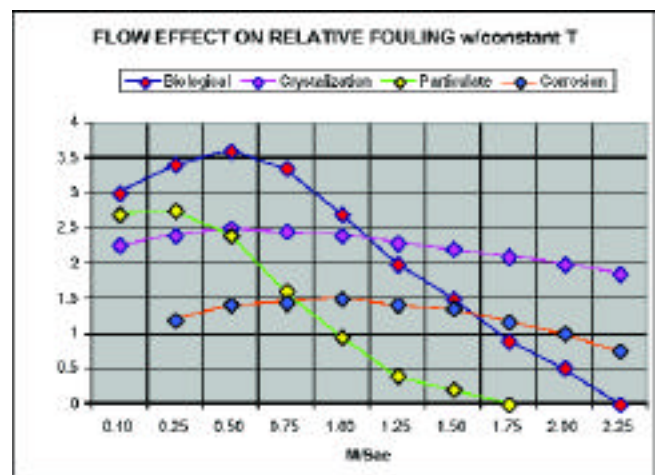


Fig. 2: Relative seawater fouling with flow at a constant temperature

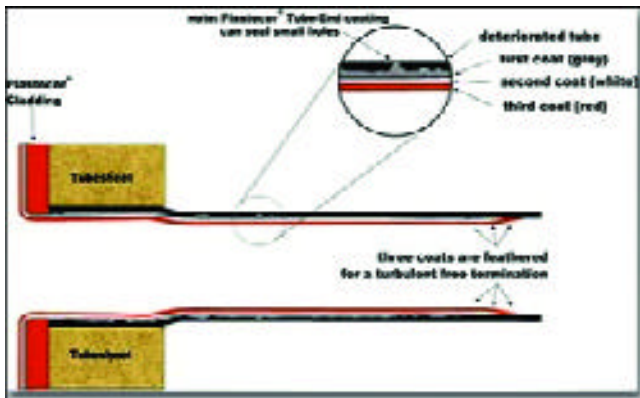


Fig. 3A: Inlet coating of tubes

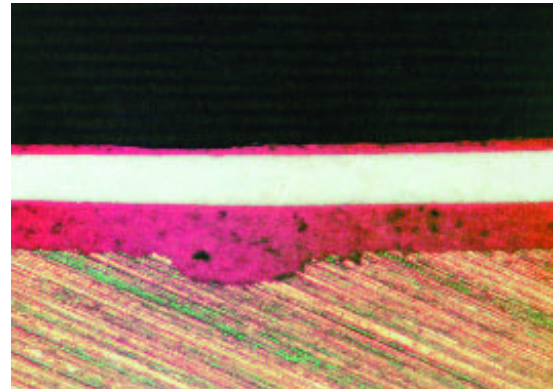


Fig. 3B: Magnified view

mon method is simply cleaning when plant operations are affected. This method is not enough to minimize the cost of fuel or electricity or loss of equipment life due to tube corrosion.

Performance modeling is necessary to determine optimum times for cleaning and efficiency maintenance. Heat Exchanger Institute (HEI) standards (Cleanliness Factor—CF), EPRI standards (Taborek & Tsou Performance Factor—PF), or Engineering Sciences Data Unit (ESDU) guide data⁸ can be used, or you can develop your own performance models, which most companies choose to do. The simplest way to develop a model is to compare heat transfer just before and just after cleaning, then calculate the increase in efficiency due to the heat transfer gained.

For example, if a 500MW condenser is not cleaned, the cost of fouling can amount to over \$265,000 in one year. One cleaning will pay for itself seven fold in direct fuel costs. This example includes only the direct losses of fouling, not the costs of corrosion of materials due to fouling and the loss of equipment life due to corrosion. If we factor in the loss of one year of a 15-year tube life, the costs double and one cleaning saves twice as much.

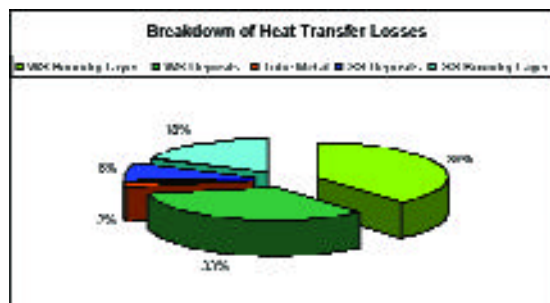
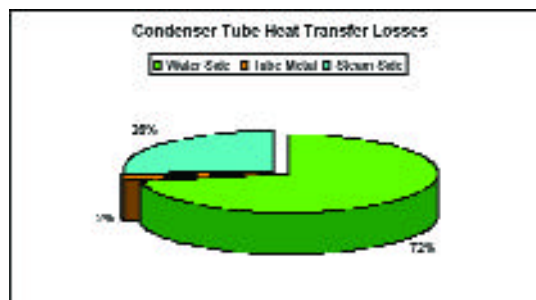


Fig. 4A (top): Heat transfer losses in a condenser
Fig. 4B (bottom): Condenser HT losses breakdown

Is there a way to break the cycle and handle both cleanliness/efficiency and corrosion?

Coatings Will Work to Break the Fouling Cycle

The Electric Power Research Institute (EPRI) published a study on tube coatings (RP-1689-18) in the 1980s. In 1989, John Monday suggested that full-length tube coatings were a possible solution⁹ because they had worked so well in preventing corrosion of water-

boxes, tube-sheets, and tube ends. In 1990, both Japan and Germany offered shop-coated new copper tubing; shop coating of petrochemical HX tubes was done in many countries, including the U.S.; and in Europe (Italy), in-situ coating of condenser tubes was a common practice.

Florida Power Corporation and EPRI conducted a six-year study culminating in a final report, *In-Situ Coating of Condenser Tubes as an Alternative to Retubing*.¹⁰ This extensive report included heat transfer studies and coatings applications in three plant units and a side-by-side test of two waterboxes, one with coated tubes and one with uncoated tubes.

The findings in the EPRI study supported the use of coatings. While the uncoated waterbox required regular maintenance and cleanings, the coated box did not. The uncoated tubes continued to deteriorate, doubling plugged percentage within five years, while the plug rate of the coated tubes remained low. Heat transfer results showed that coatings resistance typically compares with that of a slightly fouled tube, and, while sprayed on coatings do reduce the tube diameter (3-6 mils), this is compensated by an increase in the water flow rate in the tube.

Coating tubes is less costly than re-tubing. Coatings are well under a dollar a



Fig. 7A: Blisters (note white salts)



Fig. 7B: Same tube mid-length

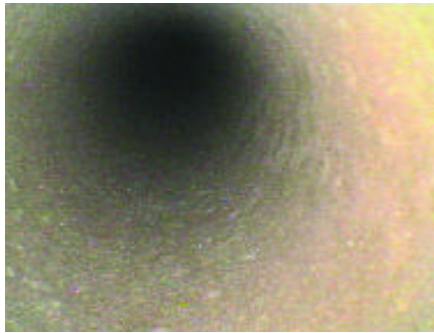


Fig. 8A: Blasted tube SSPC SP-10



Fig. 8B: Coated tube, 3-mils

heat transfer losses. Here, waterside deposits account for about 46% of the HTR and the boundary layer accounts for 54%. These are relative figures for testing on one tube. The percentages will shift with changes in the fouling condition. However, minimizing these two waterside conditions of heat transfer loss will greatly affect the total HTR of the tube and the operating condenser, due to the 72% effect on total HTR.

Condenser & HX Design

Both HEI and the Tubular Exchanger Manufacturers Association (TEMA) intentionally “over-design” heat exchangers and condensers to allow for corrosion and plugging of tubes during their design lives. A 15% over-thermal capacity design is typical. There are also allowances for fouling and cleanliness, and again, a typical HX or condenser will operate with associated fuel cost increases to perhaps a 65% cleanliness or performance factor.

Many of us have used the 15%

plugged limit as a guide to the end of condenser tube life. Also as a general rule for condensers, 20 years in seawater service is a long time. As such, seawater service condensers can require re-tubing two to three times during a plant's life span.

Most industry studies on how and when to clean heat exchanger and condenser tubing demonstrate that cleaning with some established frequency or as a measure of performance pays for itself in reduced corporate operating expenditures.¹¹ Most of these studies do not economically account for the extended operating life of the tubing due to this maintenance cleaning.

Heat Transfer Test Data Results

Without getting too much into the theory, actual heat transfer resistance performance test data show the following.⁹

Based on the dataset in Fig. 5, a coated tube will perform similarly to a typically installed and fouled tube in service without adverse effects on the heat transfer

capability of the tube itself. In fact, the total HTR of coated the tube is less than that of a tube with typical fouling deposits (tube # 4 vs. tube #8 in Fig. 5).

A number of factors account for this. The increase in flow rate and overall heat transfer for a coated tube is accounted for by the reduction of the waterside boundary layer thickness. Less drag means a thinner boundary layer and more heat transfer. Without a reactive metal surface, there are no ionic interactions, such as manganese deposits or oxide formations. The coating is a non-corrosive, inert ceramic or plastic. Less drag means higher flow and less biological and particulate fouling. Silts are not collected, and the smooth surface finish present will inhibit biological growth as well.

The reader should note that, although the tube diameter is reduced by a small percentage (by three mils of coating), the velocity or flow rate through the tube slightly increases to compensate for coating thickness ($P_1V_1=P_2V_2$), so the reduced tube diameter is not a factor. Essentially we have replaced a mud, silt, and blocky oxide deposit with a dense cross-linked epoxy that has an equivalent HTR.

While tube coatings can fail in spots from mechanical or other damage, the copper alloy tube in this area generally turns passive rather than active. An active copper alloy passivates quickly in seawater (a few hours). Pitting occurs without forced passivation in a new condenser because of the extent of the area of tubing and the fact that one area of the tube can be anodic to another. In a coated tube, when a small area of coating fails and the base metal is exposed to seawater, it almost always quickly passivates. If coatings blister, lift, or are permeated by seawater, the area will still be passive and collect brine or salts (passive in copper alloy tubes).

Fig. 6 shows two different coated copper alloy tubes removed from a seawater condenser after 7.5 years' service.

The tubes were cut in a band saw, creating chipping along the edges, but are otherwise "as found." The right (white) tube was lightly wiped with a wet rag to show the extent of particulate and biological fouling and deposit (essentially none).

You don't go through a testing program without failures. Saltwater service, chlorides, and forgetting to reset the cathodic protection system voltage for coated conditions will blister coatings (Fig. 7).

So down-tube, full-length coatings work in all respects. This data has been gathered from 15 years of experience in coating copper alloy tubes in fossil fuel plants.

Blasting is done with special patented nozzles that set up a standing cyclone-generated sine-wave that insures the entire tube is cleaned and well profiled with wearing of the surface confined to no more than 1–3% (Fig. 8A). Coating is conducted with specially patented spray nozzles and procedures that ensure full coverage (Fig. 8B).

Coating Vs. Re-tubing Condensers and Heat Exchangers

Re-tubing larger condensers must be a planned project because it often cannot be accomplished in the time typically allotted for outages. The tubing must be ordered up to 18 months in advance and the work scheduled during a major turbine outage. Utilities are not the only industry with re-tubing schedule/outage duration restrictions. Refinery and chemical plants need to produce, and operating a large hospital, hotel, or sports complex without air conditioning is not feasible.

Typical costs in a fossil condenser re-tubing are in the range of \$4,500/MW. As units decrease in size, the costs go up to \$6,000/MW. So, for a 750 MW unit, it will cost at least \$3.5M to re-tube the condenser (\$2/L-ft tube) with any alloy, provided there are no problems and the outage does not have to be extended.

(The last project I tracked was a 750MW unit with delays and costs of

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\$4/L-ft). These are serious costs, and, coupled with the loss of operating revenues for added downtimes, an option such as coating tubes may be more viable.

Conclusion: Why Coat Tubing?

While coatings on condenser or exchanger tubes will not last as long as retubing (5–10 years vs. 20 years), they have their place in the overall operations, maintenance schedule, and options portfolio, as described below.

First, the coating operations can be done in a typical outage turnaround cycle, and the costs run in the range of 20–35% of those of re-tubing (e.g., for a 750 MW unit, 40,000 40 ft tubes, lead time 45 days, implementation 3 weeks).

If the tubing in your plant or unit does not have 20 more years of service life, the down tube coatings option becomes the most viable economically.

If your unit needs and warrants a full re-tube but you need to buy time to budget, engineer, or make it to a turbine outage four years away, full or partial down tube coatings may be an option to avoid operation unavailability and leaks.

If one waterbox of two or four is limiting your plant's performance capabilities, the tubes in this box can be coated to extend life until you have the opportunity for full re-tubing.

If tube fouling is a problem requiring large maintenance expenditures; then coating tubes should be considered a viable alternative to the continued high operating costs.

Often, we are driven by discharge permit limits. Copper has become a source of problems for many industries. Down tube coatings eliminate almost all copper discharge (about 6 lbs/yr/MW).

The technology and services to apply full-length tube coatings are available now, both in Europe and the U.S.

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