Deferred Heat Exchanger Maintenance
(Can We Afford to Wait?)

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Abstract

With last summer's record power production, spot shortages, and high selling prices, a one day summer outage to plug leaking tubes could result in significant financial impact on the bottom line. Allowing a unit to operate a day or two with the leaking tubes could result in damages exceeding over a million dollars. Additionally, lost megawatts due to exchanger and turbine inefficiency will cause a dramatic loss of income. This paper summarizes some of the possible damage mechanisms, prevention tools, and payback justifications for making the preparatory changes before the problem hits!

Introduction

Managing of a power plant today requires many decisions that can have a major impact on the bottom line. Making the correct one can make the management team heros. The wrong one could mean disaster. Today's fuel costs have increased dramatically. Natural gas has gone from $2.00 per decatherm to over $14.00 at recent peak times (Figure 1).[1] Today's contract prices for coal including transportation costs are approximately double from a few years ago. Any change in operation, such as fouled tubes, can result in a costly heat rate increase. A major condenser, feedwater heater, or boiler tube leak can cause 1 to 3 days of lost power that can result on over $1,000,000 of lost income. Derates during peak periods due to inefficient heat exchangers or copper deposits on the turbine blades can turn a very profitable year into one just marginal.

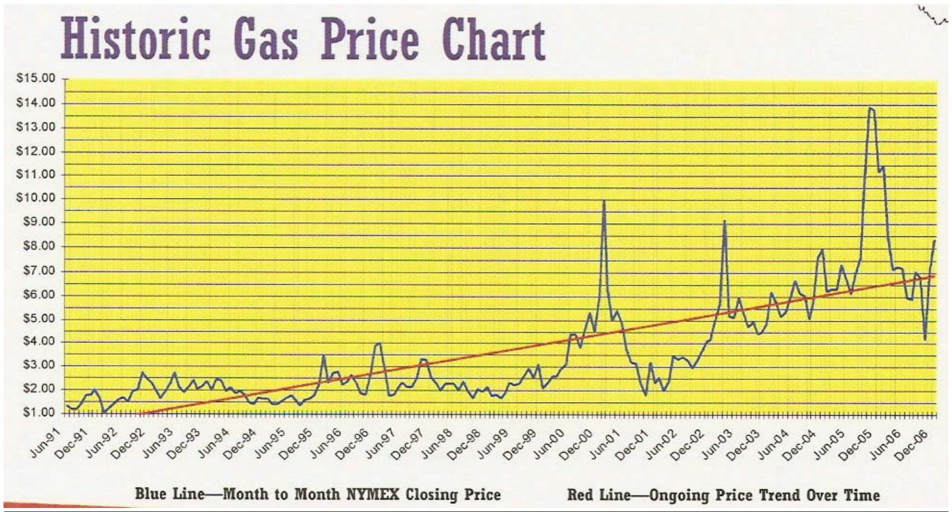

Figure 1. Natural gas prices over the last 6 years.[1]

Tube Failures

A number of potential failure mechanisms are possible in power plant heat exchanger tubing. The mechanisms common in copper alloys are quite different than those for stainless steels and high performance alloys. They are described separately below.

Copper alloys

Steam Side attack

The most common damage mechanisms for copper alloys from the steam side are ammonia grooving and stress corrosion cracking.

Ammonia grooving - When hydrazine and similar derivatives are used to assist with oxygen scavenging, these degrade into ammonia compounds. Admiralty, aluminum brass, and to a lesser extent 90-10 copper nickel, are sensitive to selective corrosion by ammonia compounds. As these are considered non-condensables, the steam drives them into the center of the condenser, the air removal zone. The ammonia combines with the condensate and concentrates on the support plates, running down the surfaces. The ammonia solution attacks the tube surface adjacent to the support plate creating grooves.

Stress Corrosion Cracking (SCC) - When the tubing has relatively high stresses, another mechanism can speed the failure process, stress corrosion cracking (SCC). Both Admiralty and Aluminum Brass are susceptible to ammonia induced SCC. The stresses are commonly developed during the tube straightening operation during manufacturing. This failure mechanism can occur quite rapidly. A condenser having tube failures caused by both ammonia grooving and SCC is not uncommon.

Cooling water side

Erosion-Corrosion –Copper patinas formed under water are usually oxy-hydroxide based and are soft. High water velocities can erode the soft patina exposing the base metal below. A new patina then reforms, and when it reaches a critical thickness, the cycle repeats. This is called erosion-corrosion. For Admiralty and Aluminum Brass, the commonly accepted maximum water velocity to prevent this mechanism is 6 feet per second. However, it is common to see failure in localized areas although the average velocity may be less than 6 feet per second. Turbulence causes localized high velocity; a common example is inlet end erosion. Local obstructions, such as mollusk shells, can also cause localized high water velocity resulting in very quick failure. It is not uncommon to experience tube perforations due to this cause within a few days of inlet screening problems.[2]

H_2S & Sulfuric Acid Attack – Low pH and the presence of sulfur compounds will dissolve protective patina exposing fresh metal. This causes corrosion rates to increase several orders of magnitude. Polluted, stagnant waters create hydrogen sulfide that is generated from the decomposition of marine organisms. When H_2S is present, the copper alloy patina cannot reform its protective surface. Today, new power plants are rarely permitted to use clean fresh cooling water and treated wastewater has become one of the few cooling options available[3]. When cooling water sources are switched from fresh to treated wastewater, 90-10 copper-nickel tubing failures often start within 6 months of the change. Even water containing relatively inert sulfur ions can become aggressive when sulfate reducing bacteria (SRB) are present. The SRB will convert the sulfate ions into the more aggressive species.

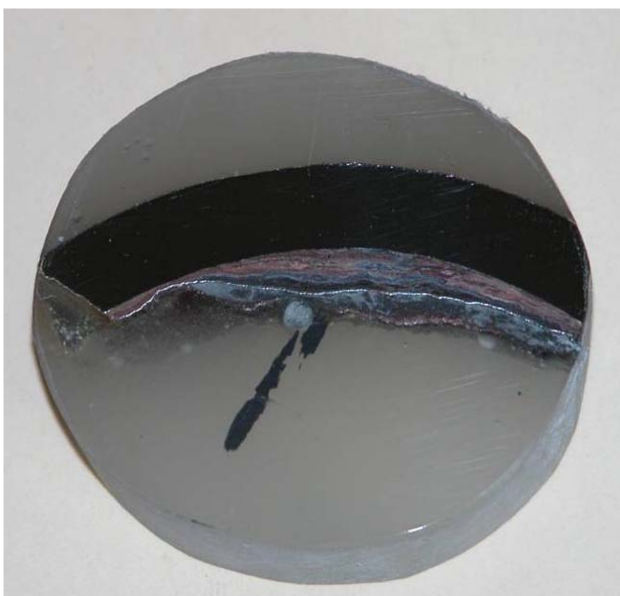

Figure 2, Alternating copper metal and iron oxide layers on boiler tube. Courtesy Hoffman [5]

General Corrosion & Copper Transport

The patina that forms on Admiralty brass, Aluminum brass, and copper-nickel is porous and allows copper ions to gradually diffuse into the water, even under the best conditions. Copper ions are toxic to many aquatic organisms. This is the key reason that copper based paints are placed on marine structures to prevent biological fouling. As the copper dissolves, the tube wall gradually thins. When water conditions are ideal, dissolution rates are slow and 25 year tube life is not unusual. However, the copper transport can still be significant enough to have impact at other locations. For example, the tubes removed from a typical 300 MW Admiralty tubed condenser at time of replacement will weigh about 50% of the original tube weight of approximately 400,000 lbs. This indicates that the 200,000 lbs of copper alloy has dissolved. Both the condensate and the cooling water discharge are candidates. Copper concentrations in condensate can range from 0.2 to 10 ppb depending upon location[4]. Although this concentration appears to be very small, when one considers mass flow rates of millions of pounds per hour range, the over transport can be quite significant. In the closed steam side, it deposits at locations where steam has an abrupt change of volume. Depending upon the plant design, this is often on the boiler tube surface[5] (see Figure 2), or on the high pressure turbine blades. When the copper plates on the boiler tubes, it can initiate catastrophic liquid metal embrittlement of the steel. The situation is aggravated as the deposit layers shown in Figure 2 act as an insulator raising the boiler tube temperature. When the copper is in direct contact with the boiler tubes, the melting point can drop to as low as 2012 degrees F, vs. the typical steel melting temperature of 2700 degrees F. When the copper plates on the turbine blades, the turbine efficiency drops overall plant output is restricted. Although not dramatic, the financial impact can be significant. More on this will be discussed later.

On the cooling water side, Federal discharge limit in most areas is 1 ppm, a relatively easy target to meet unless the tube is actively corroding. However, in many localities, regulators are recognizing that 1 ppm in the hundreds of thousands of gallons per minute that are discharged can amount to a significant amount of copper. In those regions, limits of 40 PPB or less are being imposed. This target is significantly tougher and may require expensive polymer treatments to reducing the corrosion rate.

Stainless Steels

for <u>Steam Side</u>

All stainless steels, both the commodity grades (TP 304, TP 316, and derivatives), and the higher performance versions are resistant to the majority of boiler chemicals including all of the hydrazine derivatives. At higher temperature, one mechanism does cause premature failure, chloride stress corrosion cracking (SCC).

SCC – Stainless steels containing 2% to 25% nickel are susceptible to cracking when a combination of stress, chlorides, and temperature are present. Those containing 8% nickel (TP 304) are most sensitive (Figure 3). The minimum critical temperature for TP 304 is approximately 150 degrees F. Because the metal temperature in condensers and lower temperature BOP exchangers is below the critical temperature, it is extremely rare TP 304 and TP 316 to fail from this mechanism in those exchangers. SCC can occur feedwater heaters when the steam chemistry has had a chloride excursion. Usually, this occurs when a condenser tube leaks and the plant continues to operate. The damage can be extensive, sometimes requiring replacement of the heater. The failure mechanism has also become more common in plants that have switched from base load to cycling modes. The chlorides concentrate in regions that alternate between wet and dry, primarily in the desuperheating zone or in the adjacent area of the condensing zone.

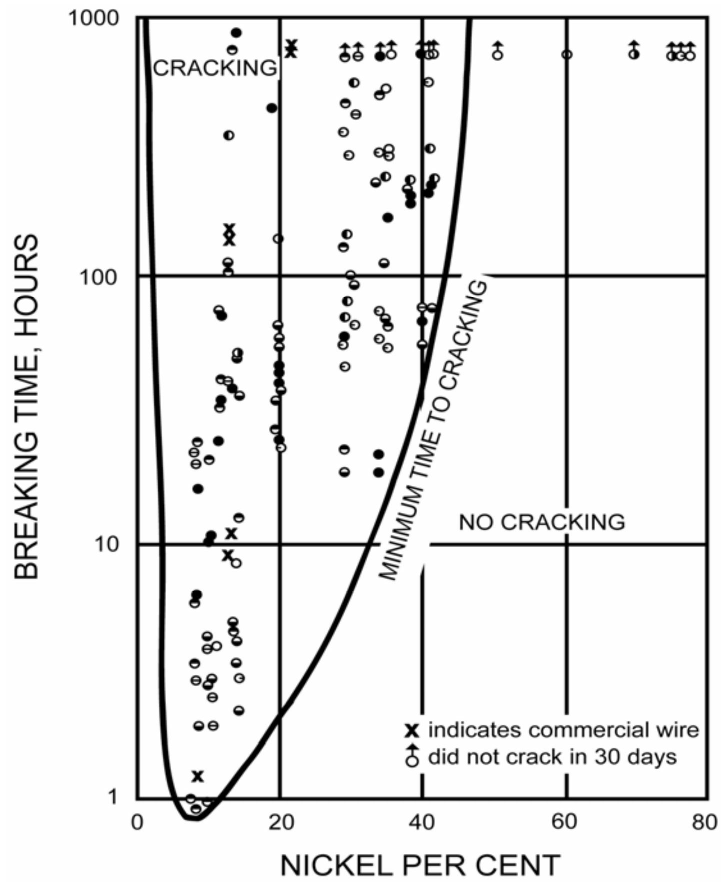

Figure 3. Time to failure of Fe, Cr, & Ni wires in boiling magnesium chloride vs. nickel content.

<u>Cooling water side</u>

Pitting and crevice corrosion – TP 304 and TP 316 are susceptible to pitting, crevice corrosion, and MIC related crevice corrosion in many waters normally considered benign. TP 304 and TP 316 should not be considered if the cooling water has chlorides that exceed 150 ppm and 500 ppm respectively (Figure 3). An expert should also consulted if the manganese levels are higher than 20 ppb or iron levels exceed 0.5 ppm. Like copper alloys, TP 304 and TP 316 should not be considered candidates if treated wastewater is the cooling water source. A detailed discussion this topic and SCC can be found in the paper by Janikowski[6].

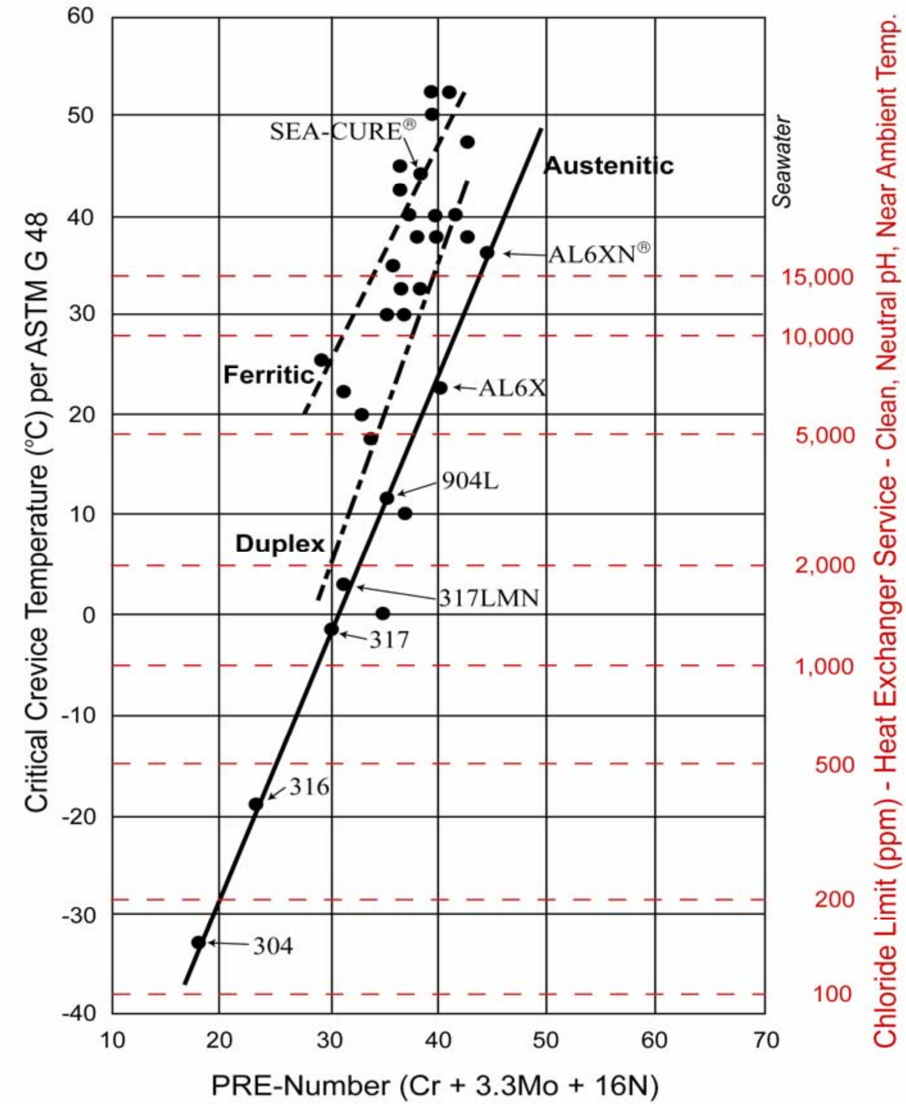

Figure 4 Critical Crevice Temperature and Maximum Chloride Levels Versus PREn of Various Stainless Steels

Titanium

Titanium grade 2 is normally considered immune to any of the pitting and crevice corrosion mechanisms common in the power generation cooling circuits. One exception may be the crystallization equipment used in zero discharge plants. In this equipment grades 7 or 12 may need to be considered. However, because of its low modulus of elasticity, it is susceptible to vibration damage. This can be prevented by proper design.

Fouling

Condenser tube fouling is a common cause for increasing heat rates and can be expensive expensive. Fouling can be due to either biological factors or scaling. The layers are thermal barriers that raise steam saturation temperature and turbine back pressure. Even Nuclear plants that have low fuel costs and megawatt restrictions can be affected as fouled heat exchangers result in higher fuel burn rates that can shorten the time period between refueling outages. It would not be unusual to see additional fuel costs of $250,000 annually for a mid-sized coal fired plant[7], and more for plants with higher cost fuels, such as gas or oil fired.

Another, and potentially larger concern, is the damage of the tubing under the deposit due to under-deposit or crevice corrosion. Once the surface is covered, it is no longer flushed with the bulk cooling water and the contaminates, such as chloride or sulfur, concentrate. With a drop in pH, the acidic condition attacks the passive surface layer initiating a corrosion cell. As this cell encourages further concentration, attack can be very rapid. It is not unusual to see through wall attack in 3 weeks on an improperly laid-up .028" thick TP 304 condenser tube.

Scaling, due to the heating of cooling water saturated with calcium carbonate, gypsum, or silica, can precipitate surface deposits that can significantly lower heat transfer. These constituents have inverse solubility which means that they become less soluble as the water temperature increases. Often, the deposits are thicker in the latter passes, or higher temperature section of the condenser. It is common in some plants with cooling towers or cooling lakes with high evaporation rates to see cleanliness factors, when calculated by the HEI Condenser method, to be in the 50% to 65% range. A good overview on this scaling is detailed by Howell and Saxon[8].

The Value Comparison

Many operations do not summarize the total costs related to a problem heat exchanger. Justification for your cleaning and/or retubing starts with a defendable Value Comparison summary. It should be based upon a "life cycle" basis and not solely on the lowest initial cost. Operation of many existing power plants are expected to be cost justified for another 20 years. The analysis should be developed for the remaining life time of the plant.

The individual components that can be used for building the analysis include:

- Initial tube cost
- Installation costs
- Fuel savings based on higher thermal performance
- Lower cooling water chemical treatment costs
- Reduction of lost generation due to turbine efficiency losses
- Reduction or elimination of boiler tube and high pressure turbine cleaning costs
- Elimination of emergency outages / derates to plug leaking tubes.

Following is a model example that can be followed to help determine the true cost of running with the existing tubing versus comparing the cost of replacing with new tubing. Although developed for a steam condensing application, the pattern can be used for feedwater heaters, or balance of plant exchangers. The example is based on a condenser for a 300 MW coal fired plant currently using 16,400 1" OD x 18 BWG (0.049 average wall thickness) 90-10 copper nickel tubes that have an effective length of 42.2 ft. The steam load is 1,480,000 lbs per hour with an enthalpy of 950 BTU / lb. On this unit, the turbine exhaust area is 375 square feet. The circulating pumps provide a design flow of 114,000 gal/ min that result in a design head loss through the tubes of 19.58 feet. At this time, 6% of the existing tubes are plugged. Scaling is minimized through aggressive water chemistry controls providing an HEI[9] cleanliness factor of 85%. The condenser was designed for an inlet water temperature of 85°F, which is a common inlet water temperature in early Summer and early Fall. However, it can be higher during mid-Summer.

In our model, tube leaks are now occurring approximately twice per year, particularly during peak summer season (hotter temperatures increase corrosion rates). Every 4-5 years the high pressure steam turbine needs to be cleaned due to copper plating on the turbine blades. During this time frame, the overall drop in plant capacity is 21 megawatts. The original tubes lasted 22 years but because of change in cooling tower operation and new water sources, the expected life of the new 90-10 copper nickel tubing may only be 10-15 years. As this is a closed cooling tower plant, the service water has been chemically treated with ferric sulfate to assist repassivation of the copper nickel after excursions of cooling water chemistry due to efforts to keep the tubes and cooling tower clean. This cooling water is aggressive to many alloys requiring selection of an alloy resistant to high chlorides and microbiological influenced corrosion (MIC). The alternative candidates that this utility is considering are titanium grade 2, AL6XN® high performance austenitic stainless steel (UNS N08367), and SEA-CURE® high performance ferritic stainless steel, all proven to have a good track record in similar water. TP 304 and TP 316 are not candidates for this condenser as the chloride levels commonly climb over 700 ppm, and Mn and Fe levels are high[6].

The HEI Standards for Steam Surface Condensers[9] are an excellent basis for comparing the thermal and mechanical performance of the various tube materials. In addition to determining back pressure, the potential for vibration damage, and changes in uplift can also be evaluated. The initial results of the analysis are included in Table 1.

When titanium or stainless steel tubing is selected for a condenser retube, it is common to choose 22 BWG (Birmingham Wire Gauge) or 0.028 inch, as the tube wall replacement. Stainless steels have a higher modulus of elasticity than copper alloys. Because of the higher modulus, thin wall stainless tube can be as stiff than the thicker wall copper alloy. This minimizes the impact of vibration. Although titanium's modulus of elasticity is lower than copper alloys, the high material price requires titanium to be used in thin walls, as well. This requires a change in design philosophy. The combination of thicker ID and OD patinas on copper alloy tubes designs that use lower cleanliness factors than the stainless stainless steels or titanium. Compared to 85% commonly measured for clean copper alloys, the stainless steels and titanium traditionally exhibit HEI cleanliness of 95% or better. In many cases, the stencil on stainless and titanium tubes that may have been in service for several years may still be read. For our calculations, 95% is used.

Although the original design flow was 114,000 gal/ min., flow will vary as the head loss changes. The low head / high volume pumps used for circulation water purposes have mass flow rates that are highly sensitive to head loss. For example, the 1.5 foot head increase caused by plugging 6% of the tubes may result in a typical 2% decrease in cooling water mass flow. Conversely the 3 foot head decrease by changing to 0.028" wall thickness tubing from 0.049" wall original tubing can result in a typical 3% to 4% increase in mass flow. We've included 3% in our calculations to be conservative. If available, the specific pump curve(s) for the plant should be used. The cooling water velocity is calculated to determine the temperature rise in the tube. Although normally considered to have a significant impact on the condenser performance, the cooling water mass flow is the key factor for removing heat.

In this analysis, we've used the design inlet water temperature for the basis. When the plant has an undersized condenser and this condenser is limited during peak summer conditions, we may consider using the maximum inlet water temperature for our analysis. When we do this, the results accentuate the different material thermal performance.

Alloy		**90/10**	**90/10 - 6% plugged**	**Ti Gr 2**	**N08367**	**S44660**
Wall	Inches	**0.049**	**0.049**	**0.028**	**0.028**	**0.028**
Cleanliness		**0.85**	**0.85**	**0.95**	**0.95**	**0.95**
Cooling Water	Gal/min.	**114,000**	**111,720**	**117,420**	**117,420**	**117,420**
Velocity	Ft/sec	6.98	7.28	6.56	6.56	6.56
Inlet Temp	^{o}F	**85**	**85**	**85**	**85**	**85**
Back Pressure	In. Hg	**2.94**	**3.00**	**2.78**	**2.86**	**2.79**
HEI Calc. Span	Inches	**36.87**	**36.87**	**31.39**	**36.26**	**37.56**
Vibration?		**Original**	**Original**	**Much More likely**	**More likely**	**Less likely**
Uplift	Lbs	**0**	**0**	**(203,885)**	**(113,704)**	**(122,225)**
Est. Fuel Cost	$/MBTU	**$2.50**				
Est. US$ saved /year from 90/10 based on 0.1 in Hg = 15 BTU/KWHr			**($58,968)**	**$157,248**	**$78,624**	**$147,420**

Table 1 Comparison of thermal and mechanical of various condenser tube candidates for a 300 MW unit using HEI Standards for Steam Surface Condensers

After the cooling water, steam flow, and tube alternative parameters have been determined, the saturation temperature is calculated and the back pressure is found using the steam tables. A lower back pressure, or better vacuum, is desired, which increases turbine efficiency. For this condenser, the 6% plugged tubes created a back pressure increase of 0.06 in. Hg. HEI predicts a very significant back pressure drop of 0.16 inches for titanium and slightly lower 0.15 inches for the super ferritic S 44660. With higher thermal conductivity, the drop in pressure for the super austenitic N 08367 is approximately half at 0.08 inches.

Over the years, many different vibration methodologies have been developed to calculate a "safe span" that results in no tube damage. Each of these uses a different series of assumptions. The HEI span reported in Table 1 assumes that the condenser tube will vibrate and that the support plates shall spaced to keep the vibration amplitude equal to or less than 1/3 of the ligament spacing. When two adjacent tubes are vibrating, the design allows for an additional clearance of 1/3 of the ligament preventing tube-to-tube collisions. Although the absolute value for a safe span for a specific tube material may vary significantly depending upon the method used, the different methods are in relative agreement of the proportional span relationship between alloy and wall for the same OD. If the specific method predicts a longer span for a proposed tube selection, this alternative is considered more conservative, or safer. If the method predicts a shorter span, the alternative selection is riskier. In this analysis, HEI predicts a span of 36.87 inches for the Cu-Ni. The calculated span for titanium is almost 5 inches shorter which suggest that the risk of vibration damage is high, unless other preventative measured are used. N08367 has a slightly shorter calculated which suggests a slight increase in risk for vibration damage. Only the S44660 has an HEI calculated span longer than the Cu-Ni. The most common solution to preventing vibration problems is the installation of "stakes" mid-span between the support plates. Wedged between the tubes, the stakes are additional supports. Any vibration criteria has its strengths and weaknesses and a qualified expert should be consulted to ensure that proper staking is used with any tube option.

Copper-nickel has the highest metal density of any traditional condenser tube candidate. When combined with the thick initial wall thickness, all of the alternates will result in a condenser of significantly less weight. The difference in pressure across the large turbine exhaust area can create significant uplift. When this condenser is at 1.5 inches of back pressure, the uplift due to the vacuum is approximately 700,000 lbs. If another tube is selected, the drop in tube weight could result in damage to the supports. Switching to titanium tubing results in a weight reduction of 204,000 lbs. If titanium is selected, the specialist should be consulted to check if reinforcements are needed in the anchoring areas.

The change in back pressure will have an impact on heat rate, and ultimately the change in the amount of fuel that will be used. As this is a coal fired plant, we've assumed that the delivered cost for the coal over a 20 year period will average $2.50 per million BTU. For this plant, we've determined that for each 0.1 inches of Hg change in back pressure, the plant will save or require 15 BTU for each kWHr. Currently the increase in back pressure due to the current 6% plugged tubes is costing us about $59,000 per year in additional fuel costs. If we decide to switch tube material, we can then calculate an additional fuel savings of $157,000 per year if titanium is chosen, $79,000 per year additional if the super austenitic N08367 is selected, or $147,000 additional per year if the super ferritic S44660 is final choice.

Now that we've determined what we may need to do special for each material that we are considering, we need to make a few more assumptions to complete our Value Comparison Summary. We've decided that we expect to see this plant commercially viable for approximately 20 years. Although we have a risk that the water chemistry may become more aggressive, we believe that our chemists have enough control over the cooling water that we will continue to keep the tubes clean and that we can control pH and biological content so that 90-10 copper nickel will last the 20 year period without an additional retube. The other candidates have an excellent track record for doing the same, even if we have water chemistry excursions. We've requested budgetary tube costs from the tube suppliers and have an estimate which has been included in our summary, which is detailed in Table 2. During discussions with potential tube installers, we've found that the cost to install the various alloys is not significantly different, at approximately $250,000. Our consultant has recommended some staking due to the lower stiffness of the titanium and the N08367 tubing; significantly more for the titanium than the austenitic stainless. Based upon the consultant's recommendations, our installers have quoted an average of $200,000 for the titanium and $50,000 for the austenitic. The consultant is also concerned about the additional uplift if titanium is chosen. We've included $50,000 in the budget for reinforcement of anchor points.

At this point, we start including what we estimate our operational and maintenance costs are for the various candidates. Base upon the fuel costs that we calculated in Table 1, we expect a savings of $3.1 million over 20 years for titanium, $1.55 million for N08367, and almost $3.0 million for S44660, compared with 18 BWG copper nickel. Our experience with the copper nickel tube is that we will get occasional tube leaks, predominately from erosion corrosion from entrapped debris. We estimate that this will

Alloy Option	**90/10 18 BWG**	**Titanium 22 BWG**	**N08367 22 BWG**	**S44660 22 BWG**
Estimated Tube Purchase Cost	**$2,200,000**	**$2,900,000**	**$3,300,000**	**$2,000,000**
Installation Charges	**$250,000**	**$250,000**	**$250,000**	**$250,000**
Staking Cost	**$0**	**$200,000**	**$50,000**	**$0**
Anchoring Improvement	**$0**	**$50,000**	**$0**	**$0**
Fuel savings - 20 years	**$0**	**-$3,144,960**	**-$1,572,480**	**-$2,948,400**
Derate to fix tube leaks - 1/ yr for 5 years, 2 / year after	**$4,875,000**	**$0**	**$0**	**$0**
Chemical treatment $100,000 /yr	**$2,000,000**	**$0**	**$0**	**$0**
Turbine cleaning every 4 years	**$1,000,000**	**$0**	**$0**	**$0**
20 year total cost basis	**$10,325,000**	**$255,040**	**$2,027,520**	**-$698,400**
20 year savings	$0	**$10,069,960**	**$8,297,480**	**$11,023,400**
Approx. years for payback vs. Cu-Ni	$0	**6.8**	**8.7**	**4.1**
Optional: Lost MW from Copper on HP Turbine -Avg 5 MW/yr loss @ $55 / MW, 85% operation time	**$40,953,000**	**$0**	**$0**	**$0**

Table 2 Value Comparison Summary - Estimated 20 year installation and operating costs of various tube candidates for 300 MW power plant condenser.

occur per year during the first 5 years and twice per year after 5 years. Fortunately this condenser was designed as a divided flow design so that we do not completely need to shut the plant down to fix the leak. To locate the leaks and plug the tubes, it normally takes us 2 days. During a derate of that time frame, we typically loose $225,000 of income. As the other tube candidates are not susceptible to erosion corrosion, no cost was assigned to them.

Our traditional cost for chemical treatment (pH adjustment, ferrous sulfate treatments, others) to protect the copper tubing has been costing about $100,000 per year. These will not be required, or will be minimal, with the other alternatives.

On this plant design, it is not unusual to see a significant drop in plant output due to copper buildup on the HP turbine blades as shown in the example in Figure 5 [10]. Copper deposits build on high pressure turbine blades lowering the efficiency of the turbine, and restricting the overall plant output. Approximately every four to five years, the derate is significant enough to justify cleaning the turbine at a cost of approximately $250,000. As all of the copper based feedwater heaters have been replaced with other alloys, the only remaining source for copper is the condenser. If we choose titanium or the high performance stainlesses, this cleaning cost disappears.

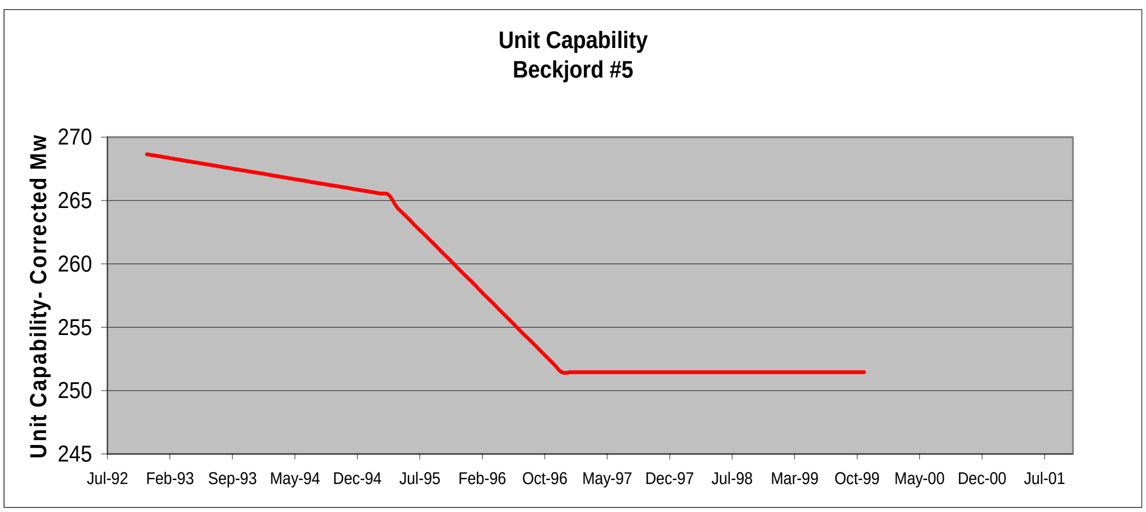

Figure 5 Loss of MW capacity due to copper plating on the HP turbine blades for a 270 MW plant. Source Burck & Foster[10]

Summing of the installation, operation, and maintenance cost components that we've considered so far, and not including the base 90-10 related fuel cost, we see some very significant differences for the condenser tube candidates. The combination of derate to fix tube leaks, water chemistry control, and additional cleaning required due to copper transport, has added over $10,000,000 to the cost directly related to the use of copper nickel condenser tubing. Although the installation & tubing costs of the titanium option and N08367 option are significantly higher, this is mitigated by a significant fuel saving (vs. Cu-Ni) for titanium and to a lesser extent for N08367. The 20 year fuel savings pays for approximately 92% of the titanium installation costs and about 44% of the N08367 costs. With S44660 lower initial cost and excellent thermal conductivity resulting in good fuel savings, the installation & tube costs are paid for by fuel savings alone in 14 years.

One very significant performance penalty was not included in the 20 year analysis, but is identified in the last row of Table 2. Copper deposits on the HP turbine blades can have an enormous financial impact. Derates of 20 MW or greater is possible on a plant of this size after a four or five year period. Using the following assumptions:

- The turbine is cleaned every 4-5 years,
- The average MW derate is 5 MW,
- The plant is in operation 85% of the time,
- The average selling price is $55 per MWHr (based upon the average selling rate at the Cinergy hub)[1]

The total income lost over the 20 year period is $40,953,000! This emphasizes how important it is to keep the plant operating efficiently, particularly keeping the turbine free from copper deposits.

Summary:

Keeping our exchangers, particularly feedwater heaters and condensers, operating efficiently is critical to the bottom line. Not only are current operations and maintenance important, but materials selection for the performance of the exchanger and impact in the balance of the system need to be considered. Today, we have many more commercial material choices than we had 25 or 30 years ago. Factors to consider and manage are:

- Tube cleanliness,
- Tube material and thickness,
- Installation costs including modifications,
- The selections impact on heat rate,
- The impact of copper transport,
- The cost of condenser tube repair including lost MW,
- The cost of emergency shutdowns due to boiler tube repair including lost MW,
- The cost of chemical treatments,
- Lost MW due to undersized condenser,
- And, the cost of lost MW due to lost efficiency.

Proper planning, maintenance, and materials selection can turn a borderline operation into a big winner. We cannot afford to wait.

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