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CALGON CORPORATION

SUBSIDIARY OF MERCK & CO., INC.

CALGON CORPORATION CALGON CENTER BOX 1346 PITTSBURGH, PA. 15230 (412) 923-2345

July 20, 1977

International Paper Company
Georgetown, SC 29440

Attention: Mr. R. V. Touchette
Mill Manager

SUBJECT: Metallographic Report

Gentlemen:

Attached is our laboratory report of the metallographic examination of a failed tube from the No. 1 Power Recovery Boiler. This failure was detected on June 3 at a point near the mud drum in the bottom row of tubes entering the drum on the side away from the furnace (the cooler side). The actual failure was in the shape of a "V" approximately 3/16" diameter on the inside surface of the tube culminating in the pinhole on the outside surface. Just adjacent to this V-shaped hole was a heavy layer of what appeared to be pure copper approximately 3/8" diameter and 0.025" in thickness. The top and the bottom of the tube were not indicated, but there was a slightly acid attacked channel area which we assumed to be the bottom of this nearly horizontal swaged tube. The copper plated area and the pinhole failure are located in approximately the 7 o'Clock position relative to this acid damaged area. Further, it should be noted that the pinhole failure is in the transition zone of the swaged tube.

The attached report contains both macro and micro photos taken to characterize the failure. The observed microstructure is normal and there is not any evidence which points to the cause of the failure or to the cause of the heavy copper plating.

The tube section received was thoroughly brushed to remove deposits and the sample was identified by X-ray diffraction, microscopic examination and emission spec as follows:

MAJOR:	Magnetic iron oxide (magnetite)
MINOR:	Copper metal
LOW MINOR:	Ferric oxide (hematite)
TRACE:	Hydrated ferric oxide Calcium phosphate (probably hydroxyapatite)

The quantity of deposit present was small and perhaps the only unusual condition observed is the somewhat high amount of the copper metal present. The report indicates the concentration of copper to be between 8 and 15%.

I understand that George Bessent from Calgon and others examined tubes entering the mud drum very carefully and could find no indication of other tubes that might contain a similar localized heavy layer of copper or deep pits. This failure is unique in my experience and that of others here in Pittsburgh and cannot be explained by any of the corrosion mechanisms we have encountered.

Very truly yours,

WATER MANAGEMENT DIVISION

R E Elliott

R. E. Elliott
Market Manager
Paper Chemicals

kld

Enclosures

cc: H. K. Wilson, Jr.
George Ellis
D. C. Bourne
E. P. Scheu
G. R. Gardner

bcc: R. J. Beuc
G. L. Bessent
G. E. Starr
File
Birmingham Office
Mobile

bPS: Gayle Starr

Attached to your copy of this letter are additional photographs not included in the report. You might want to show these to Herman or others to help describe the condition of the tube. The remaining pieces of the tube section and the mount are also being returned to the Charlotte Office separately.

There is so little basis for the theory I proposed to you on the phone, that I did not have the courage to include it in the letter but I will put it down in the postscript. If there was a flaw in the metal (there was no evidence of flaw by microscopic examination), this flaw could have trapped acid during the acid cleaning that was not drained or neutralized before operation of the boiler. With increased heat, this acid would then begin to spend itself in the flaw area and generate significant concentrations of hydrogen. If at the same time as this some debris not removed with the cleaning laid down over the surface of this pocket of acid, the hydrogen generated by the corrosion in the flaw could have reduced the copper in the overlying deposit and caused the heavy plating. To carry this logic further, the acid would have spent itself before actually creating a failure at that time (February 1975), but have penetrated the tube wall enough so that during the two and one-half years since that cleaning, failure did occur. Or perhaps there was a small weep just after the 1975 acid cleaning and it became plugged with metal oxides so that the leak was not detected until just recently. Wild!

Ed

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INTERNATIONAL PAPER
GEORGETOWN, SOUTH CAROLINA

SUBJECT: Failed Boiler Tube
Lab #D7592

A section of failed boiler tubing from the No. 1 Power Recovery Boiler was received for examination. The failure consisted of a small pinhole through the tube wall.

PROCEDURE

The tube was sectioned through the failure and a portion was acid cleaned (Figure 1).

A specimen, which was a cross section of the failure, was mounted, polished, etched and examined microscopically. A photomicrograph was taken of the microstructure in the failed area at 360X (Figure 2).

OBSERVATIONS

The inside wall surface of the tube showed some signs of a general pitting. (Figure 1)

A copper plug was observed in the area of the failure (Figure 1). Figure 3 shows the cross section of the copper plug and tube wall in the area of the failure.

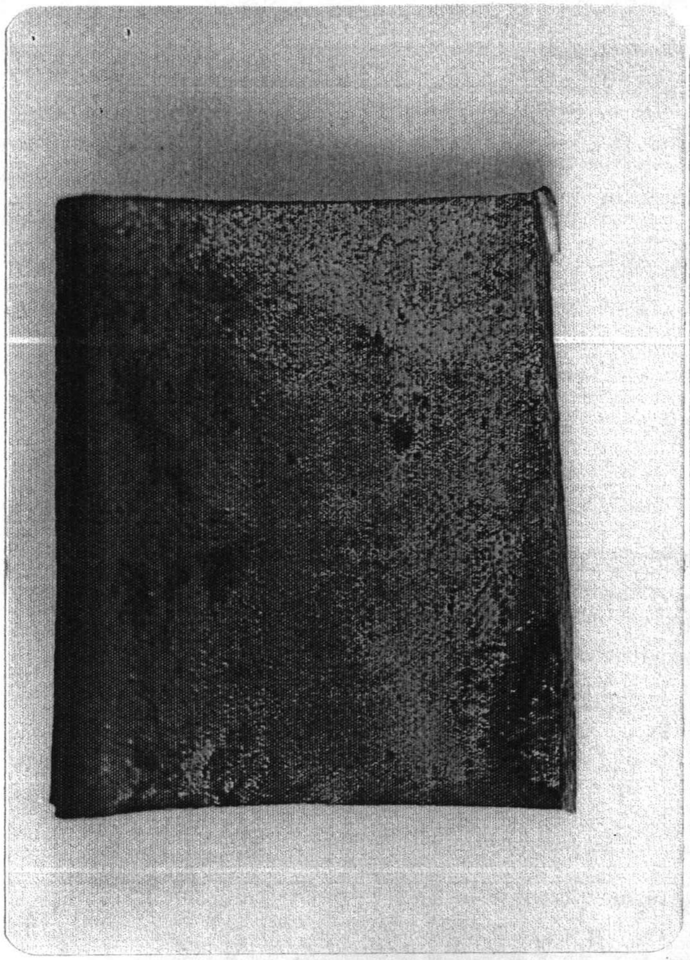
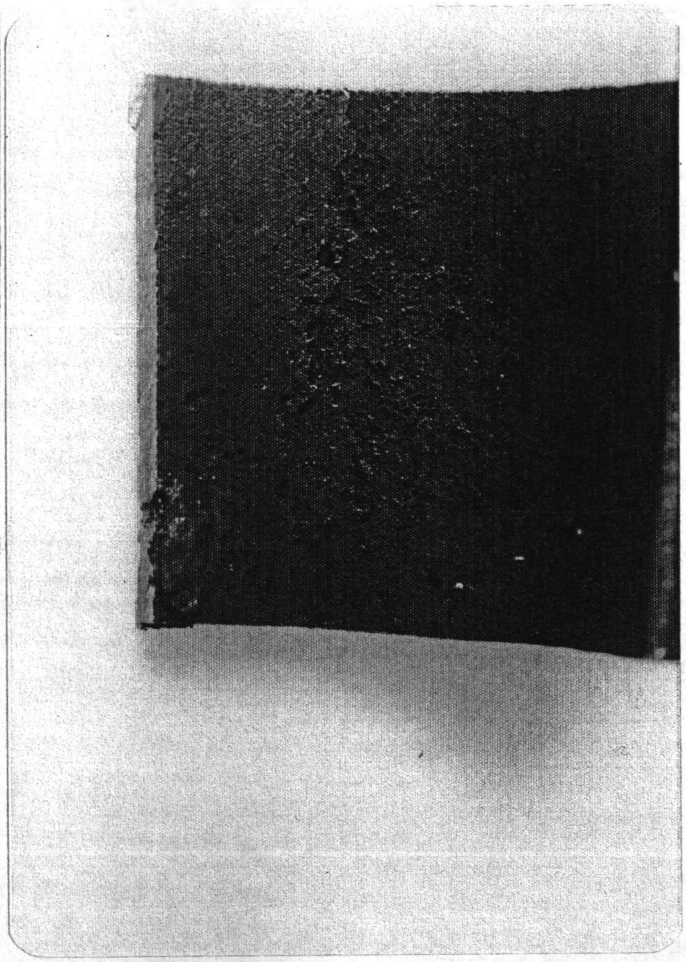
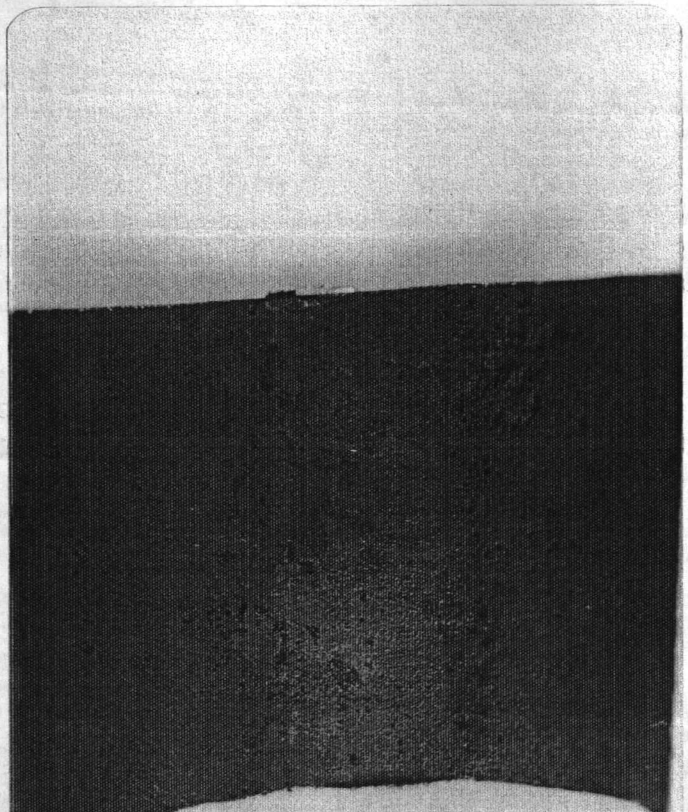
The microstructure directly under the plugged area appeared to be normal. Lamellar pearlite and dense colonies of spheroidized carbides were observed in the microstructure near the interface of the base metal of the tube and the copper plug (Figure 2).

CONCLUSION

Some form of a concentrated corrosion attack around or under the copper plug appeared to have caused the pinhole failure. Evidence as to the exact nature of the attack was not observed in the examination.

HKKolavick
H. K. Kolavick

7/18/77

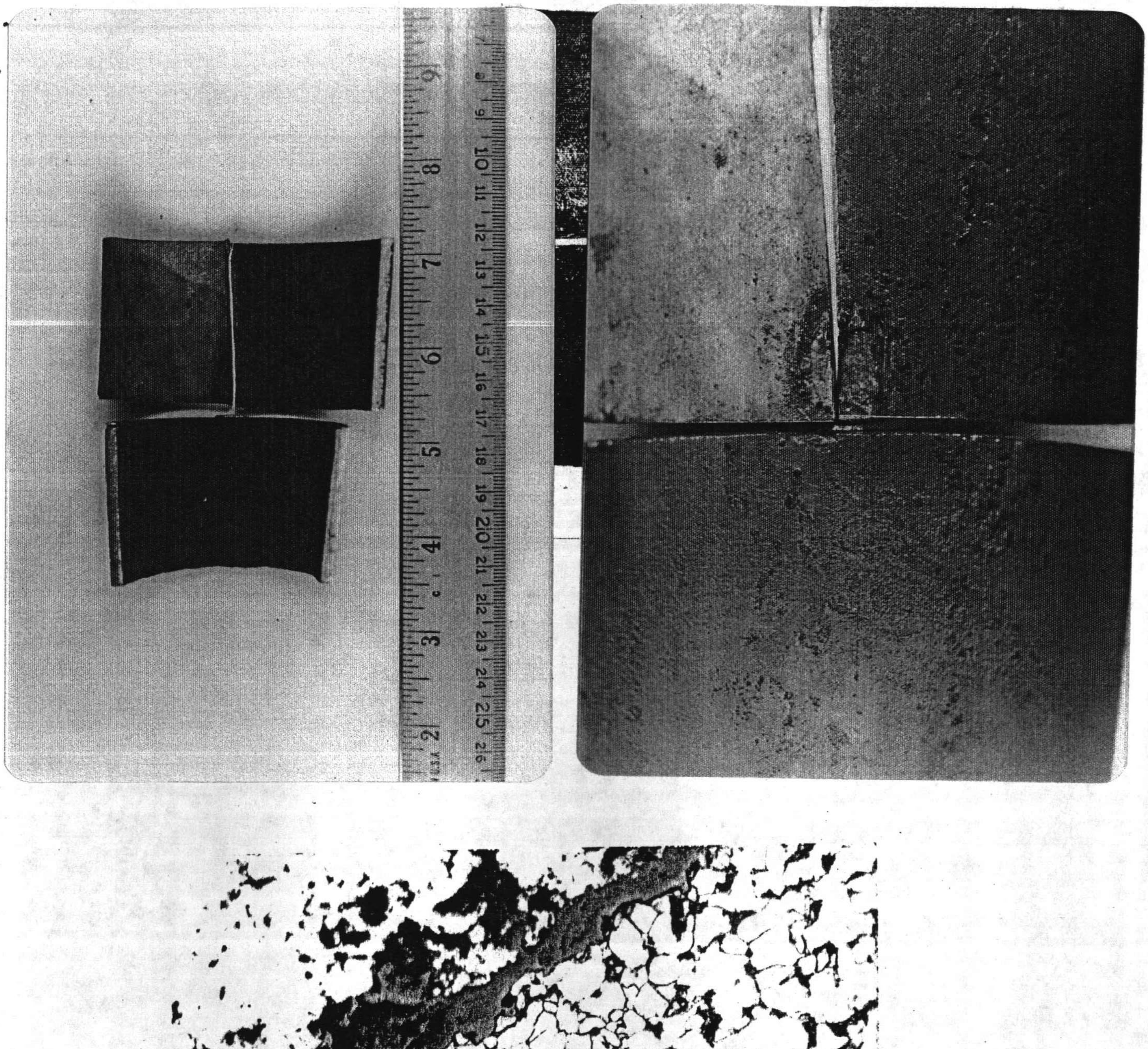


Figure 2

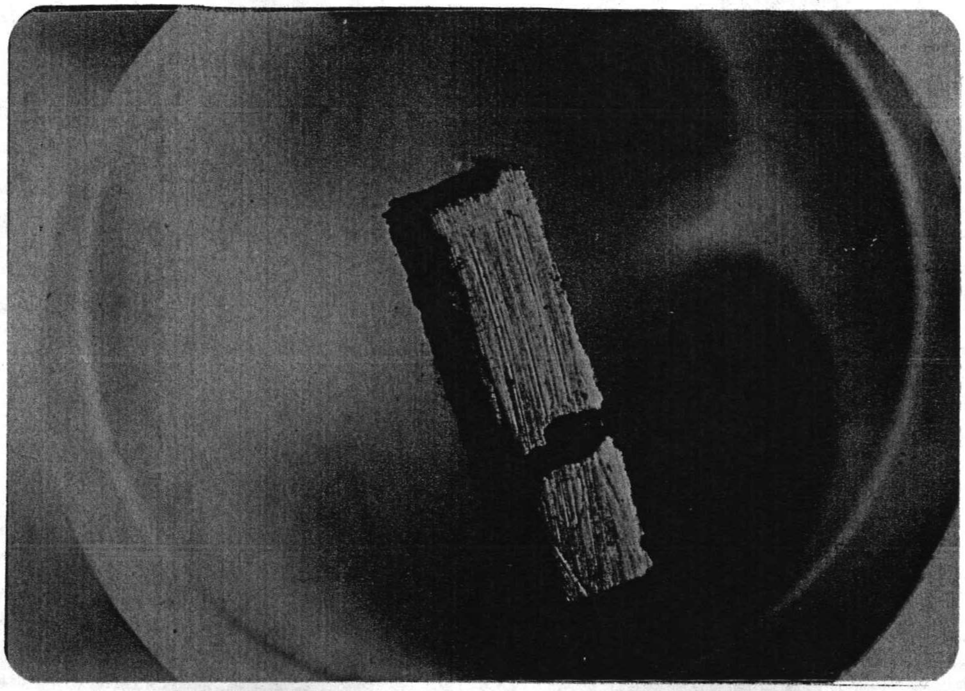


Figure 3

CALGON CORPORATION

SUBSIDIARY OF MERCK & CO., INC.

INTEROFFICE CORRESPONDENCE
CALGON CORPORATION

DATE: June 24, 1977

TO: Gayle E. Starr

FROM: R. E. Elliott

SUBJECT: INTERNATIONAL PAPER
GEORGETOWN, SC

The tube section you sent in from the No. 1 power recovery boiler has got to be one of the most unique failures I have ever seen. I had the lab cut through the failure and it is almost a perfect v-shape, not the typical clear like gouge that would be encountered with caustic attack. On cutting through it became apparent that there was overlying the effective area about the thickest layer of copper metal I have ever seen deposited in a boiler. I have brushed out the tube thoroughly and submitted the removed deposit for identification.

After brushing out the deposit, it became evident that there is a channel, approximately 1/2-inch wide and 1/2-inch removed from the failure that is clearly undercut and probably represents damage during acid cleaning. This is simply an observation and I can't see any obvious connection to the failure.

If we are to do any metallographic work on this specimen, we would have to cut out a piece of metal including the failure to be mounted and polished. If we do this, there would be little point in returning the tube section to Georgetown as requested in your 6/22/77 memo. I will hold the tube section before proceeding with the metallographic until I am able to talk with you, which will probably be sometime after July 5 when I return to the office.

Ed

R. E. Elliott

kld

cc: G. Bessent
R. S. Byron
T. W. Hubner
Charlotte Office
WMD File

MEMO

TO E. K. Lederach

FROM F. H. Seels

SUBJECT Procter & Gamble, Ivorydale Plant
No. 4 Boiler, Crossover Tube Corrosion

CALGON
SUBSIDIARY OF MERCK & CO., INC.

DATE 3/1/84

This is a report on the crossover tube specimen received from the subject customer. As was stated in my preliminary report of 1/31/84, the principal cause of metal loss is erosion-corrosion, most probably associated with cavitation.

Boiler Observations - Description of Overall Problem

At the start, it is important to understand the nature of the problem under study, and how this specimen relates to the particular boiler involved. Because I am not a first hand witness to boiler inspection observations, I rely on Jim Stephens' inspection findings, as summarized in his 10/3/83 report (copy attached).

There are several important features of the overall crossover tube corrosion problem:

1. Metal loss is very localized.
2. Metal loss is local to geometric features of changing flow direction and changing pipe diameter.
3. Metal loss is in a "no heat flux" area.
4. Metal loss is in an area of two-phase flow.
5. Boiler design and water chemistry are very traditional; there is no knowledge of similar metal loss problems among the technical staff of Combustion Engineering or Calgon Corporation.
6. 1983 measurement of metal loss rates indicate that metal loss is an active and substantial process. Thus, the origin of the problem would extrapolate to recent years, not to boiler start-up in the 1960's.

Specimen Observations - General Patterns of Localized Metal Loss

Examination of the tube specimen studied for this report involved many observations with a 20-80X stereo microscope as well as metallographic and SEM observations which are summarized by the attached photographs 1-17. Generally, the waterside surface is characterized by a dark reddish-brown coating several mils thick. Corroded areas have a blackish semi-gloss oxide coating.

Stereo microscope observations gave a strong sense of directional orientation to the patterns of metal loss. Even the naked eye can see metal loss patterns that are closely paired with features of tube geometry. For example, photos 1, 2 and 3 show:

1. Gross metal loss in a circumferential band immediately upstream of a weld. The weld is a precisely engineered distance from the tube inlet/header connection. The weld is associated with a reduction in inside tube diameter.

2. Lesser metal loss of less uniform character, beginning at a distance of 0.5 inches downstream of the weld and extending an additional distance of 1.0 inches, thus forming a circumferential band of pitting-type attack. The despositional texture of non-corroded surfaces in this band is notably smoother than the dimpled texture further downstream away from the pitted area. Photo 3 shows the combination of smooth surface deposits and localized metal loss in the area left of center. A dimple surface texture, free of corrosion is seen in Photo 3 in the area right of center.

3. Metal loss areas in general, have a circumferential orientation. However, another characteristic is highly irregular size and shape of individual corrosion sites. The corroded areas are clearly defined by a sharp edged appearance. The shape of these areas is often channel-like. The channel shapes are often oriented at odd angles to the tube axis and have an irregular aspect ratio (width to length). This is particularly true of the area downstream of the weld (Photo 3).

4. Some corrosion channels are oriented circumferentially (i.e., adjacent to weld, Photo 2); some are longitudinal (Photo 3); some are at (approximately) 45° angles (Photo 2); some have an altered orientation and are L-shaped.

5. Sharp edged features are typically associated with undercutting. Undercutting is sometimes severe, particularly on downstream edges.

Conclusions Based On General Observations

1. Metal loss appears active, and of relatively recent origin.

2. Metal loss is highly localized in an area immediately downstream of sharply defined changes of flow conditions. Two distinctively different changes in flow conditions are header to tube, and the subsequent reduction in flow channel diameter.

3. Patterns of metal loss appear flow oriented, but erratic flow patterns are indicated.

4. Because of obvious contributions from flow conditions, the metal loss is attributed to an operating (steaming), not stand-by(non-steaming) condition.

Specimen Observations - Microfeatures

The following discussion is based on microscopy observations from the three specimen segments indicated by Photo 1.

Photos 4 and 5 show a hole formed in the surface deposit. The hole is one of several small cavities visible in Photo 3. Photo 4 shows flow damage to the deposit coating; a deposit analysis is given below:

X-RAY DIFFRACTION

Major: Ferric Oxide (hematite)
Calcium Phosphate (hydroxyapatite)

High Minor: Magnesium Phosphate

Minor: Magnesium Silicate(serpentine)

Features of the hole, particularly the undercutting and the channel configuration, indicate an erosion process with flow direction from right to left. Curiously, this flow orientation is opposite the direction of bulk fluid flow, indicating the influence of local flow eddies. A stepwise penetration of the deposit structure is evident in Photos 4 and 5. A secondary effect of local turbulence can be seen in the distinctive crystal growth patterns shown in the center of Photo 5. Although it may be that metal loss is associated with the hole, this was not studied. The important observation is that substantial mechanical forces were needed to excavate a relatively thick and protective deposit layer.

Photos 6 through 15 are part of a comprehensive study of specimen B. Specimen B is representative of the banded area downstream from the weld, where surface deposits are notably smooth and metal loss in a clustered pattern of small irregualrly shaped pits.

Photos 5 and 6 feature a highly elongated channel of metal loss. Bulk flow is in the direction of top to bottom in Photo 7, with the weld area just above the area shown in the top of this photo. There are extensive indications of erosion patterns, most notably the undercutting of upstream edges and the pillar like formation which is a classic form of erosional remnant. The taper erosional forces downstream of localized peak turbulence are shown towards the bottom center of Photo 7 and in the five stepped region identified by the numbers 3 to 7. This tapering of erosion coincides with the dissipation of mechanical forces by the surface deposit. In the numbered areas of Photo 7, only areas 1, 2 and 3 are metal/metal oxide surfaces; areas 4, 5, 6 and 7 are different layers of the surface deposit. Two additional areas of deposit damage can be seen in the right side of Photo 7; no metal loss was evident in these areas.

Photos 8 and 9 are close-up views of metal oxide characteristics in the freshly corroded areas shown in Photo 7. They show variations in fissure formation and localized deposition. The localized deposition in Photo 9 is likely the redeposition of by-products of the upstream erosion-corrosion process.

Photos 10 and 11 show additional close-up views of features near the pillar. The pillar is the result of a flow stagnation zone and serves to illustrate the pecularities of localized turbulence.

Photos 12 and 13 show details of metal loss on the side of the channel. From the vantage point of Photo 12, the bulk flow appears to be from top to bottom. Thus, there is evidence of bidirectional flow; axially as shown by Photo 7; and logitudinally as shown by Photo 12. Further

evidence of bidirectional flow is the overall L-shaped area of metal loss, as seen in Photo 6. A similar character is evident in the S-shaped deposit damage shown in the right side of Photo 7.

Photo 13 is a view of the top edge of the erosion channel in Photo 12. The deposit metal interface shows an even radius of curvature, thus indicating flow effects. The iron oxide surface on the side wall of the channel shows many fissures and pock marks, both of which I judge to be the results of mechanical damage due to cavitation. The pocks are clearly in a area of reduced pressure (a trailing edge) based on the above observations of bulk flow. Since the expected flow is a steam/water mixture it would follow that any abrupt pressure drop could lead to a rapid sequence of bubble nucleation, and bubble collapse.

Photos 14 and 15 show close-up views of a pock in the floor of erosion channel shown in Photo 7. Although similar to other areas of freshly eroded areas (i.e., Photos 8, 9, 11, 13). Photo 14 coincidentally shows the remnants of grain boundaries. Grain boundaries are more resistant to mechanical deformation than is the grain interior. Photo 15 is a close-up view of the classical 120° angles formed by the junction of three grains.

Photos 16 and 17 provide another view of deposit damage adjacent to an area of metal loss. The pocked area shown in Photo 16 is barely evident in Photo 6 (lower left of center, in axial alignment with pillar). As with deposit damage in Photo 4 and 6, it is clear that a substantial thickness of deposit must be removed before metal damage can begin.

Photos 18 and 19 show the upstream and downstream ends of an erosion channel in Specimen C. The undercut shelf on the upstream side (Photo 18), and the gradual tapering of metal loss combined with redeposition of material (Photo 19) are typical features of the erosion-corrosion process.

Photos 20 and 21 show the metal/metal oxide interface of non-eroded and eroded surfaces, respectively. The "saw-tooth" periodicity of metal loss evident in Photo 21 is highly indicative of severe turbulence and may be associated with cavitation.

Erosion-Corrosion - General Perspective

Erosion-Corrosion can be distinguished from pure erosion, and from cavitation. When dealing with metal loss in aqueous systems it is probably impossible for solution chemistry to not play some role. Erosion-corrosion is flow assisted corrosion, typically associated with severe fluid disturbance at the metal surface. Ideally, the contribution of erosion forces can be differentiated based on vertical, oblique or tangential incidence of a flow. The corrosive

forces are essentially surface dissolution mechanisms, no different than those normally present except that erosive wear prevents the formation of normally protective oxide coatings.

Erosion-corrosion in steam plants is an old problem, particularly for the designers of wet steam piping and turbines. The problem is frequently encountered in some nuclear steam generators, but uncommon in conventional boilers.

Power plant experience with erosion-corrosion of carbon steel indicates:

- An incubation period (days) is required. Once the process starts, metal loss can be severe.

- Maximum damage, statistically speaking, occurs in the temperature range of 140-180°C (900 psi boiler, approximately 280°C).

- Carbon steel requires velocities of about 5-10 M/sec.

- Variations in mass transfer coefficients reach a maximum at about two pipe diameters downstream of an orifice.

- pH less than 9.0 to 9.2.

- Dissolved oxygen greater than several hundred ppb.

Overall Situation at Ivorydale No. 4

Because the overall situation is so ordinary (traditional boiler, standard water chemistry, etc.), I am inclined to look for something strikingly unique to explain the problem. Because the boiler is twenty years old and the 1983 corrosion rate measurements show up to 11 mils/year, the problem of metal loss is implied to have a recent origin.

If we can find a way to explain the incubation period, we have an easy time explaining subsequent metal loss. Once erosion channels are established, they tend to be self-perpetrating because of the localized flow disturbances they cause. Once started, metal loss can be rapid and a relatively short interval of time can account for much metal lost. By this rationale, however, the problem could date back twenty years. This would assume severe flow conditions on a sharply intermittent basis. Mechanical forces are the main culprit and further review is needed to decide how to best explain this facet of the problem.

Based on observations elsewhere , we should be suspicious of chemical conditions that would aggravate the surface corrosion process, specifically low temperature, low pH, and/or high dissolved oxygen.

From the information available to me, I would judge hydraulic conditions resulting from recent operating practices with load reduction, and extended standby (weekends) to be a primary cause of metal loss.

Recommendations

1. Continue hydrogen studies. Unfortunately, circulation problems associated with low load, or chemistry problems associated with standby will be most difficult to diagnose in low load, or no load operations.

2. A neutralizing amine with a high distribution ratio, favoring pH elevation of the vapor phase should be considered.

3. Hydrazine should be considered because of its multiple role as a volatile amine, oxygen scavenger and passivating agent.

4. If strategically located, corrosion test coupons can be installed, they would aid in better defining the mechanism and rate of metal loss. They would also serve as ready indication of when the metal loss conditions due to erosion-corrosion no longer exist.

5. I concur with recommendations previously made by Jim Stephens (use of antifoam; MgO type fireside additives) if metal loss can be associated with steaming conditions rather than standby.

F. H. Seels

FHS/p
Attachments

cc: S. T. Costa
J. R. Stephens
W. L. Trace
J. L. Walker
J. D. Zupanovich

MEMO

CALGON
SUBSIDIARY OF MERCK & CO., INC.

TO K.A. Arbuckle

FROM J.R. Stephens

SUBJECT P&G, IVORYDALE PLANT, CINCINNATI, OHIO
NO. 4 BOILER INSPECTION

DATE 10-3-83

On Monday, September 26, Ed Lederach, Ken Arbuckle and I inspected the No. 4 boiler. We concentrated on the top water wall headers and cross-over tubes. We inspected these areas with the P&G fiberoptics. The following observations were noted.

1. There were black areas about the size of half dollars in the top of the water wall header directly above the water wall generating tubes. The black areas closer to the steam down were rougher and were the result of possible impingement attacked. These areas appeared to be blasted with steam and water mixtures at extremely high velocities. This is an indication of an extremely high heat absorption in the water wall tube.

2. Very little metal loss was observed in the water wall tubes as they entered the header - the tube diameter is reduced as they enter the header.

3. However, as the steam and water mixture left the water wall header into the cross-over delivery tubes to the steam drum, the tube diameter through the header and about 3 inches inside is reduced about ¼ inch. In the last inch and one-half area just before the weld, a very peculiar phenomenon of high metal loss occurred. In some tubes, the metal loss is 360° around the tube (almost exclusively in the smaller diameter tube.) There was very little evidence of metal loss in the larger diameter cross-over tubes. This indicates to me that the metal loss was a function of the tube geometry and velocity. The tubes closer to the steam drums appeared to contain more metal loss. Non-destructive testing indicated one to eleven mils metal loss since the last inspection in April, evidencing metal loss is still occurring.

4. This peculiar type of attack had undercutting in the pits. Because of boiler water chemistry, acid attack was eliminated because of 5-10 ml B-Reading constantly in the boiler water. In my opinion, if acid was involved there would also be attack on the larger diameter (½" ID bigger) tubes also. Because of boiler water chemistries and the fact that the boiler has not been acid cleaned in 10 years, I do not believe that this attack could be related to acid.

   Since chelating agents have not been used, the attack cannot be caused by chelants.

5. By process of elimination, I have deduced that the possible cause of attack is cavitation. Even though we have not seen cavitation in a boiler before, I believe that this is the only possible explanation of the attack. Cavitation attack could result from the collapse of steam bubbles as the steam-water mixture leave the water wall header in the smaller diameter tube (cavitation resulting from a pressure increase and

rapid collapse of steam bubbles). Remember that there is an extremely unusual high velocity problem evidenced by the etched spots in the top of the header.

Even though it is hard to believe, the only possible cause of this problem to me is cavitation.

6. The operation of this boiler was base loaded until 5 years ago. Since then, No. 4 boiler is the only boiler used in the summer months and is subject to load swings. The weekend load is usually 125-150,000 lbs. per hour compared to an average workday load of 275-300,000 lbs. per hour. I believe that these load changes have played a part in the present problem.

7. Also the fuel treatments and firing patterns should be examined more closely.

As a possible solution to this type of attack, I recommend the following:

1. Double the C-1 antifoam feed rate to give a better rinsing of the water wall tubes with the steam water mixture. I'm not sure that this will help, but it is not expensive and I think, has a reasonable chance of helping reduce the metal loss in the cross-over tubes.

2. There definitely appears to be excessive heat absorption in the water wall tubes. In order to reduce this, I recommend a magnesium type fuel conditioner be considered. History has proven that this type of fuel conditioner has reduced the radiant heat absorption in the water wall tubes and has increased superheat as high as 30°F without changing firing patterns.

Should you have any questions or comments, do not hesitate to contact me.

J.R. Stephens
BW

J.R. Stephens

JRS/baw

cc: S.T. Costa
E.K. Lederach
WMD File

PHOTO INDEX

Nos. 1-3 Gross Specimen, Macrophoto

No. 4, 5 From Specimen A in Photo 1, SEM

Nos. 6-17 From Specimen B in Photo 1, SEM

Nos. 18-21 From Segment C in Photo 1, Metallograph

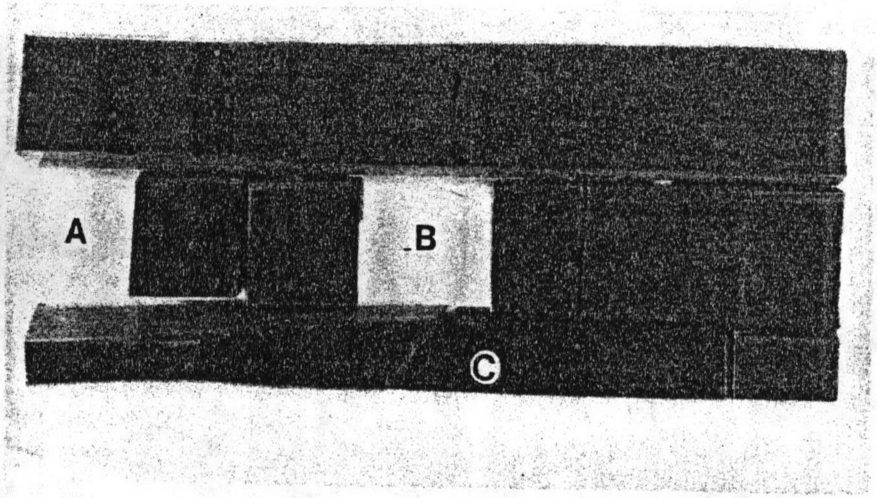


PHOTO 1 Specimen Showing Sampling Cuts

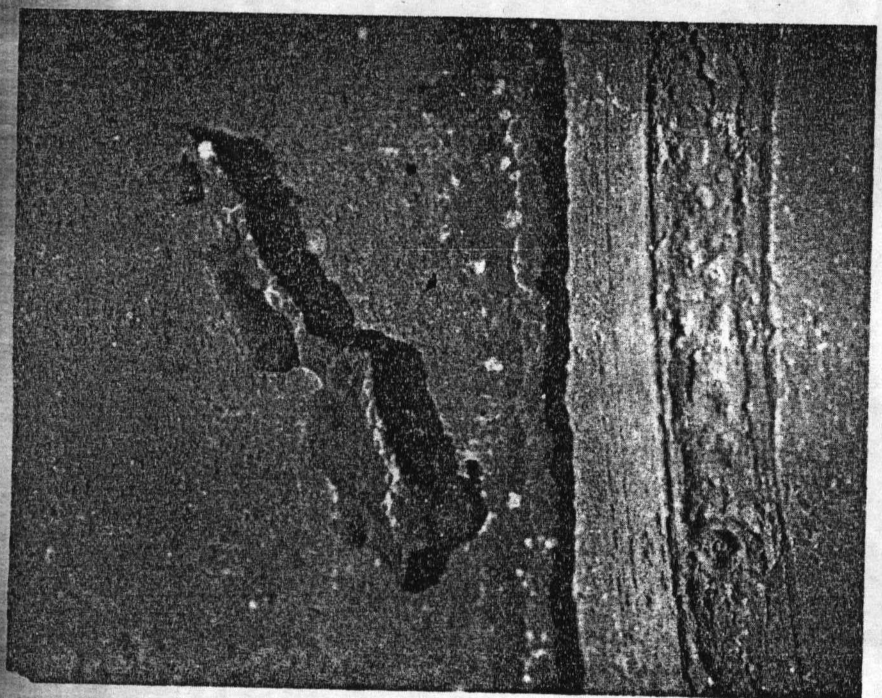


PHOTO 2 Specimen As Received, Area Upstream From Weld

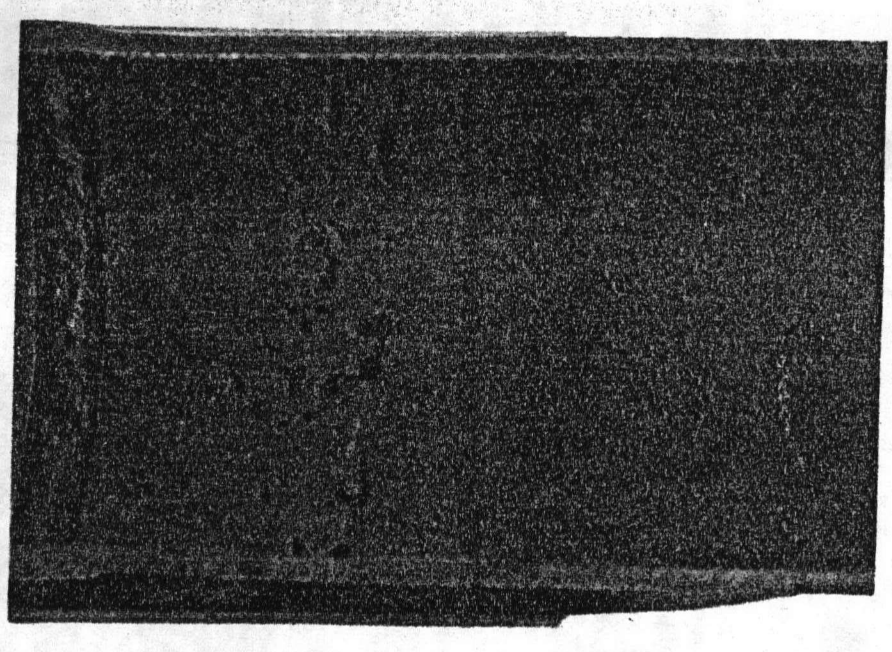


PHOTO 3 Specimen As Received, Area Downstream From Weld

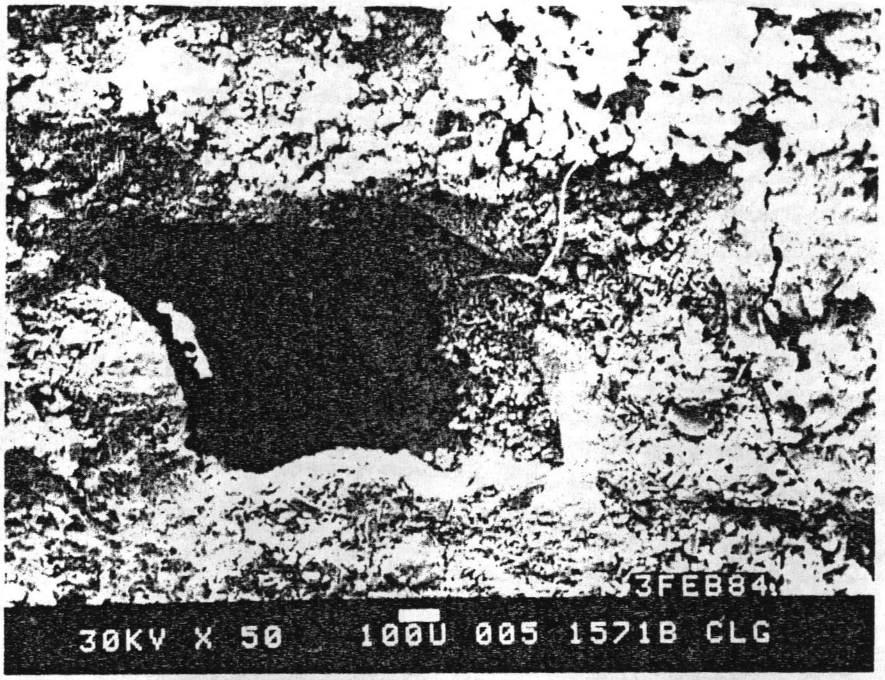


PHOTO 4 Details of Cavity Shown in Lower Left Of Photo 2

PHOTO 5 Closeup of Photo 4, Showing Stepwise Effect of Turbulence On Crystal Growth

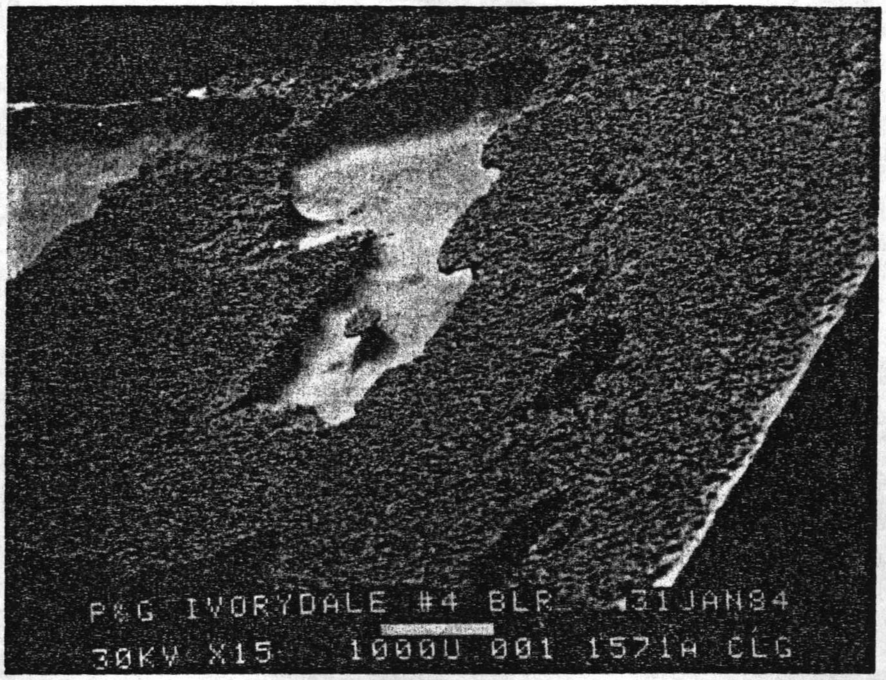


PHOTO 6 Segment B in Photo 1,
Oblique View Showing Undercut Features

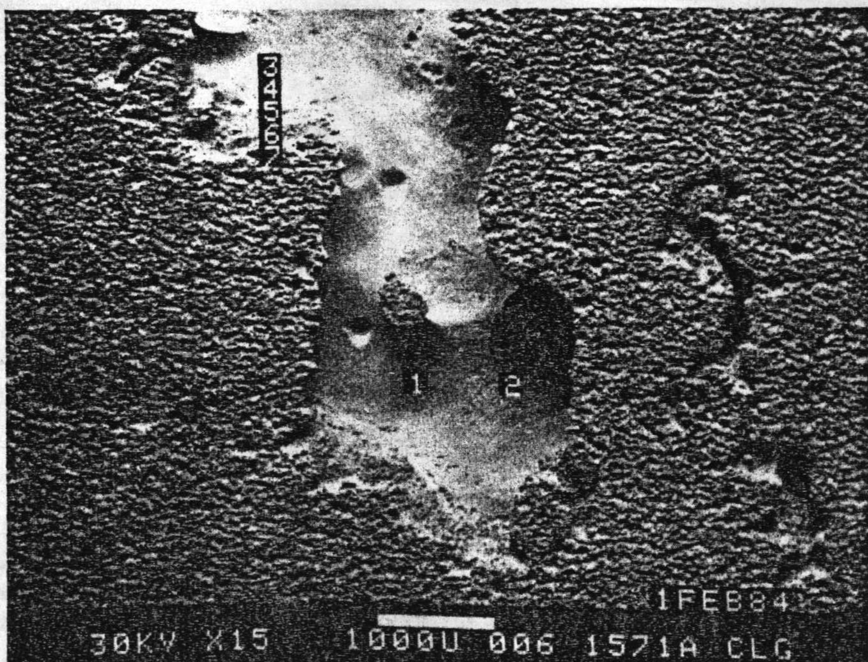


PHOTO 7 Top View of Center Area in Photo 6

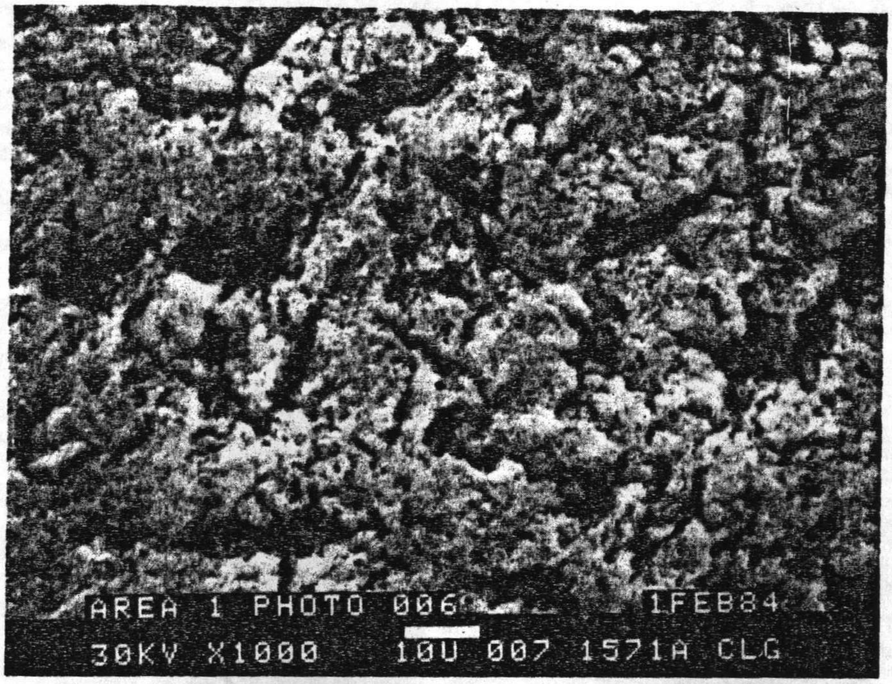


PHOTO 8 Closeup Of Area 1 In Photo 7
Note Fissures In Oxide Layer

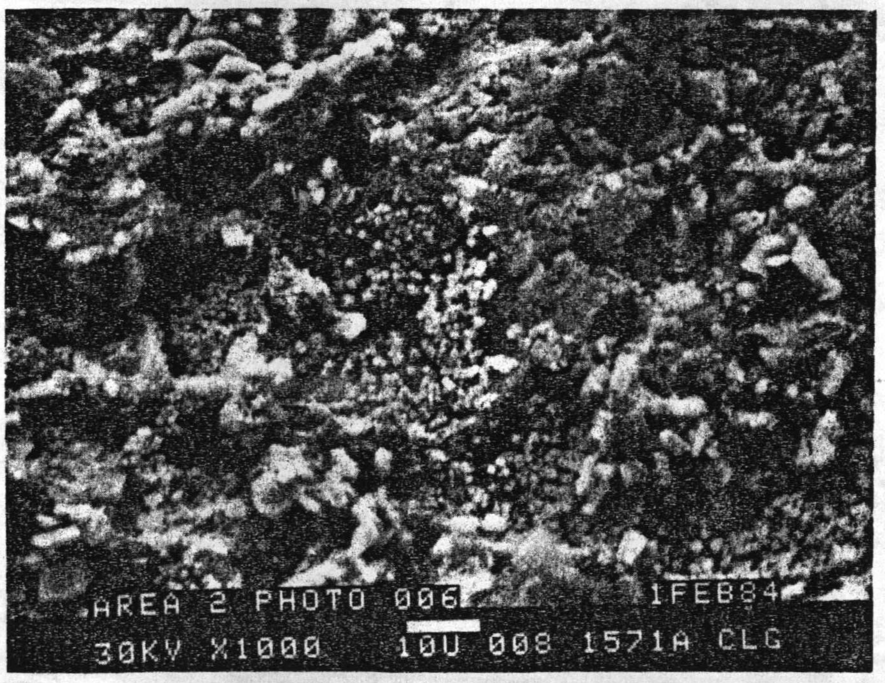


PHOTO 9 Closeup Of Area In Photo 7
Note Recent Deposition (Crystal Growth)

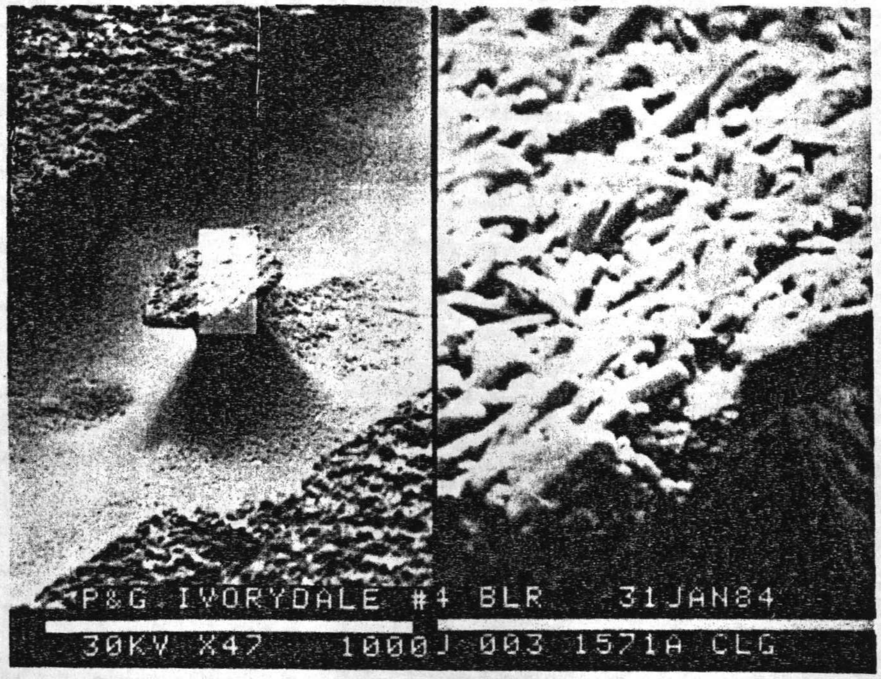


PHOTO 10 Closeups of Pillar Shown in Photos 6 and 7

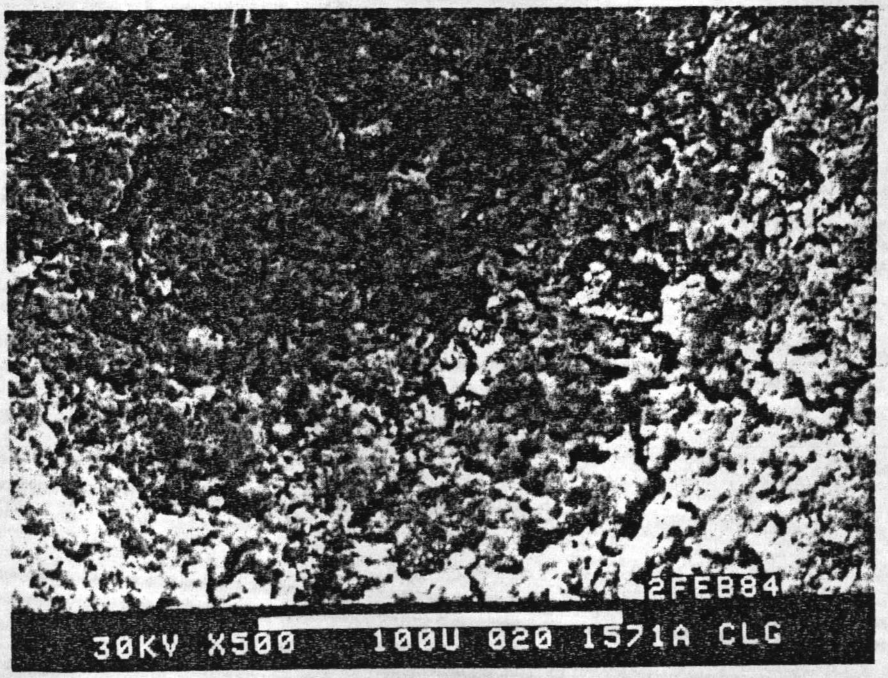


PHOTO 11 Closeup Of Pock At Left of Pillar

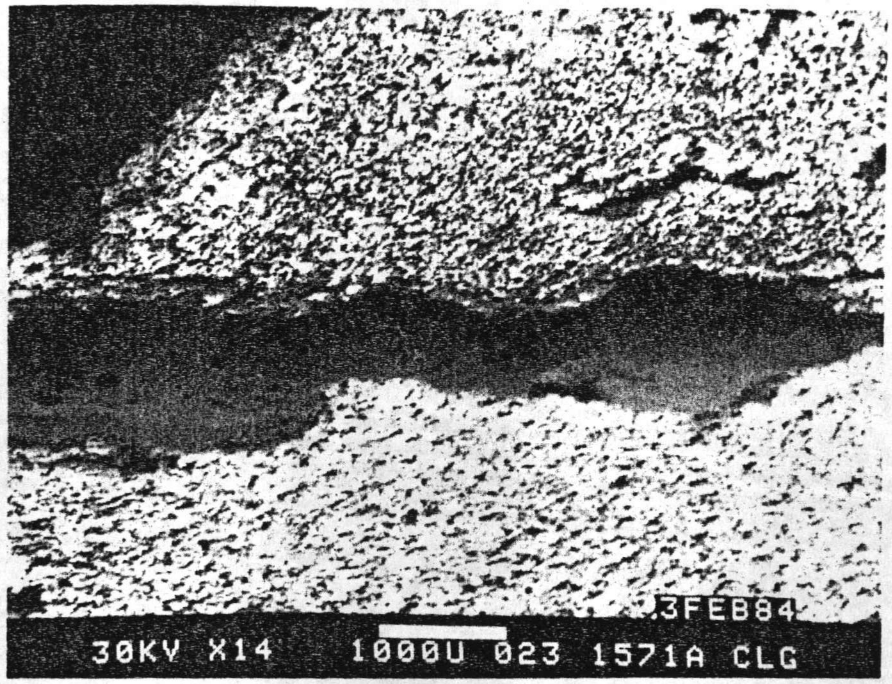


PHOTO 12 View Showing Secondary Pocks In Side Of Eroded Channel, Oblique View of Area in Photo 7

PHOTO 13 Closeup Of Photo 12 Showing Details of Pocks and the Interface Between Tube Metal and Surface Deposits

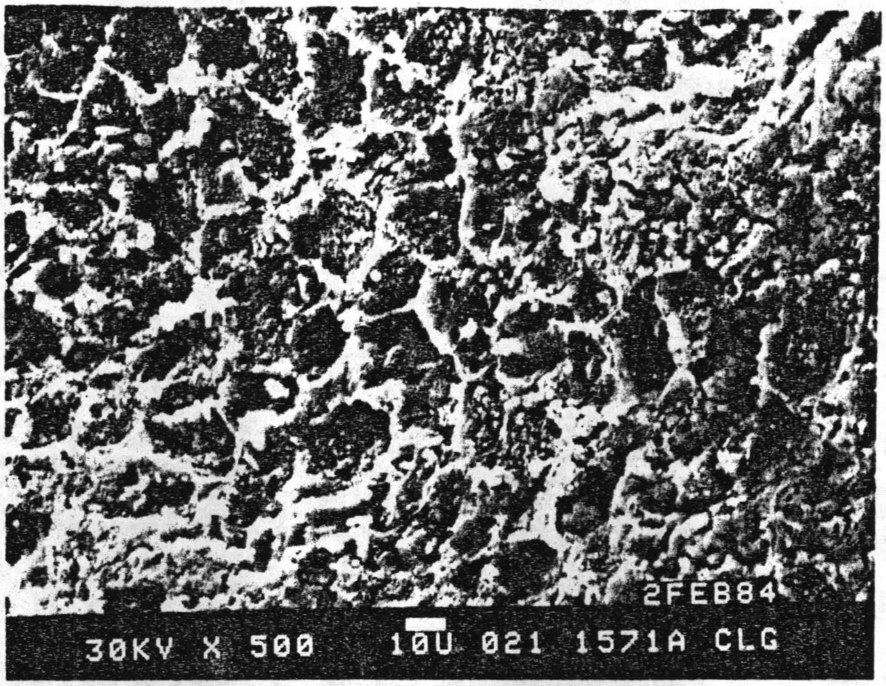


PHOTO 14 Closeup Of Secondary Poek In Floor of Primary Erosion Channel; Area Shown At Top, Center of Photo 7

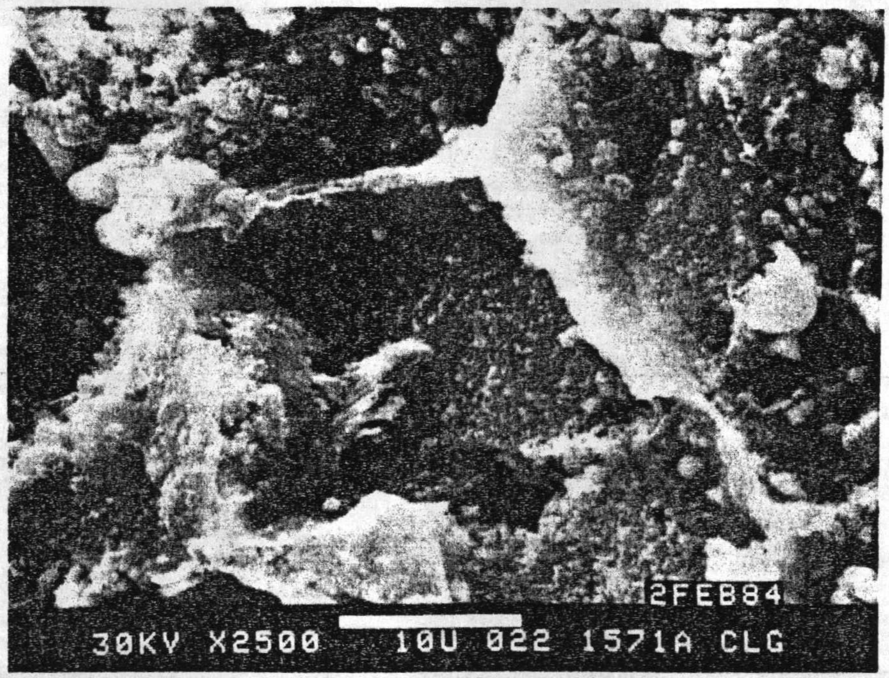


PHOTO 15 Closeup Of Photo 15 Showing Remnants Of Comparatively Hard Grain Boundaries

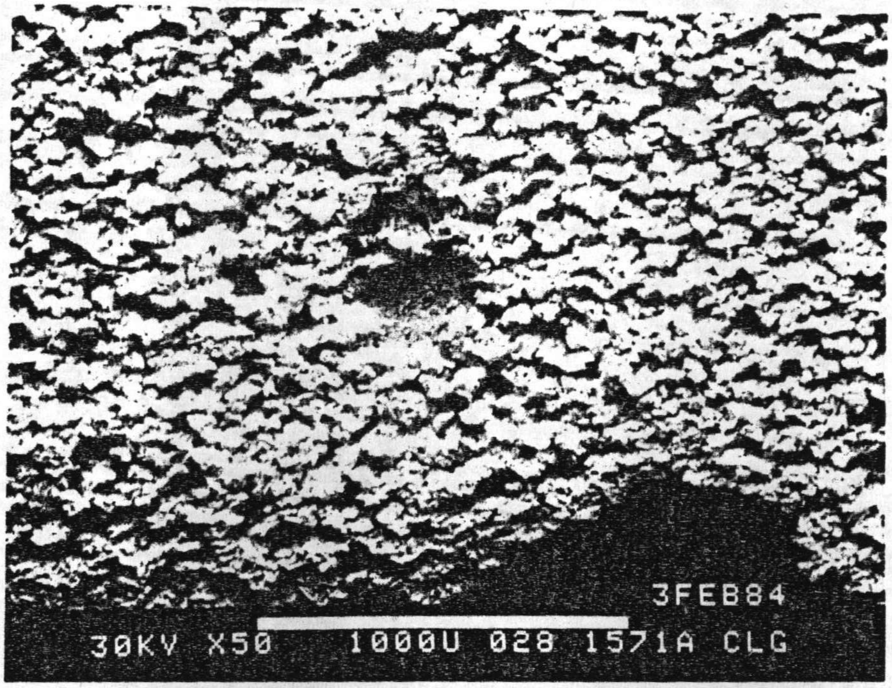


PHOTO 16 Closeup Of Cavitation Damage To Surface Deposit, Area Shown In Photo 6 Below And Left of Center

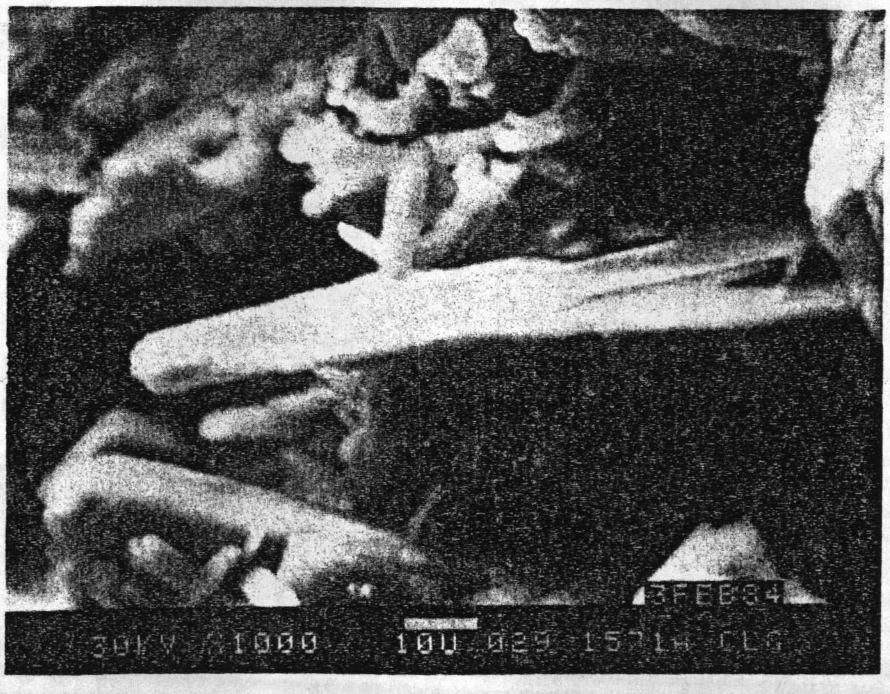


PHOTO 17 Closeup Of Photo 16 Showing Calcium Phosphate Needles

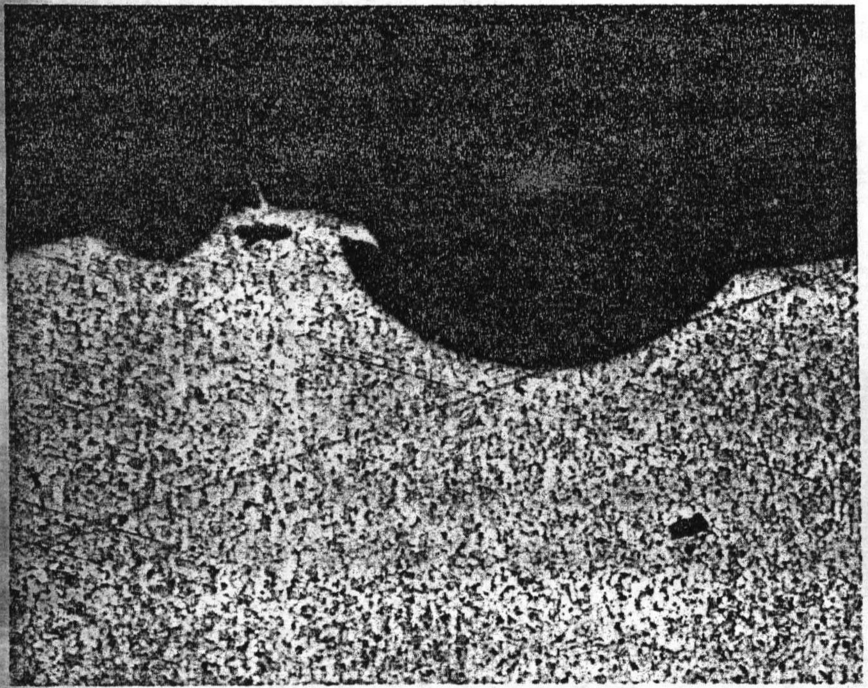


PHOTO 18 Segment C Polished Cross Section, Nital Etch 50X

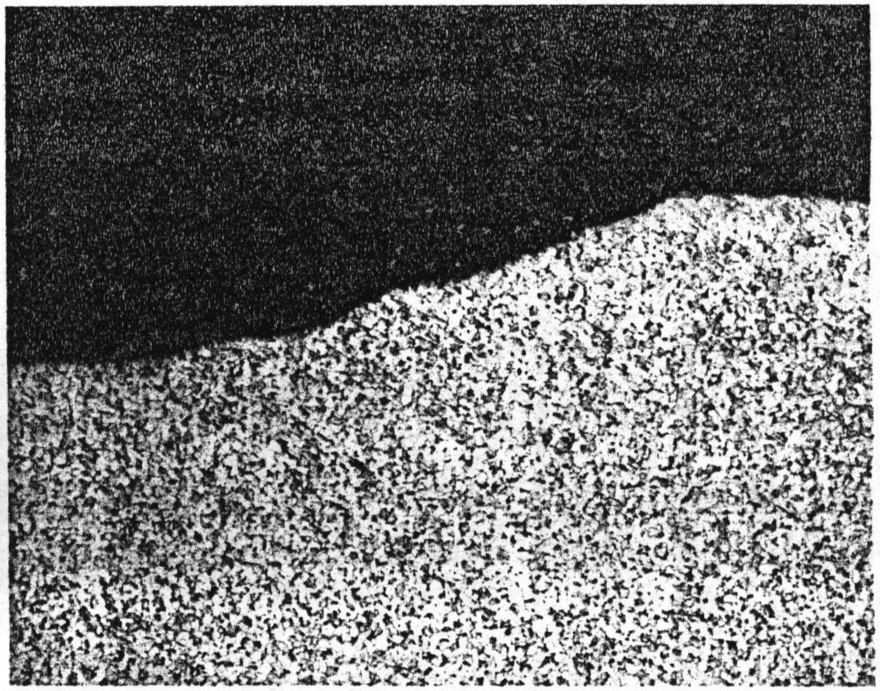


PHOTO 19 Termination Of Erosion Channel Shown In Photo 21 50X

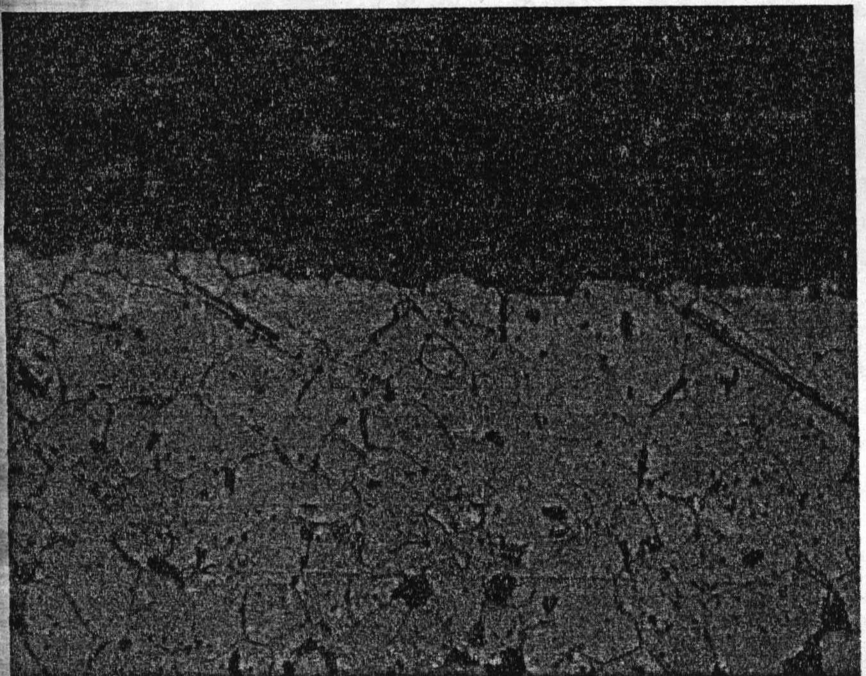


PHOTO 20 500X Closeup Of Non-Eroded Metal Surface

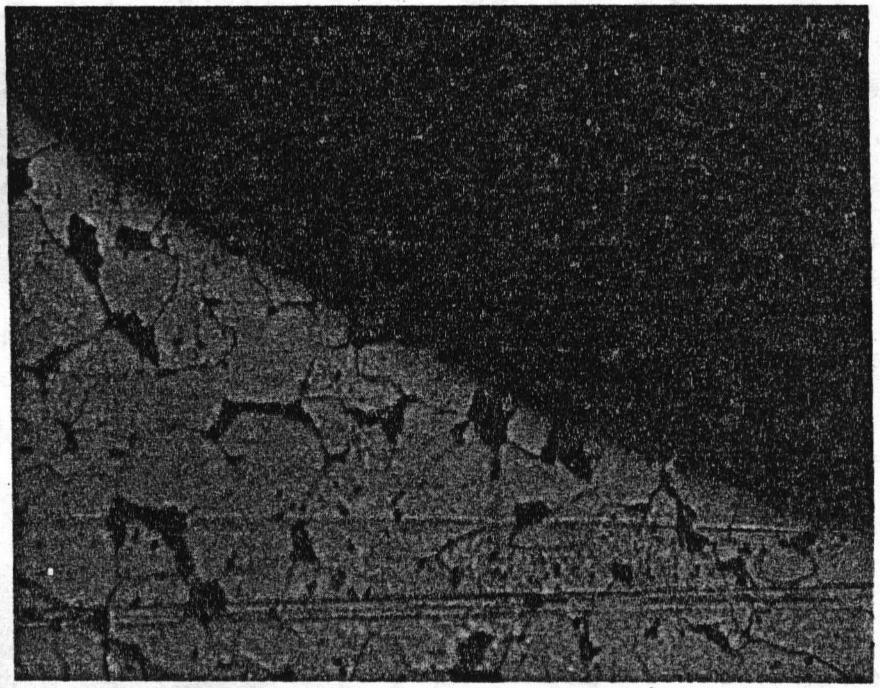


PHOTO 21 500X Closeup Of Eroded Metal Surface

CALGON CORPORATION

SUBSIDIARY OF MERCK & CO., INC.

INTEROFFICE CORRESPONDENCE
CALGON CORPORATION

Paper Chemicals

DATE: June 1, 1977

TO: W. E. Pfeiffer

FROM: R. E. Elliott

SUBJECT: SOUTHLAND PAPER - HOUSTON, TX
FAILURE OF STAINLESS STEEL COUCH ROLL

Sorry it took me so long to reply to your speed letter, just to tell you that we don't know. The 413 stainless steel must be a very uncommon specialty steel. Our Information Center checked with half a dozen places in the Pittsburgh area and in Washington, DC and could come up with no information on 413. The chemical analyses attached to your speed letter fits 316 stainless, except that the silica is 1.1% instead of a maximum 0.75%.

Generally speaking, the ferritic stainless steels are not subject to chloride stress corrosion and, in general, the 400 series of stainless are ferritic. Again, in general, 400 series stainlesses do not contain nickel with the exception of a few that have one or two percent nickel in them, nothing like the 13.6% nickel in the analyses you sent in.

Of the austenitic stainless steel (the 300 series), 316 is one of the more resistant to chloride attack. There is also information which states that chloride cracking is usually only above 160°F. I think perhaps something might be learned from an analyses of the failed metal by an expert in stainless steel. I would suggest Dr. Harold Jack Snyder as an expert that Southland might contact. Dr. Snyder's phone number is 504/283-1009 and his address is 833 Jewel Street, New Orleans, LA 70124.

Ed

R. E. Elliott

kld

cc: R. S. Byron
R. A. Kass
J. F. Turner
H. K. Kolavick

1. DETACH YELLOW COPY.

INSTRUCTIONS TO SENDER
2. SEND WHITE AND PINK PARTS WITH CARBON TO PERSON ADDRESSED.

INSTRUCTIONS TO RECIPIENT
1. WRITE REPLY AT BOTTOM.
2. DETACH STUB, RETAIN WHITE COPY AND RETURN PINK COPY TO SENDER.

To: ED ELLIOT
WATER MANAGEMENT
PITTSBURGH
CC R.A. KASS, FRED TURNER

1

From: WEPfeiffer
Calgon Corporation
Water Management Division
4800 West 34th St., Suite B - 8
Phone: 681 - 5426
Houston, Texas 77092

CALGON CORPORATION
SUBSIDIARY OF MERCK & CO., INC.

SUBJECT SOUTHLAND PAPER HOUSTON; FAILURE OF STAINLESS STEEL COUCH ROLL

DATE 5/12/77

MESSAGE

ED,

FRED TURNER + I CALLED ON THIS MILL + ONE OF THEIR MANY PROBLEMS CONCERNS ATTACK ON THEIR STAINLESS STEEL COUCH ROLL ON THEIR NEWSPRINT MACHINE SUPPOSEDLY BY CHLORIDE. THEY HAD A FAILURE LAST JULY + AGAIN LAST WEEK. THE PRODUCTION LOSS FROM THE LAST FAILURE COST THEM $260,000.

THE COUCH ROLL IS AT LEAST 3 FEET IN DIAMETER + 300" LONG. THE MACHINE AVERAGES 3000 - 3100 ft/min of NEWSPRINT. AN ANALYSIS OF THE STAINLESS IS ATTACHED. I HAVE TWO QUESTIONS:

1. IS THIS THE RIGHT KIND OF STAINLESS FOR FAIRLY HIGH CHLORIDE CONCENTRATIONS?

2. DO YOU OR ROGER KNOW OF ANY TYPE OF INHIBITOR THAT MIGHT HELP?

SIGNED Bill

Reply Message ATTENTION OF

DATE OF REPLY

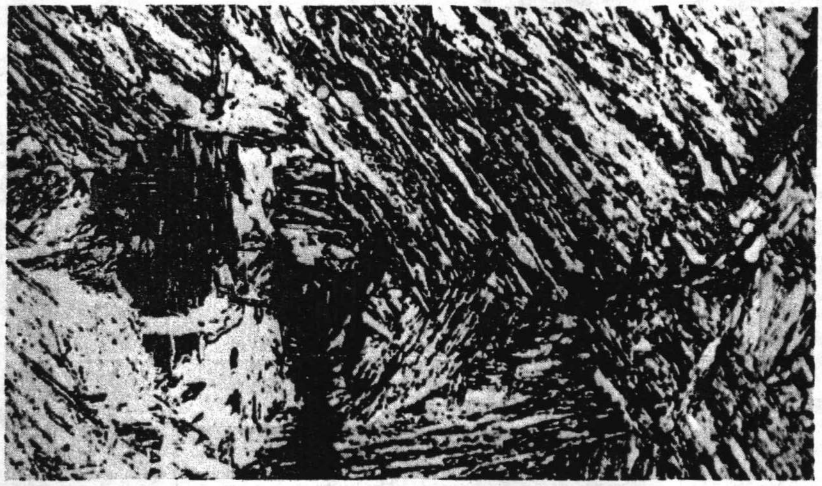


Figure 5 Martensite

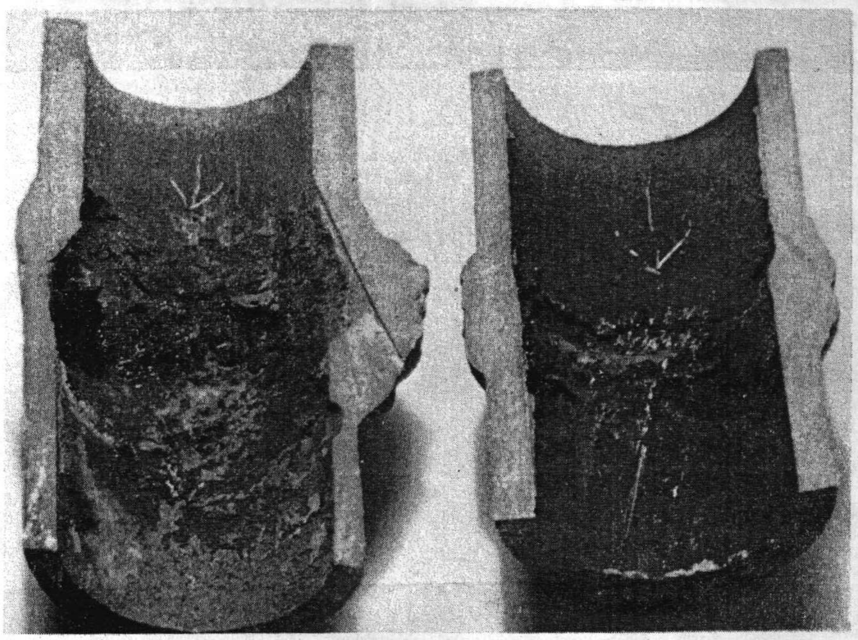


Figure 6
Caustic
Attack
(Field Weld)

Figure 8
Hydrogen
Embrittlement

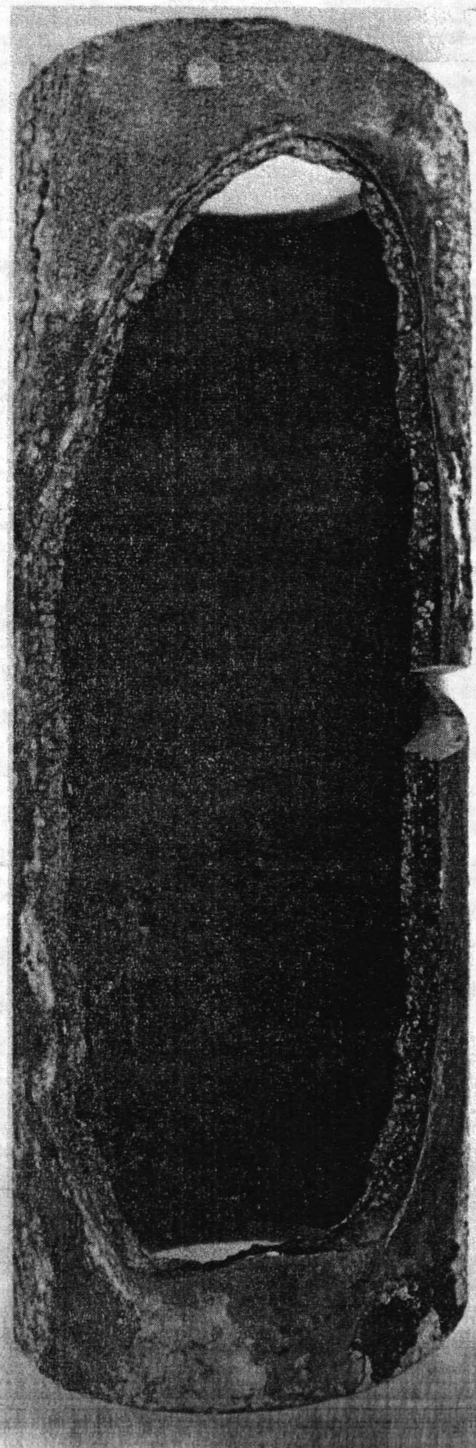
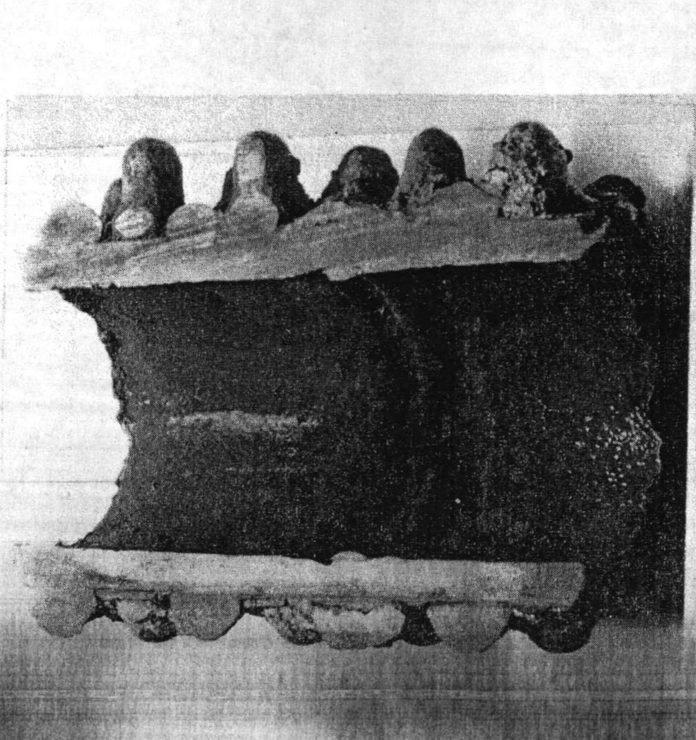


Figure 7
Caustic
Attack
(Chill Ring)



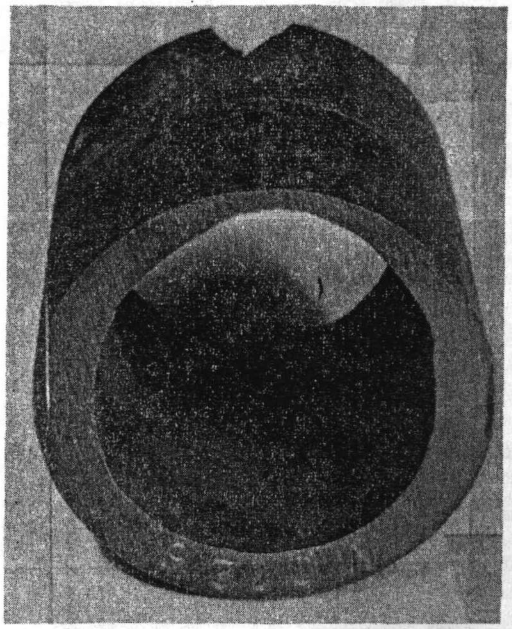


Figure 9
Caustic Attack
(Steam Blanket)

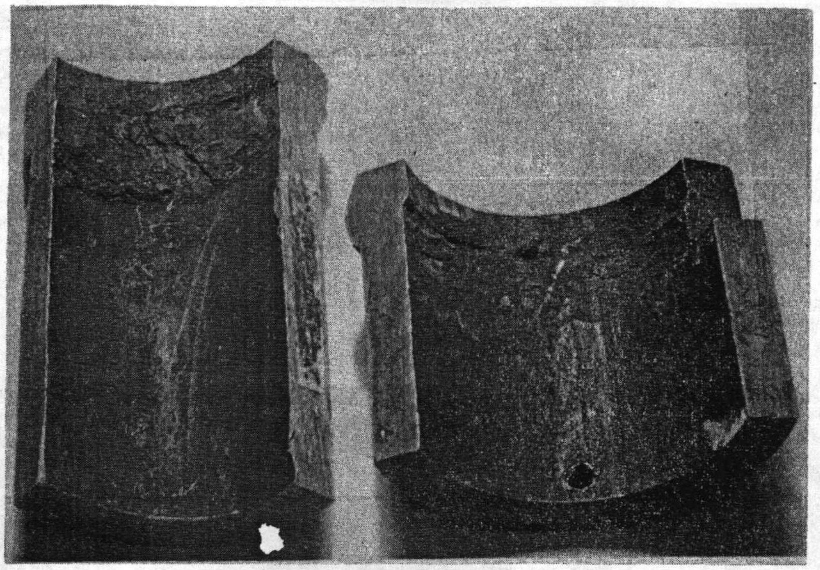


Figure 10
Captive Alkalinity (Left)
Free Caustic (Right)

Figure 11
Quench Cracking

Figure 12
Localized Stress

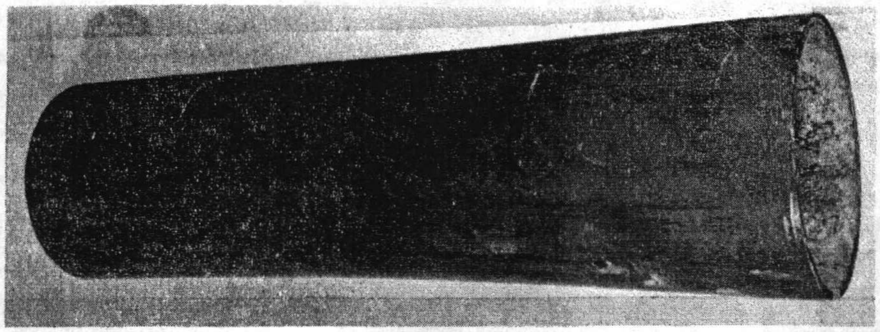


Figure 13 Creep Distortion

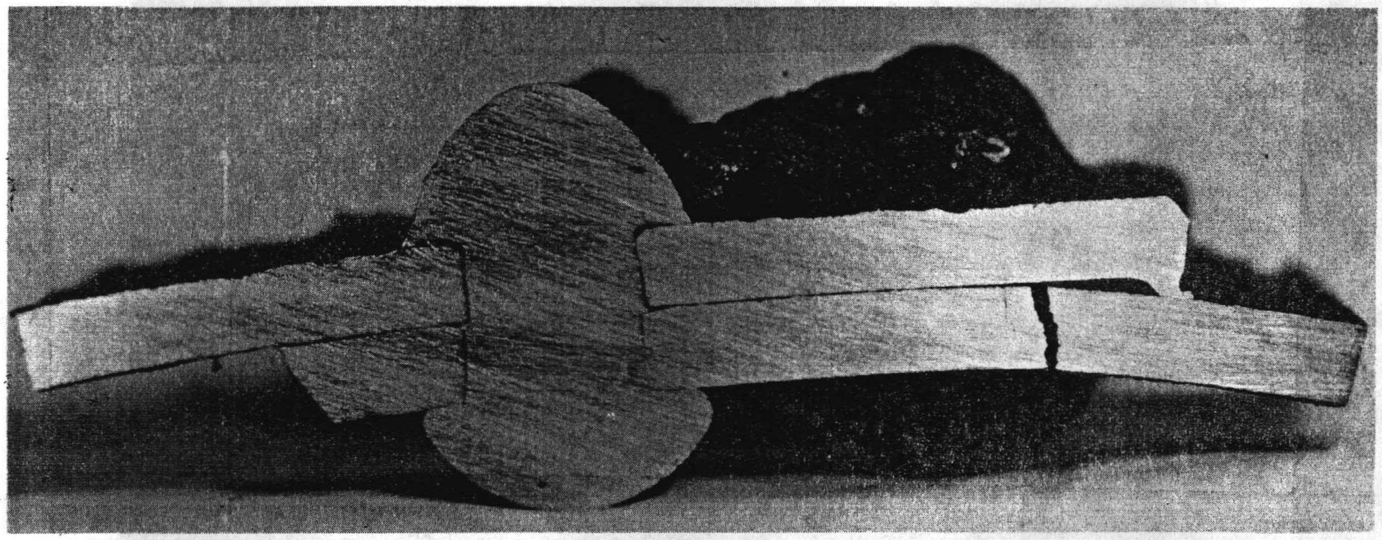


Figure 14 Caustic Embrittlement

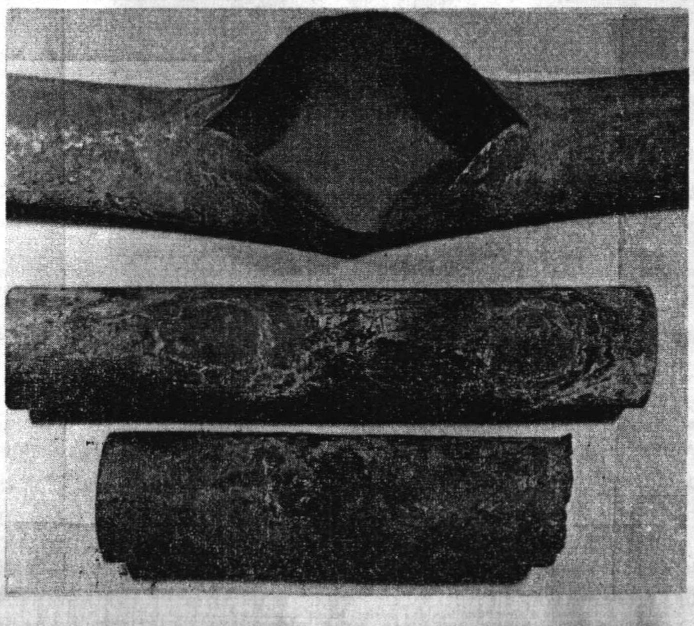


Figure 15 Overheating

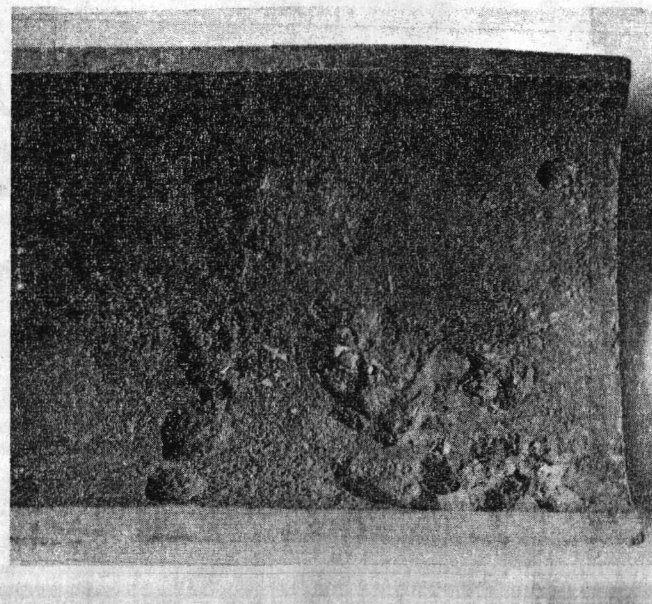


Figure 16 Dissolved Oxygen Attack

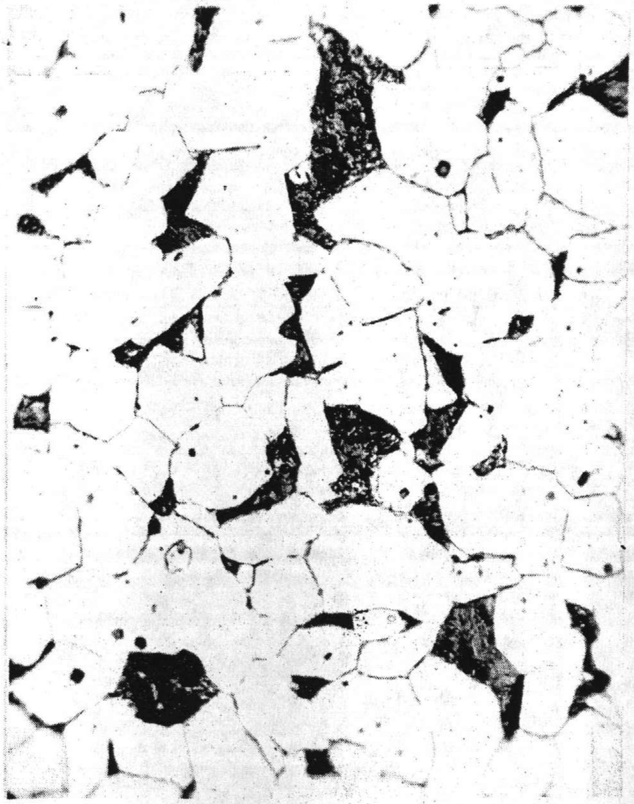


Figure 1
Normal Structure
Low Carbon Steel

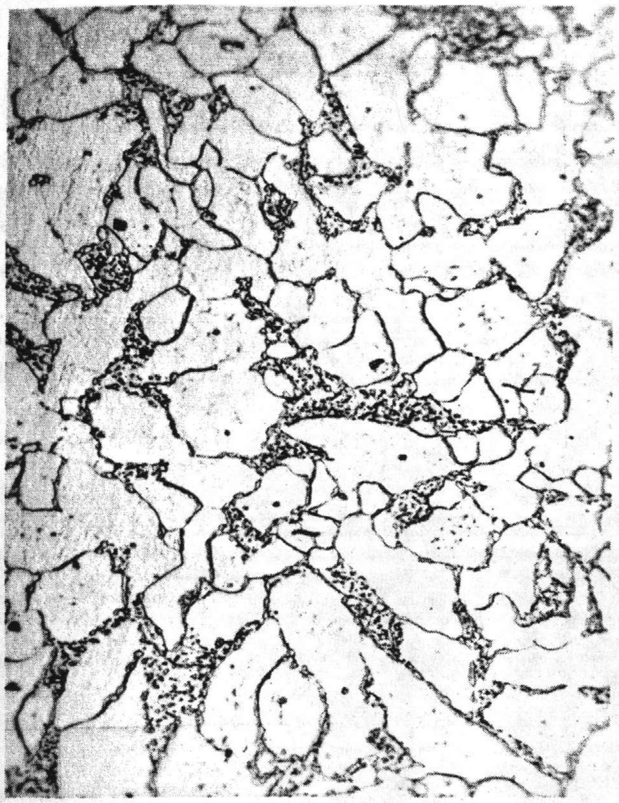


Figure 2
Spheroidization

Figure 3
Decarburization

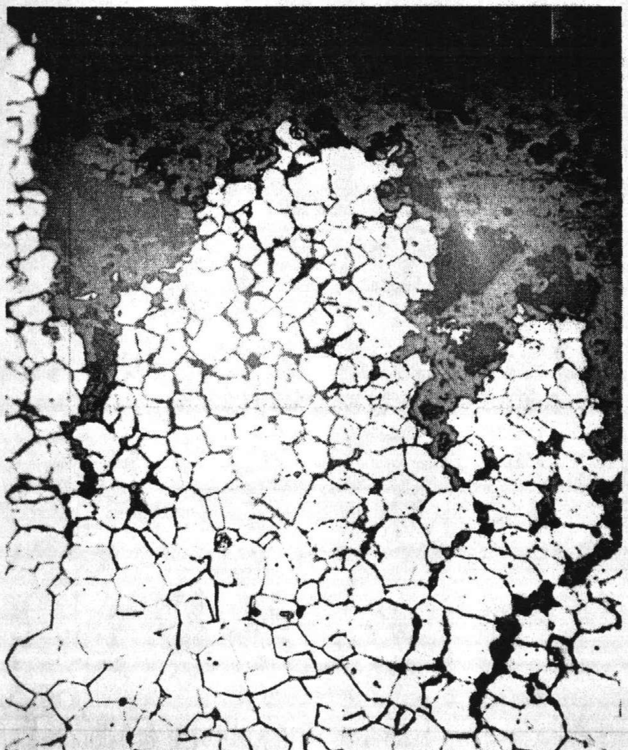


Figure 4
Decarburization & Inter Granular
Oxide Penetration

REC

METHOD FOR DETERMINING AMOUNT OF DEPOSIT IN BOILER TUBES

1. Remove one or more 18-24 in. long tube specimen(s) from critical area(s) of boiler. (e.g. high heat input zone, inclined tube in furnace, etc.)

2. Carefully remove any loose material from external surface of tube by wire brushing or other suitable means that will not dislodge internal deposits.

3. Cut a 6 in. section from center of tube specimen, using power hacksaw or other means of making a "dry" cut.

4. Split the 6 in. section longitudinally into "hot side" and "cold side" sections using power hacksaw or other suitable means.

5. Carefully scrape the internal deposit from the two halves of the tube section and weigh the combined deposit to the nearest 0.1 gram. (Note: In some cases it may be desirable to weigh separately the deposit from the "hot side" and "cold side" sections.)

6. Determine the average amount of deposit in the tube section:

$$\text{Grams/ft.}^2\text{-combined} = \frac{(\text{Grams combined deposit})\ (144)}{(3.14)\ (\text{tube ID, in.})\ (\text{Tube section length, in.})}$$

7. If an estimation of average amount of deposit on hot side of tube is desired, determine as follows:

$$\text{Grams/ft.}^2\text{-"hot side"} = \frac{(2)\ (\text{Grams "hot side" deposit})\ (\text{Grams/ft.}^2\text{-combined})}{(\text{Grams combined deposit})}$$

Ed

CALGON CORPORATION

SUBSIDIARY OF MERCK & CO., INC.

WATER MANAGEMENT DIVISION CALGON CORPORATION CALGON CENTER BOX 1346 PITTSBURGH, PA. 15230 (412) 923-2345

PROCEDURE FOR THE MACRO ETCH OF BOILER TUBE SPECIMENS
(For Detection of Hydrogen Damage)

1. Polish surface to be inspected to a smooth finish. Use a final abrasive of 240 to 320 grit.

2. Heat a solution of 1:1 concentrated Hydrochloric Acid:Water (18% HCl) to 150°F.

3. Soak the specimen in the hot hydrochloric acid for 10 minutes, maintaining the temperature at 150°F.

4. Remove specimen from hot acid and flush with water.

5. Promptly immerse specimen in alcohol, or acetone, and soak briefly with mild agitation.

6. Dry specimen and inspect. Black, darkened areas indicate the presence of macro fissures caused by hydrogen damage.

NOTES

a. For ease of handling, small specimens are preferred. A 1/4 inch length of boiler tube is suggested. Larger specimens are more likely to break glassware if dropped and this is a significant hazard if using a glass beaker for the etching solution.

b. Inferior, but usually acceptable, results can be obtained by polishing with 60 grit abrasive.

c. Large amounts of deposits may prevent a successful macro etch. On such an occasion the first etching attempt serves only to chemically clean the specimen. The specimen must be repolished and etched a second time. A small specimen is less likely to dirty the etching solution.

d. Temperature should be maintained ±3°F. Insertion of the sample will tend to lower the temperature of the etching solution. This is an increasing problem with increasing sample size.

e. The use of acetone or alcohol is to promote rapid drying of the specimen and prevent after-rusting. If these solvents are not readily available, a passivating solution such as 1% sodium carbonate or trisodium phosphate may be used.

① Hall Staff
REE TAM
OMH DEN
LED ← Dww
EOP MR
JES
② Zator
GH RS SS
③ Hall File

CC: Mr. Hunter
CC: Hall Labs
CC: Mr. Thompson
CC: Mr. Roland
CC: Dr. Liddell
CC: Dr. Hatch

October 16, 1962

Mr. J. DiGiacinto

BIRMINGHAM OFFICE

Union Carbide Nuclear
Oak Ridge, Tennessee
Aluminum Corrosion in HFIR System

Dear Joe:

The aluminum surface often is a better place to look for heavy metals suspected responsible for pitting than the water. If heavy metals are involved we should expect to find them on or closely adjacent to the pits. They will be on the metal surface rather than in the corrosion products.

The most satisfactory means we have found for extraction and identification of such metals is an "Electrographic" method. This consists in making the surface under examination an anode and pulling the metal contaminants through filter paper impregnated with colorimetric reagents for the metals in question. A description of the method is contained in F. Feigl's "Spot Tests" Vol. 1, page 428, 4th Edition (1954) Elsevier Publishing Co., New York. A moist filter paper impregnated with a suitable colorimetric reagent is sandwiched between moistened HCl impregnated filter papers. This "sandwich" is then placed on the surface to be examined, an aluminum cathode placed on the other side of the "sandwich" and a 1-1/2 volt dry cell connected across the two plates (being sure that the polarity is right). The metal contaminent is pulled off the test surface and migrates towards the cathode. When it hits the reagent paper it reacts and forms a characteristic colored stain. For example, nickle will give a pink or red stain on dimethylglyoxime impregnated paper; copper a reddish-brown stain on ferrous oxide impregnated paper, etc.

e1

Mercury provides additional complications as it tends to diffuse into the aluminum. Hence, the best procedures for mercury involve heating the specimen to volatilize the mercury and its detection in the gas phase. Probably the most sensitive means for the latter is its adsorption at 2536A. It also can be detected by a red to orange coloration of cuprous iodide impregnated filter paper placed in the gas stream. One of the difficulties with mercury is the ease with which it can volatilize from the aluminum under warm, dry conditions.

Very truly yours,

GBH:vl EXTRA 57 720 Z

G. B. Hatch

NONDESTRUCTIVE TESTING

Introduction

A variety of nondestructive testing and inspection techniques are being used today in industrial power plants and utility stations. In general, most of these techniques have not been used widely and the bulk of nondestructive testing has been carried out in high pressure utility plants. Since there is little doubt that the use of these procedures will continue to increase, we should closely investigate this subject.

As the term implies, the purpose of nondestructive testing is to determine whether the physical condition of a piece of equipment or product is normal without damaging the item tested. There are techniques which can be used to detect flaws or cracks in such equipment as turbine blades, pump castings, etc. However, we will not be directly concerned with this type of testing in this report.

The general types of nondestructive testing that are usually applied to boilers are:

1. Magnetic or eddy current type
2. Ultrasonic
3. Radiography
4. Visual methods

Magnetic or Eddy Current Test Equipment

The most widely used piece of equipment in this category is the Turner Scale Thickness Indicator. The Turner device is the only magnetic type of test unit which is designed specifically for determining thickness of scale and deposition in boiler tubes. This unit was patented in 1949 by Howard Turner, an engineer with the Consumers Power Company and is presently sold by Haskins & Turner Company, Jackson, Michigan.

The Turner unit primarily consists of a probe head, a flexible cable reaching between the probe,and indicating meter, and a 50 ft. graduated spring steel tape which is used to move the probe back and forth inside the tube. A spring steel shoe holds the contact feed of the coil against the opposite side of the tube. The meter is calibrated in thousandths of an inch and supposedly directly indicates the thickness of scale present in the tube. Generally, two men are required to operate the unit; one to maneuver the probe and one to record meter readings and the distance the probe has traveled down the tube.

The Turner gauge is based on the principle that the impedance of a coil, through which alternating current is passed, is influenced by any conducting material in proximity to this coil. Althernating current is passed through the coil producing a magnetic field. The field causes eddy currents in the tube metal which, in turn, affects the impedance of the coil. Since the effect

on coil impedance is related to the distance between the coil and the tube surface, electrical measurements made on the coil circuit provide an indication of the thickness of scale separating the coil and the tube surface.

Accurate measurements of scale thickness are directly dependent on the condition of the tube surface beneath the layer of scale. Flaws or pits in the tube metal will cause erroneous indications of scale thickness; however, this is actually an advantage because the extent of metal loss in the tube is indicated by the erratic action of the meter. Nevertheless, inaccurate readings will generally be obtained when the probe head is passing in a tube bend. Also, if the scale layers permanently consist of conductive materials such as magnetic iron oxide or copper, the indicated thickness will be low. Literature references indicate that the accuracy of the Turner gauge is in the range of 4-10 mils. The price of the Turner Scale Thickness Indicator is approximately $400.

Several of our clients (International Paper, Natchez, Mississippi; Bethlehem Steel, Sparrows Point, Maryland, Appalachian Electric Power, Logan, West Virginia; and National Lead Company, Sayreville, New Jersey) have used this device extensively and seemed to have been satisfied that it is a worthwhile test device. However, the fact that it cannot always be relied upon to give a true indication of tube conditions was verified by one man attending our 1960 Utility Seminar. He said, "We felt that the Turner gauge provided a good indication of tube conditions until a tube failed shortly after a planned outage. During the outage the tube had been tested with the Turner gauge and showed no indication of abnormal conditions."

It was the opinion of many attending the Refresher Course that the Turner gauge can be used in obtaining a rough indication of the condition of boiler tubes. Only after considerable experience with this gauge, some plants are able to obtain reliable results based on their past data.

In the early 1940's, the Shell Development Company produced the Probalog, an instrument for inspection of nonmetallic heat exchanger tubes. This unit was designed to be operated by one man in order to detect metal loss resulting from corrosion. An indication of metal loss is obtained by passing a probe head through the tube while the recording meter makes a tracing on a strip chart. A significant amount of experience is required in order to properly interpret these tracings.

From the meager technical information available on the Probalog, it appears that it falls into the category of an eddy current unit. The Probalog can be used only for tubes of the following metals: copper, brass, Inconel, Admiralty metal, cupronickel, Muntz metal, aluminum and stainless steels.

Ultrasonic Testing Equipment

Ultrasonic testing devices are finding increased acceptance for nondestructive testing of boiler tubes. These units are sold by several companies and the following is a partial list of the varied instrumentation that is available:

1. Audigage and Vidigage, Branson Instruments Company, Stamford, Conn.
2. Reflectoscope, Sperry Products Inc., Danbury, Conn.
3. Sonizon, Magnaflux Corporation, Chicago, Ill.
4. Immerscope, Automation Instruments, Inc., Columbus, Ohio

Basically the ultrasonic method is similar to the sonar devices used on submarines. The equipment consists of a sound transmitter, a receiver, an amplifying system for the received signal and a means of presenting the signal to the operator.

Operation of all ultrasonic test devices depends on the fact that high frequency sound behaves similar to audible sound. Ultrasound is transmitted at the same speed as audible sound through liquids and metals. However, the fact that ultrasound is not transmitted well through air has an important bearing on the mechanics used in ultrasonic test equipment.

The following three methods are used in ultrasonic testing:

1. Pulse echo
2. Resonance
3. Transmission

The transmission technique utilizes a signal generating crystal on one side of the metal piece and a receiving crystal on the other. Since access to both sides of the item tested is required, this method is not applicable to boiler tube testing.

The pulse echo and resonance methods require access to only one side of the item being tested. The instruments mentioned previously fall into the following two categories. The Vidigage, Audigage and Sonizon instruments are of the resonance type; while the Reflectoscope and Immerscope are pulse echo instruments. All of these instruments will measure thickness of the item tested and will determine if and where it has an internal flaw.

The various steps which take place in the operation of the Reflectoscope are:

1. An electrical impulse is generated in the Reflectoscope.
2. The electrical impulse is transformed into mechanical vibrations by the crystal.
3. The pulse of high frequency vibration is projected into the material by the crystal.
4. A portion of the pulse strikes the defect and is reflected back toward the entrant surface and a portion continues through the opposite boundary.
5. The beam of vibrations is reflected from the back surface toward the entrant surface.
6. The returning pulses reach the crystal where they are transformed into electrical impulses.
7. The returning energy is amplified electronically by the Reflectoscope.
8. The amplified signals are displayed on the cathode-ray tube screen as vertical pips. These pips are spaced along the horizontal sweep line from left to right according to their time of arrival. Their spacing is in proporation to the distance between the points in the material they represent. Square wave markers superimposed on the sweep line are used to represent increments of measurement such as feet, inches, etc.

In a resonance instrument, the crystal vibrates over a range of frequencies. The ultrasonic wave travels through the material and is reflected by the opposite surface. At certain frequencies, when the transmitted and reflected waves are in phase, there will be a relatively large increase in the amplitude of the wave in the material. The detector part of this apparatus determines the frequency at which resonance will occur. Resonance occurs at a fundamental frequency which is inversely proportional to twice the thickness of the material tested and as a result, determination of the resonant frequency is a measure of the unknown thickness.

To summarize, the pulse echo method depends on measurement of the time required for an ultrasonic wave to pass through the material tested and be reflected back to the crystal. The resonance method depends on determining the fundamental frequency which is required to produce resonance in the material tested. The various instruments utilize different methods of presenting the return signal to the operator. A cathode-ray tube is used in the Vidigage, Reflectoscope and Immerscope. With the Audigage, the resonant frequency is detected by means of a set of headphones worn by the operator and the use of a milliammeter on the panel of the instrument. A stroboscopic type of device is utilized by the Sonizon instrument in order to determine resonant frequency.

The crystals, which are sometimes referred to as piezoelectric cyrstals or transducers, are usually quartz or a quartz-barium titanate type of sandwich. Quartz crystals can withstand temperatures of 300°F continuously and 400°F in intermittent service while the quartz-barium titanate sandwich crystals should not be used at temperatures exceeding 180°F. Under ideal conditions, ultrasonic devices can measure very accurately the thickness of any material which will conduct sound.

As mentioned earlier, ultrasound is not transmitted well through air. In order to get good transmission of the ultrasonic vibrations into the article tested, a good couple between the crystal and the test article must be obtained. In the case of boiler tube testing, the external surface of the tube must be clean and smooth since the crystal is held directly on the tube surface. This contact between the crystal and the tube surface also results in wear on the face of the crystal and leads to early failure of the rather expensive crystal. Fortunately, both of these problems are largely eliminated by using a liquid couple. With this modification, the crystal is enclosed in a special fixture called a dolly and the liquid is continuously supplied to this dolly at a pressure of approximately 60 psi.

Ultrasound is refracted at the interface between two different mediums in much the same manner as light. In order to get an accurate measurement of tube wall thickness, the ultrasound beams must strike the external surface at an angle of 90°. If the external tube surface is rough, much of the beam is scattered and the signal returning to the amplifier is weakened. In many cases, it is necessary to sandblast external surface of the tubes in order to obtain a satisfactory response from the ultrasonic test equipment.

These same limitations apply to the internal surface of tube being tested by ultrasonic means. If metal loss on the internal tube surface is fairly uniform, ultrasonic equipment will accurately determine the wall thickness. However, if the internal metal loss is confined to very small areas and the surface exhibits sharp discontinuities, accurate measurements are not possible and in some cases

the signal is lost due to the scattering effect of the internal surface. This problem can be alleviated somewhat by transmitting a narrow ultrasonic beam and the development of smaller, more sensitive crystals made of a material such as lithium sulfate to reduce the difficulties experienced or encountered by a rough or tapering reflecting surface.

Tightly adherent deposits on the internal surface of the boiler tube will also interfere with accurate determination of wall thickness. Such deposits blur the readings of the ultrasonic test devices in a characteristic way and although accurate determination of wall thickness is not obtained, these readings do provide a fairly consistent indication of adherent deposits. With a suitable crystal and ultrasonic frequency, these units will measure thickness from 1/16 of an inch to 12 inches.

There does not seem to be much question that an experienced operator is required to fully interpret ultrasonic test results; however, an inexperienced operator can generally get accurate thickness measurements on good tubes. Experience becomes an absolute necessity when interpreting results obtained from tubes exhibiting sharp discontinuities.

The cost of most portable ultrasonic test devices is in the range of $900 to $1500. Some companies supply a complete testing service and will provide personnel and equipment on a per diem basis.

In reference to the Audigage, members of the Refresher Course stated that the external surfaces of the boiler tubes must be very clean in order to obtain reliable results. Cincinnati Gas & Electric Company was unsuccessful in their attempt to use this instrument. However, the Audigage was used at Jones & Laughlin Steel Corporation in Aliquippa, Pennsylvania to detect embrittlement cracks with extreme success.

Radiography

The chief asset of radiography is that it permits measurement at considerable depth within the test material. It is necessary to use high frequency waves in order to penetrate into the interior of the test material. The principal difference in the various types of radiographic equipment is in the source of radiation.

The basic principle of radiographic measurements involves a determination of the extent to which the rays are absorbed in passage through a tube section. Such absorption is a function of the thickness of the metal through which the radiation must pass. Any flaws in the wake of the rays decrease the total metal thickness when compared to the surrounding smooth surface. Such a flaw will make a dark impression on the photographic plates so that the determination is made visually.

The two major sources of radiation are X-rays and gamma rays. X-rays have been used for a considerable length of time and are utilized in the majority of radiographic equipment. They are emitted from a metal plate (usually tungsten) which has been bombarded with electrons obtained by applying a high electric potential to an evacuated tube. The major advantages of X-rays over gamma rays are:

1. A shorter period of exposure is required.
2. Better contrast can be obtained by the use of X-rays.

However, X-rays call for the use of fairly costly equipment and only one test piece can be exposed at any one time. Many places in a power plant are inaccessible to the cumbersome equipment that is necessary for the use of X-ray generation.

On the other hand, a gamma-radiator has these definite advantages:

1. The gamma-radiator is a very small source and can be used in numerous locations where X-ray equipment cannot be mounted.
2. The material itself is inexpensive and consists primarily of a number of film holders, a means for fixing specimens in the desired positions, and a stand for holding the container of the radioactive sources.

However, the high cost and the short life of radium havebeen chiefly responsible for the limited amount of interest which gamma-ray emitters have attracted. Nevertheless, the isotopes of Iridium 192 and cobalt 60 have opened up a new source of available materials. Gamma-rays emitted by Iridium 192 possessa relatively low energy level resulting in a highly suitable source for analyzing sections of steel up to 2 inches in thickness. At the same time, the low energy level reduces the extent of protective measures which must be taken for the operator's safety. The disadvantage of this source lies in its relatively short half-life which necessitates fairly frequent changing.

The high intensity of cobalt 60 gamma radiation makes it an ideal source for objects with high subject contrast. Even though it has a shorter half-life, it is a cheaper source than radium. The sensitivity of cobalt 60 radiographs is inferior to those using radium as a source and substantially below the sensitivity obtained by using X-rays. However, exposure time is significantly less than called for by radium. It must be pointed out that when using cobalt extreme precautions must be taken to insure the safety of the operators.

Members of the Refresher Course reported the following information on the use of gamma-ray radiography;

Niagara Mohawk has replaced a large number of tubes based on radiographic testing. Further examination confirmed the accuracy of these tests.

Tampa Electric Company has used this test procedure extensively with excellent success. The only poor results that were obtained were in areas where film exposure was difficult due to the construction of the specific unit involved.

Visual Types

A. The Boroscope

The boroscope is a precision optical instrument which can be used to visually inspect the internal condition of boiler tubes. Many models of these boroscopes are provided with fixed diameters and with optical systems designed to provide direct,right angle and retrospective vision.

Boroscopes which are especially designed for our plant work are usually made in six to nine foot sections with attachable parts to provide an instrument of any required length. Other applications of the boroscope involve use in examinations of turbine blades, generators, motors, pumps, and other electrical and mechanical components.

The right angle boroscope is furnished with an integral lamp positioned ahead of the objective lens. This optical system provides vision of approximately 1 inch in diameter at right angles to the axis of the telescope at a distance of 1 inch from the objective lens. This instrument is particularly applicable in inaccessible corners and bends in boiler tubes.

B. Fiber Optics

Fiber optics is a recently developed method of transmitting images through the use of a long snake-like pipe line consisting of glass fibers assembled in a flexible bundle. One end of the slender cable is pointed at the subject while each individual fiber reflects a tiny dot of light which is transmitted intact along the system of fibers. At the other end of the cable, the system of dots reproduces the image of the subject.

Fiber optics is based on the principle that once light is trapped in a medium (such as glass) it will bounce from wall to wall until it comes to the end of the tube.

However, the reproduced image of the subject is not as sharp as required in boiler tube inspections. Since this method is in its early development stages, it might have future useful applications.

Members of the Refresher Course made the following commentary on the use of the visual methods:

Undamaged surfaces are observed accurately by the boroscope. However, there is considerable doubt that damaged surfaces could be detected due to distortion, magnification, and loss of perspective. The Long Island Lighting Company has drilled holes through several chronically problem tubes; the boroscope is inserted and the internal surfaces of the tubes are periodically examined. This plant uses these observations as a guide to determine whether an acid cleaning is necessary.

Dr. Partridge mentioned that the Germans have recently been experimenting with the use of a small television camera and receiver. Although the only reported attempt to use a television camera in this country met with difficulties, it is apparent that when future applications of television are perfected, they will be extremely beneficial.

CALGON CORPORATION

SUBSIDIARY OF MERCK & CO., INC.

HALL LABORATORIES

9-1009
March 26, 1964

TECHNICAL TIP 74
(Confidential Notes for Hall Engineers)

BOILER METAL FAILURES AND THEIR DIAGNOSIS WITH THE METALLOGRAPHIC MICROSCOPE

99% of all boiler metal failures fall into three categories as far as their cause is concerned. The largest number are caused by excessive temperatures. Stress or fatigue is responsible for about 20% and chemical attack for perhaps 10%. Of course, very few failures can be attributed to only one specific cause. Most failures involve a combination of two or more of these factors.

In diagnosing boiler metal failures, the metallographer selects representative areas on the section to be examined and removes very small specimens to be polished and etched for study under the metallographic microscope. A typical mount containing three of these specimens ready for examination is shown in Figure 1. The specimens are cast in plastic for convenience in handling during polishing. Perhaps you can see the specimen on the stage of the metallograph in Figure 2. This microscope is specifically designed for metallographic studies.

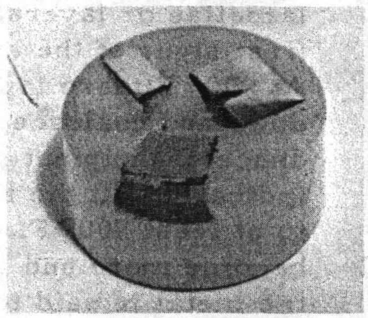


Figure 1

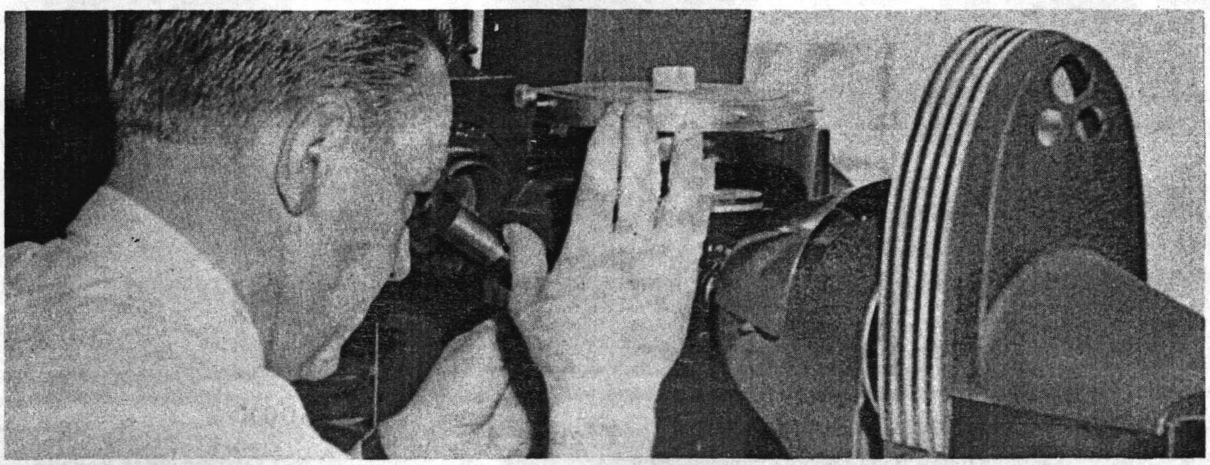


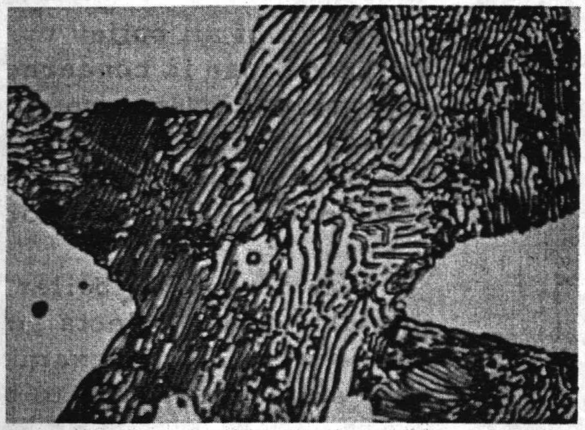
Figure 2

Mailing Lists A & B

Excessive Temperatures

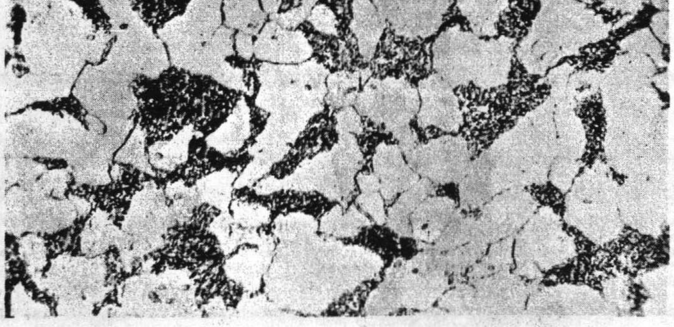
Since overheating is the most frequent cause of failure, we shall discuss it first. Under ordinary service conditions most of the boiler metal should be well below 800° F. At these temperatures the boiler metal suffers no structural change during the service life of the unit. Long periods of service at 900° F will produce evidence of change in the metal structure.

Low carbon boiler steel with its 0.2% carbon will in the normal condition generally have a structure similar to that shown in Figure 3. The structure is made up of a pattern of light-colored iron grains called ferrite interspersed with dark-colored pearlite (iron and iron carbide). Notice that the pearlite is made up of very fine layers in this normal, lamellar condition. These lamellae or layers of carbide show the first signs of the effect of overheating. At 900° F these layers begin to break down and coalesce into spheres. Evidence of incipient breakdown usually indicates that the metal has been heated to at least 900° F. At higher and higher temperatures the carbides become more and more distinctly spheroidal. When completely so, the metal is said to be spheroidized, and such a structure, illustrated in Figure 4, indicates that temperatures above 1000° F were reached.



2000X

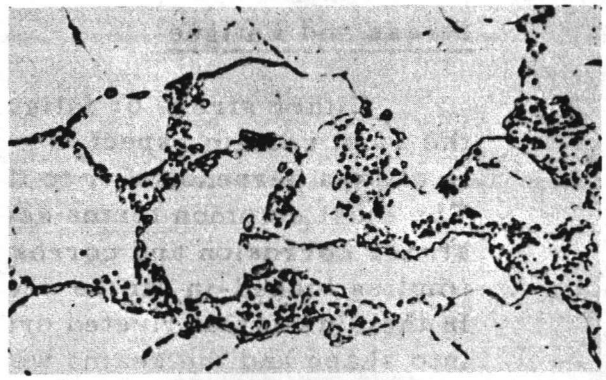
Figure 3



500X

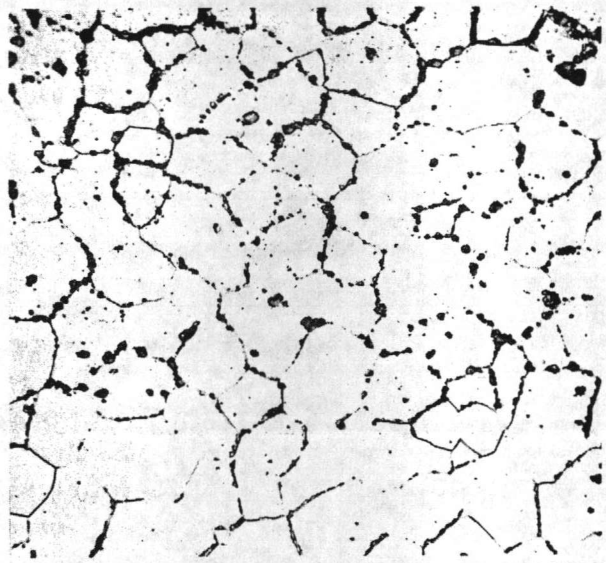
Figure 4

At still higher temperatures, the dense colonies of spheroidized carbides begin to disperse and gradually migrate to the ferrite grain boundaries. Such a structure is shown in Figure 5. This indicates that temperatures near 1200° F had been reached. After the carbides have concentrated at the grain boundaries, they begin to disappear and the metal becomes decarburized. Decarburization occurs at temperatures well above 1300° F. At temperatures of this magnitude intergranular oxide penetration, generally from the outer surface, begins to take place. Such penetration is shown in Figure 6. This metal has practically been burned to a crisp, probably at temperatures as high as 1600° F.



500X

Figure 5



500X

Figure 6

Before leaving the subject of temperatures and structural changes due to temperatures, we should mention one other aspect. When a low-carbon steel is heated to a temperature above 1330° F, the lower critical point for such a steel, and is suddenly quenched to a temperature below 400° F, the structure assumes the pattern shown in Figure 7. This is a modified martensite. In almost every case in which a tube has blistered and burst, the sudden escape of water and steam from the overheated tube quenches the metal and produces this martensitic pattern.

500X

Figure 7

Stress and Fatigue

Either stress or fatigue is involved when a metal cracks. Probably the most certain aspect of a failure involving a crack is that the cracking is always perpendicular to the direction of the stress which caused it. The most common terms associated with a failure involving stress are stress corrosion and corrosion fatigue. The term stress corrosion implies locked-in stress developed during the fabrication of the unit. In the old days of riveted drum boilers the drums were oftentimes forced into shape and the seams were badly stress loaded and held together with rivets. How fortunate we all are that the riveted drum boiler is rapidly becoming a thing of the past. These riveted seam drums set up conditions for a special type of damage known as caustic embrittlement, which is a form of stress corrosion. A distinct characteristic of this damage is the intergranular (around the grain) path of the cracking. The caustic selectively attacks the grain boundaries of the metal and the stress focuses there to produce intergranular cracking.

Where caustic is not involved but the more common stress corrosion is, the cracking is found to be transgranular (across the grains). As a rule when stress corrosion has caused a failure, there will usually be more than one crack involved.

Corrosion fatigue refers to dynamic stresses, fluctuating as the equipment operates. This form of cracking is also transgranular, making the distinction between a failure due to stress corrosion and corrosion fatigue difficult. Here other features of the failure must be considered so that a more accurate diagnosis can be reached. One feature of stress corrosion damage is that the cracking generally is at the bottom of a pit on the surface. It is also generally true that stress corrosion is manifest by a number of cracks rather than just one or two. Still another feature of stress corrosion cracking is the fact that the cracks will be almost filled with corrosion product. A fatigue failure will more often show a nearly clean fracture with voids in the cracks.

Chemical Attack

Metal loss due to oxygen or chemical attack is another of the more perplexing problems. Metal loss does not as a rule leave behind any evidence of its cause. All we can see under the microscope is that some of the metal is missing, and we can usually see this without the microscope. Here again the physical characteristics of the tube and its appearance can tell us much.

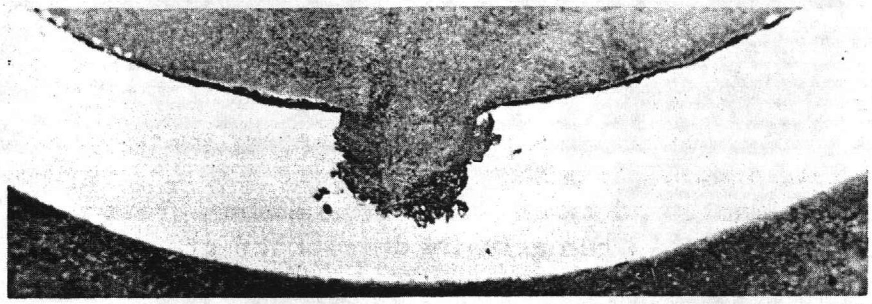
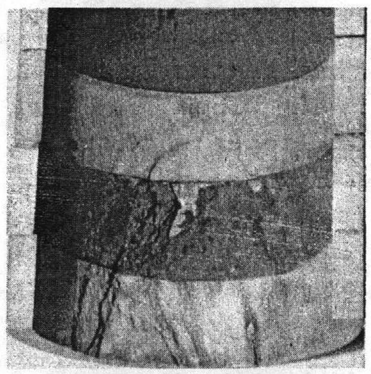


Figure 8 4X

Observe, for example, the tube surface shown in Figure 8. Even the untrained eye might suspect that this is due to acid attack. It has a rough, etched appearance, and the pitting is usually undercut.

Caustic gouging, on the other hand, leaves the tube wall very smooth, as shown in Figure 9. It may be irregular and bumpy, but generally the surface itself will be smooth. Oxygen pitting also may leave behind a fairly smooth surface, but in this case the pits will be widely separated and a series of distinct pits will be observed.



Before and After Cleaning

1/2 size

Figure 9

Hydrogen Damage

This is included in this treatise more for its interest than for its frequency of occurrence. Only about 20 cases of it have come to our attention in about that many years.

Water and steam in a hard worked boiler tube will produce a layer of iron oxide on the wall of the tube. What is sometimes overlooked is that this reaction also produces hydrogen. The hydrogen generally escapes along with the steam and has no effect. However, under certain conditions, such as when there is a large tubercle of dense iron oxide on the tube wall, the hydrogen produced beneath this tubercle finds it easier to penetrate the tube wall than to work its way back into the circulation

stream. Nascent hydrogen, the smallest atom known, can penetrate a solid wall of steel with comparative ease. On its way through the tube wall the hydrogen can come in contact with the carbides of the steel, and when it does so, it can unite with it to form methane (CH_4). This methane, once formed, is locked in place, so to speak, by its mere size. It can no longer migrate because it is too bulky. More and more hydrogen coming along produces more and more methane, and soon great pressures are built up. This pressure can actually disrupt the grain boundaries and form short intergranular cracks. Sufficient external pressure on the tube then can cause a series of these short cracks to unite and a characteristic thick-edged failure occurs.

Figure 10 shows pretty much of the whole story in one illustration. The failed tube with a window section blown out is at the top. Notice the thick-edged break. A little macroetched section is shown just below the tube. The dark area of the etched section is typical of H_2 damage. The two micrographs, one from near the inner surface and the other from near the outer surface, are at the bottom and show damage to the normal structure.

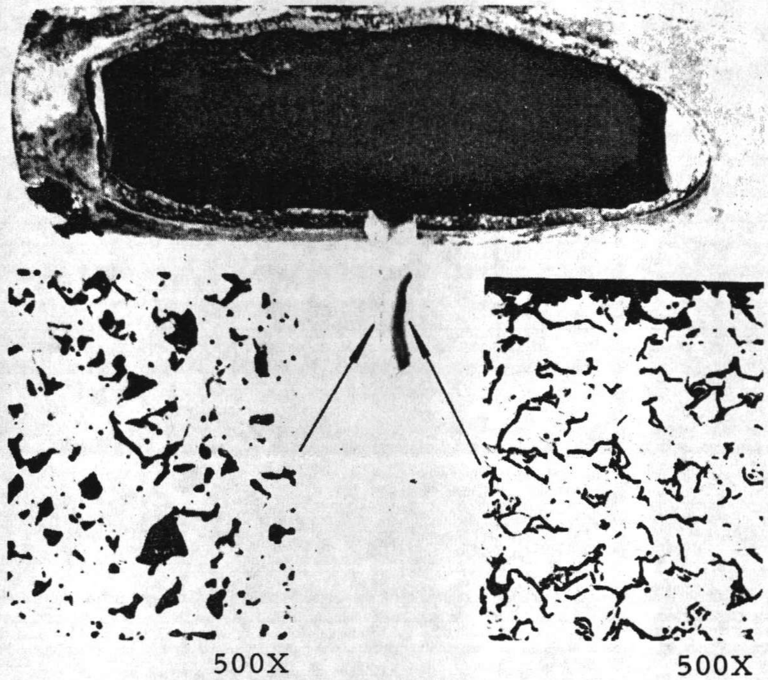


Figure 10

Faulty Tubes

Since we've already introduced rare type failures, let's go one step further and consider failures due to faulty tubes. Surprisingly, perhaps, this is the least frequent cause of failures we come across. All six of the cases we have seen were due to the presence of a "pipe" in the ingot from which the tube was made. The appearance of a failure from this cause is quite characteristic. A portion of the tube wall peels

away from the wall, oftentimes not unlike a layer of paint peeling away from a rain gutter. An example is shown in Figure 11.

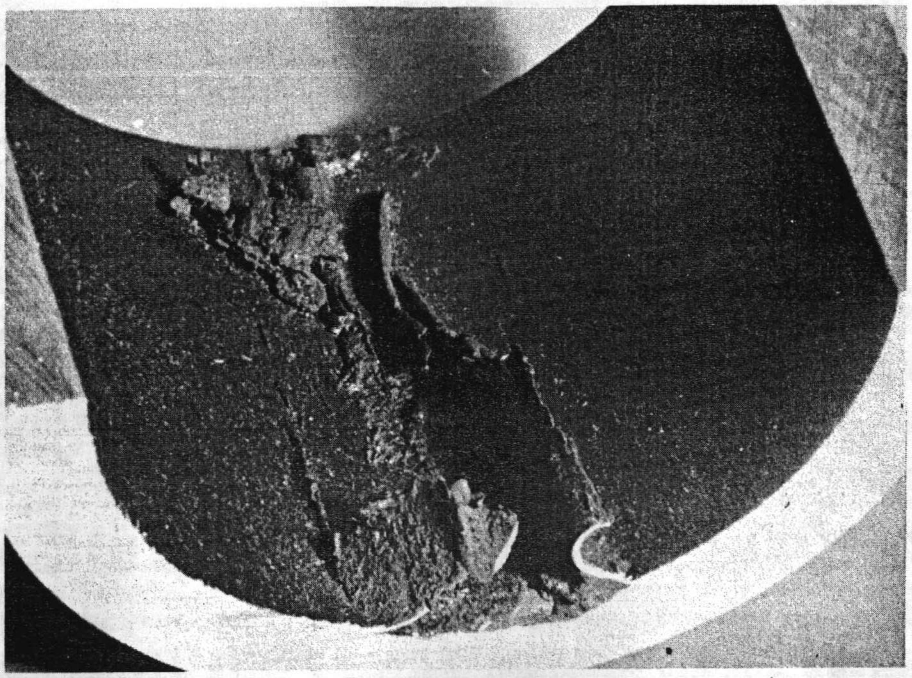


Figure 11

Conclusion

The above compendium may, of course, tend to oversimplify the many aspects of the diagnosis of tube failures. It can, however, serve as a guide, describing some of the trials which are followed in searching for an answer to "Why did this tube fail?".

CONFIDENTIAL

Calgon Corporation

Technical Service Report No. IP-81-T-B-3

POWER/BARK BOILER - TUBE FAILURES

Prepared for: International Paper
Vicksburg, Mississippi

Author: F. H. Seels

Date: December 9, 1981

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W. L. Trace
Boiler Technical Service (file)

KEY WORDS

Boiler
Iron Oxide Deposit
Corrosion

OBJECTIVE

To use Scanning Electron Microscopy (SEM) to determine if a series of corroded tubes had experienced metal loss due to the presence of either water treatment chemicals or furnace side ash chemistry.

This report concludes a preliminary report given to C. Peters on September 22, 1981.

BACKGROUND OF PROBLEM

The power bark boiler at this plant has experienced severe tube wall thinning of about twenty convection pass tubes, at a point where the tube enters the steam drum. In all cases the metal loss is on the fireside of the tube, and localized to a small band where the tube intersects the drum, as shown in Figure 1.

This boiler was installed in 1967 and has had a history of mechanical problems resulting in tube-end leaks, and cracks in the steam drum. There has been a succession of problems with tubes sealed-off from service with plugs or with blind nipples. In 1977 tubes between the steam drum and mud drum were rerolled or replaced. Recent ultrasonic testing by Southwest Research has shown that some of these tubes have experienced 60% metal loss where tube ends enter the steam drum. Calgon suspects that weeping of boiler water between the tube end and the drum wall has contributed to the formation of localized corrosion sites.

EXPERIMENTAL

Seven boiler tube end specimens were submitted for inspection. Two were selected for SEM study. These were selected on the basis of: clearly defined corrosion cell boundaries; the presence of undisturbed corrosion products; and minimal abuse from torch cutting during removal from the boiler.

A very noticeable feature of the specimens was the sharply defined, smooth walled (appears almost polished) character of the corrosion cells.

All seven specimens showed a loss of wall thickness ranging from about 20%, up to 100% at the site of a failure. In most cases, a circumferential band of corrosion had resulted in a band of magnetic corrosion products filling the corrosion cell. The oxide is dense, brittle and ridigly in place. With slight manipulation the oxide plug will "pop" out of the cell and leave a smooth walled, radiused trough remaining in the metal.

The two specimens studied with SEM were sampled as shown in Figure 1. To determine the possible role of water weeping between the tube and the drum wall, a comparison was made of surface chemistry at the five points shown in Figure 1:

A) Tube surface at an area previously in contact with drum

B) Metal surface at bottom of corrosion cell
C) Interface between corrosion products and surface (B)
D) Corrosion products at a freshly exposed surface of corrosion product cross-section
E) Tube surface at an area previously exposed to furnace gas

Photomicrographs 1, 2 and 3 show representative features of the specimens studied. Photo 1 shows a cross-section of the tube wall, and a portion of the corrosion cell where magnetite corrosion products have been broken away. Notice the brittle, crystalline character of the freshly exposed iron oxide fracture surface, and the smooth walled, uniform nature of the gouged area. Photo 2 is a close-up of Photo 1 showing details of the interface between iron oxide (left side of photo) and metal (right side of photo) at the bottom of the corrosion cell. Photo 3 is a further close-up of Photo 2.

Of the specimens submitted, Numbers 3 and 7 were analyzed for chemical composition using x-ray emissions obtained during the SEM study. Table 1 summarizes findings of surface chemistry (excluding iron) at the five areas identified in Figure 1. More detailed information is given in the respective x-ray spectra shown in Figures 2 and three which compare point A on specimens 3 and 7, respectively.

TABLE I
Elements in Deposit

	Specimen 3	Specimen 7
A) Tube in contact with drum	Na, Si, S, P, Cl, K, Ca, Mn	Si, Ca, Mn
B) Metal surface beneath corrosion products	Only Fe x-rays were observed	Same
C) Interface iron oxides/ surface B	Not Analyzed	Na, Si, S, Ti
D) Corrosion Products	Na, Si, P, S, Cl, K, Ca, Mn	Na, Al, Si, S
E) Tube exposed to furnace	Na, Al, Si, P, S, K, Ca, Ti, Mn	Na, Al, Si, P, S, K, Ca, Mn

A comparison of x-ray spectra shows specimens 3 and 7 to be rather different. Only specimen 3 shows strong evidence of boiler water salts. For specimen 3 the x-ray peaks for phosphorous in all areas is reasonable evidence that leakage of boiler water was involved. Specimen 7 shows little evidence of boiler water salts. Little is known about fireside ash chemistry but the elemental analyses of area E gives an indication of chemistry contributions from the fireside environment.

CONCLUSION

A. Considering the circumstances, I believe that an iron water reaction is responsible for the metal loss. This judgement relates to several observations:

1) The tube end problems observed in these specimens are very uncommon, and likely related to mechanical aspects of the tube/drum interface.

2) There is generally little visual or chemical evidence of salt residence on the deposits received. The corrosion cells do not appear associated with a large leak or an accumulation of boiler water salts.

3) There has been sufficient time (months-years) for a slow process to take its toll. In this case, only a small amount of water (steam) reactant would be required.

4) The in situ iron oxide slug is unusually dense and crystalline.

5) The oxide shows little evidence of significant increase in volume from the base metal that produced the oxide.

6) The in situ iron oxide is relative pure.

In summary, the presence of water soluble salts would be relatively unimportant since water (steam) was the principle reactant for transforming steel to magnetite. Knowledge of metal temperatures and fireside chemistry would be necesary to speculate further.

In comparison, a corrosion process involving direct participation with an aqueous brine would result in dissolution and reprecipitation of iron. This would generally produce an iron oxide corrosion product with a high degree of porosity, a large increase in volume from the parent metal, and poor mechanical strength.

B. The many mechanical problems with tubes connecting the steam drum and the mud drum indicate excessive stress and strain. This likely relates to the movement of structural components during thermal excursions associated with daily boiler operations. Stress and strain could stimulate the formation of corrosion cells as well as cause water leaks that would supply reactant (water) to the corrosion cell.

C. Since this boiler shows much evidence of unusual mechanical problems, I find it more logical to assume that water weeping has occurred, than to assume no water (steam) leaks. There is no obvious evidence to support a strictly fireside rationale for the corrosion cells observed.

Frank Seels

F. H. Seels, Ext. 8523

Attachments

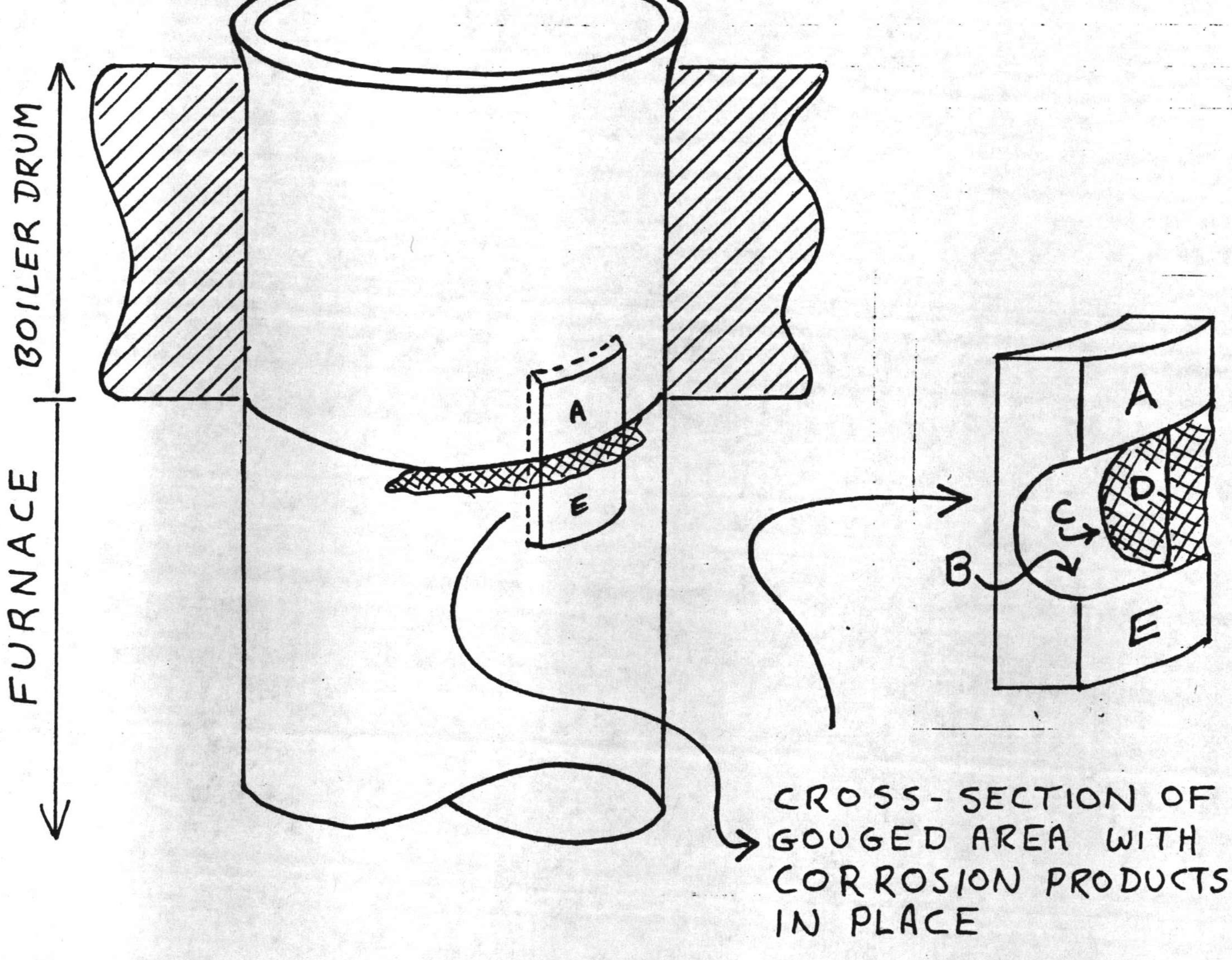


FIGURE 1

CROSS-SECTION OF BOILER TUBE SPECIMEN

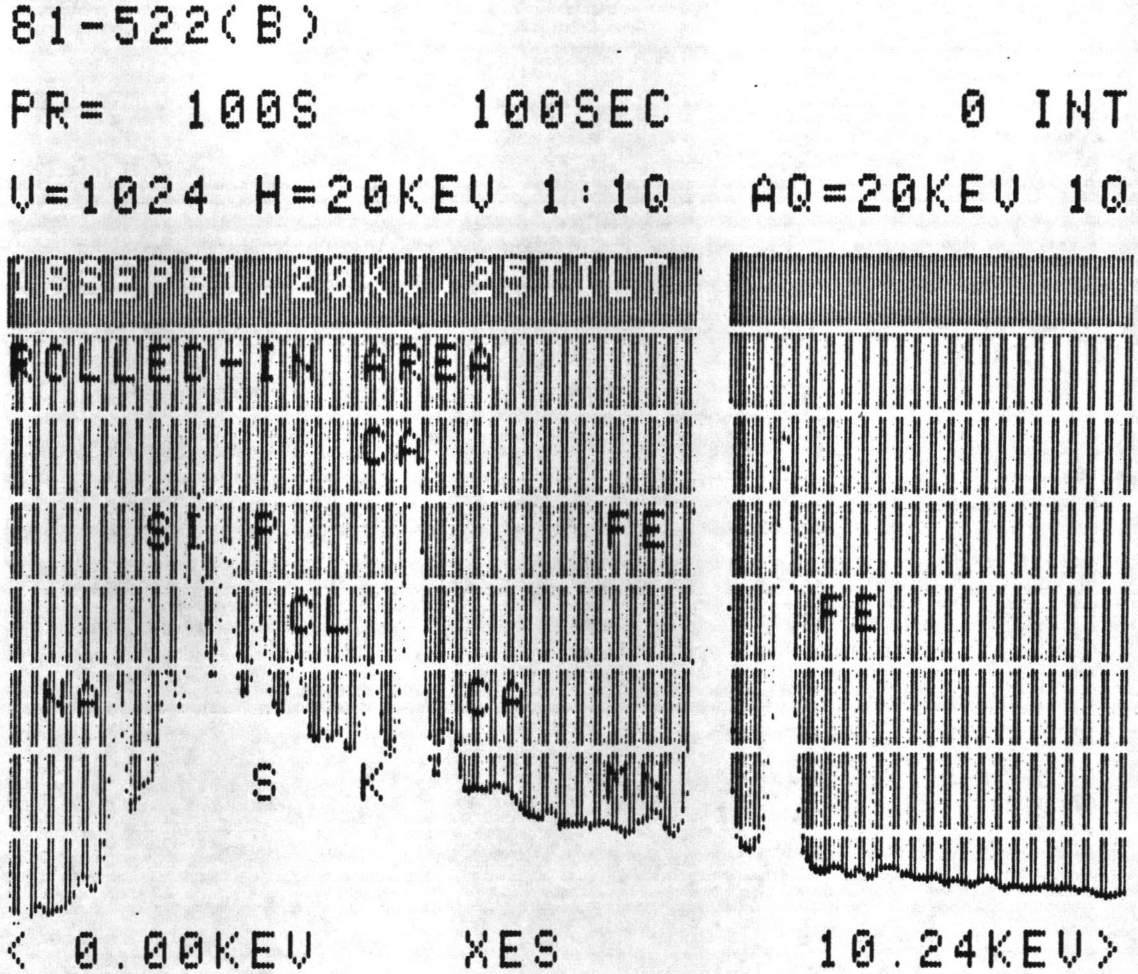


FIGURE 2

X-ray Spectrum for Location A
on Specimen No. 3

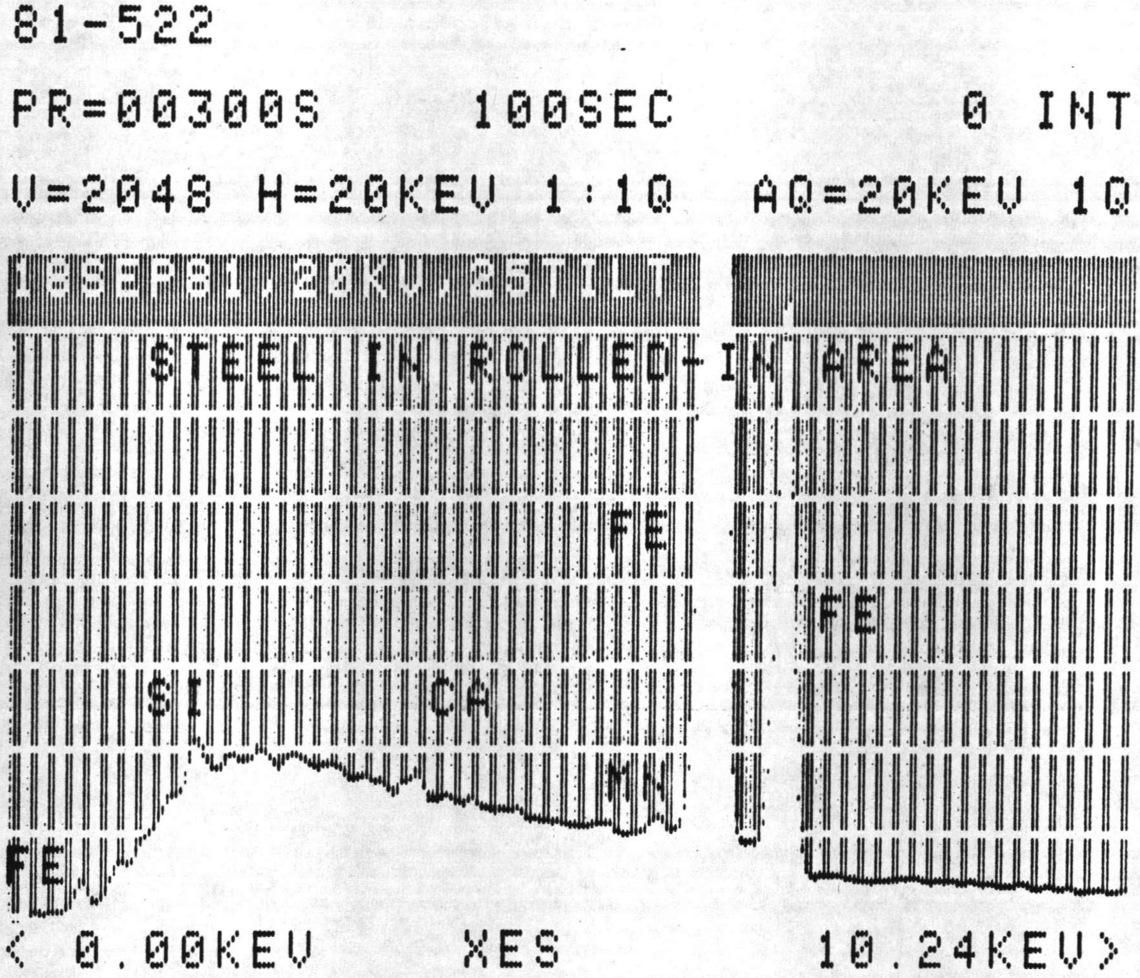


FIGURE 3

X-ray Spectrum for Location A
on Specimen No. 7

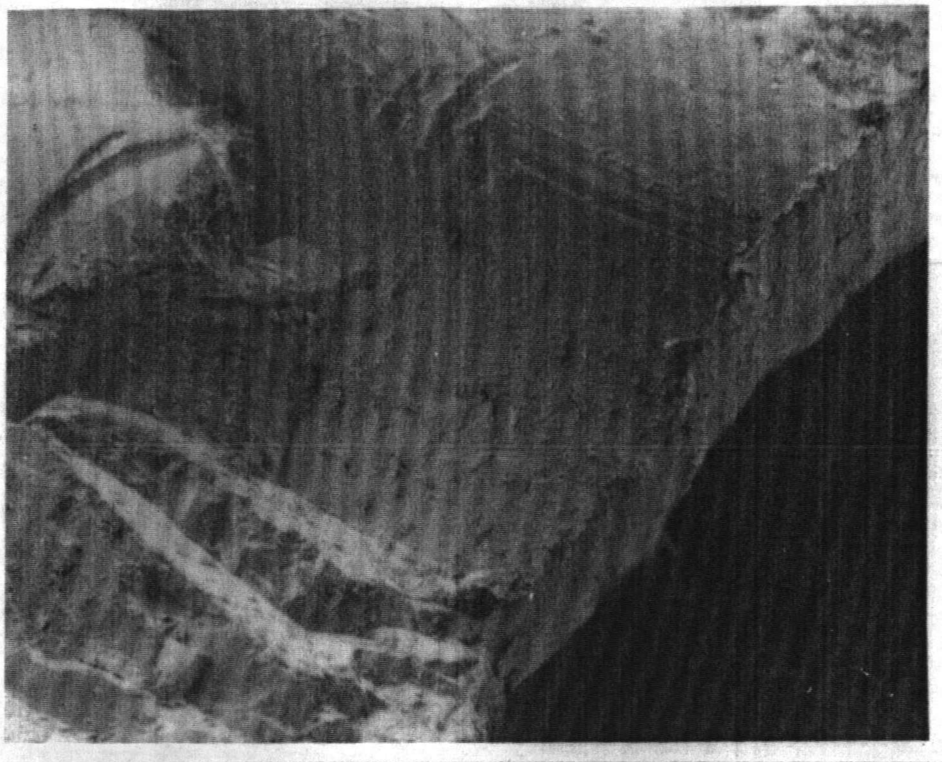


PHOTO 1

Circumferential Corrosion Cell with Corrosion Products in Place (17x)

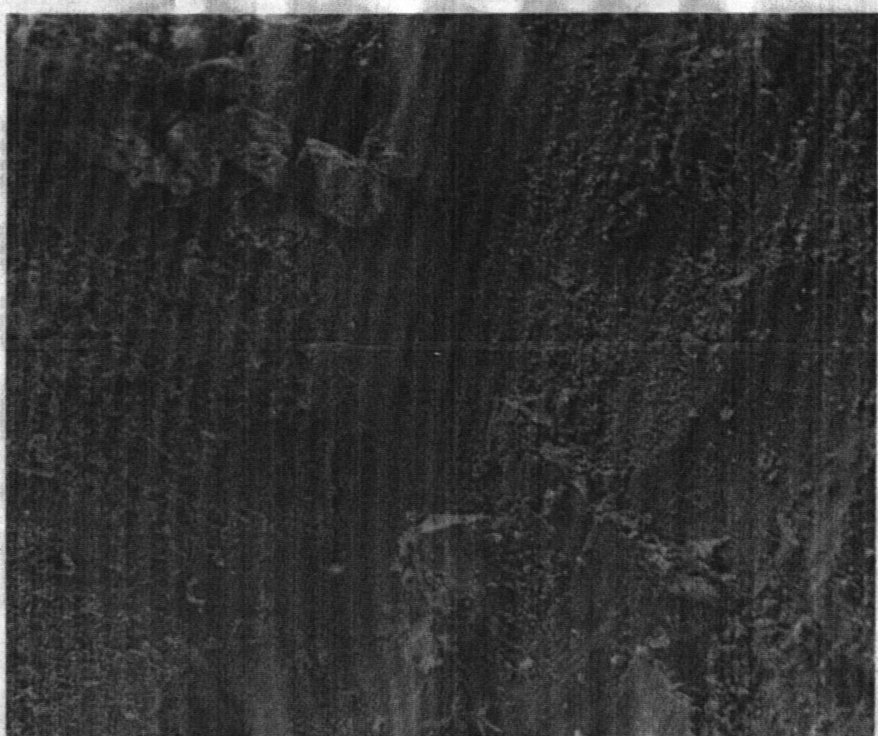


PHOTO 2

Close-up of Deposit/Metal Interface in Photo 1 (90x)

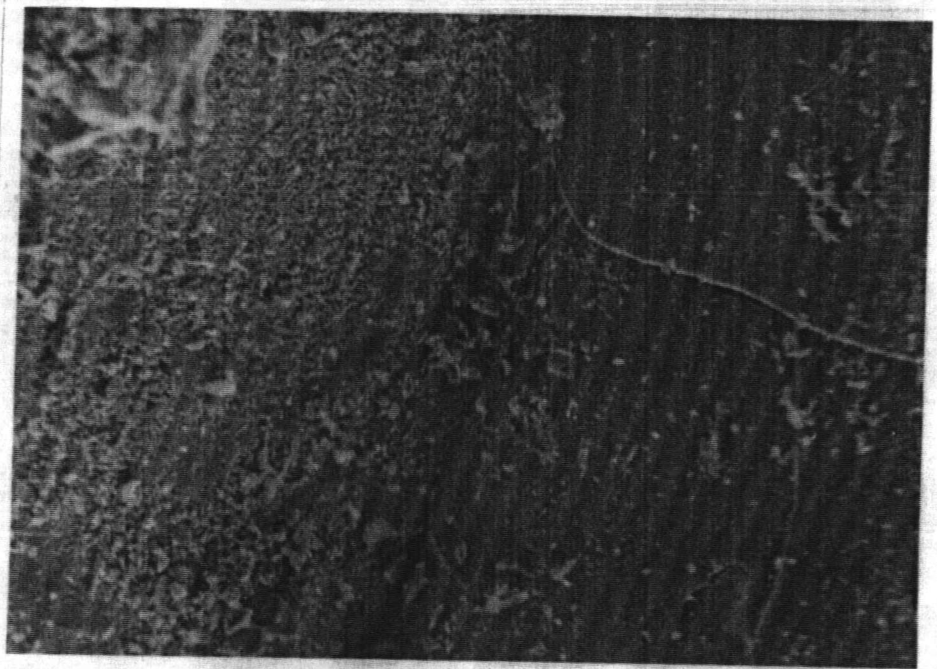


PHOTO 3

Close-up of Deposit/Metal
Interface in Photo 2 (440x)

MEMO

CALGON CORPORATION
SUBSIDIARY OF MERCK & CO., INC.

TO D. P. Warner

FROM R. E. Elliott

SUBJECT NORDEN SYSTEMS, INC.
NORWALK, CT

DATE 9/8/82

It took time to get the old files so I could review both your and Doug Noll's correspondence in 1978 and 1980. Doug has basically told you all that is easily available in the literature:

> "The graphite in grey iron is cathodic to iron and remains behind as a porous mass when iron is leeched out. Graphitic corrosion usually occurs at a low rate. The graphite mass is porous and very weak and graphitic corrosion produces little or no change in wall thickness. A corroded surface usually does not appear different from grey cast iron. Graphitic corrosion does not occur in ductile iron or malleable iron because no graphite network is present to hold together the residue. White iron has essentially no free carbon and is not subject to graphitic corrosion."

> "Grey iron is susceptible to a form of attack known as graphitic corrosion when immersed in soft water, salt waters, mine waters or various dilute acids, or when buried underground in some soils, particularly those containing sulfate. In some instances, erosion washes away the graphitic residue, and the process of corrosion is permitted to continue."

I have no idea where Roth got the concept that sodium sulfite will cause graphitic corrosion. It just does not seem logical and I do not believe it to be true. I certainly support your recommendation that they continue to feed sulfite and I think the elevation of pH to the area of 8 to 8.5 is a sound one to minimize the possibility of acid conditions.

Do you see any indication of poor deaeration in this system? Is there any pitting in the storage section of the deaerator or in the boiler feedwater piping? I would expect the pump to have a long life if it is operated in an oxygen free environment at a pH of 8.5. Is seal water used on the packing glands of this pump and does the seal water come from the pump discharge or is it oxygen saturated city water? Have you run oxygen tests on the feedwater pump discharge line to rule out the possibility of sucking oxygen in the low pressure seal of the boiler feed pump?

Ed/lk

R. E. Elliott

REE/kld

cc: G. W. Groff
S. T. Costa
WMD File

To: Sid Costa

cc: G W Groff

From: Dave Warner
Centerbrook

CALGON CORPORATION
SUBSIDIARY OF MERCK & CO., INC.

SUBJECT Norden Systems, Norwalk, Conn

DATE 7/14/82

MESSAGE

Enclosed is a liner from subjects' Roth feedwater pump. I am requesting that you inspect, etc., and send me a formal report which I can give to Norden Systems on your findings.

The same condition occurred in Oct 78 and April 80. Refer to the WMD file for my report to Norden on 5/29/80 with backup memos from Ron Norris of 5/1/80 and Doug Noll of 10/26/78. Basically it was felt that graphitization of the caste iron had occured. Based on my recommendations they have added BL-409 as needed to hold feedwater pH @ 8.0 - 9.0 with occasional excursions to 9.5 due to carryover.

The problem that exists relates to conflicting recommendations from Calgon and Roth. Roth states "Unreacted sodium sulfite in solution can dissolve the iron lattice in cast iron leaving only the carbon particles. --- should be introduced into the boiler through a by-pass

SIGNED

ATTENTION OF

Reply Message

DATE OF REPLY

feeder in the pump discharge line or through separate chemical feed pumps direct to the boiler." They go on to say that if fed to the DA Heater (as done) it almost always result in pump failure.

Please advise and return the pump liner to me for return to Norden

Thanks,
Dave

SIGNED

FORM NO. 3406 B

RECIPIENT

① Ed Elliott
② WND File

MEMO

CALGON CORPORATION
SUBSIDIARY OF MERCK & CO., INC.

TO D. Warner

FROM H.K. Kolavick

SUBJECT Failed Feedwater Pump Liner
Norden Systems
Norwalk, CT.
Lab No. H3967

DATE 8/13/82

A cast iron feedwater pump liner from the subject plant was received for metallographic examination. Several areas on the velocity face of the liner were severely pitted (Figures 1 and 2) and it was requested that the liner be examined for evidence as to the cause of the attack.

Specimens were removed from both the pitted area and from an area that did not appear damaged. These specimens were mounted, polished, etched and examined microscopically. A photomicrograph was taken of the microstructure adjacent to the pitted area at 50X (Figure 3).

Observations:

The microstructure adjacent to the inside of the pump liner (velocity face) was very porous. This condition existed in all of the examined specimens (Figure 3). There was no evidence of such degradation on the outside surface of the pump liner.

Most of the surface on the velocity side of the liner was rather soft and could easily be scraped from the parent casting.

Conclusion:

It appeared that a form of corrosion known as graphitization had occurred on the velocity surface of the pump liner as evidenced by the soft, porous nature of the mostly ferrite free surface structure.

The deeper pits most probably were located in more turbulant areas on the liner.

H K Kolavick
H.K. Kolavick

N.R. Norris
N.R. Norris

/dm
9467000
COPY: S. Costa
N.R. Norris/H.K. Kolavick
D.W. Whiteside

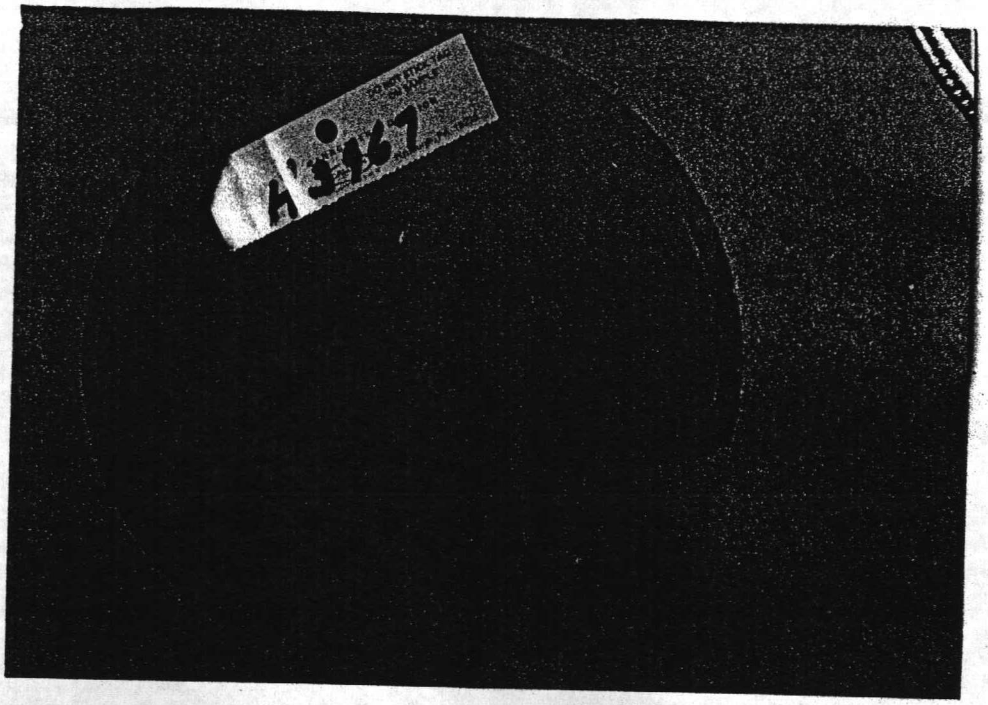


FIGURE 1
Pits on velocity surface

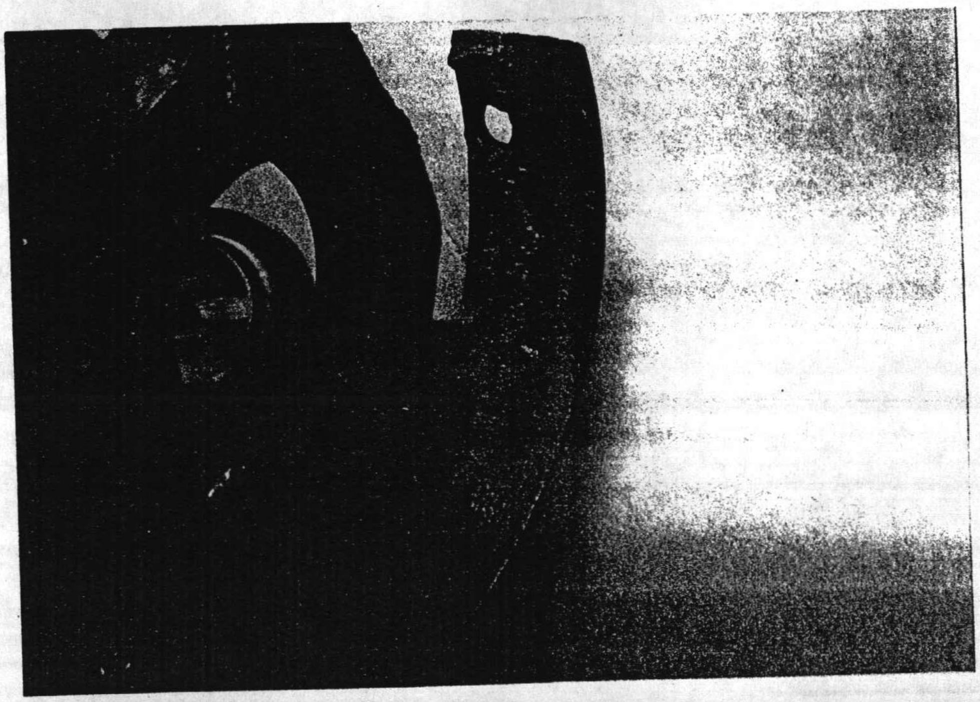


FIGURE 2
Pits on velocity surface

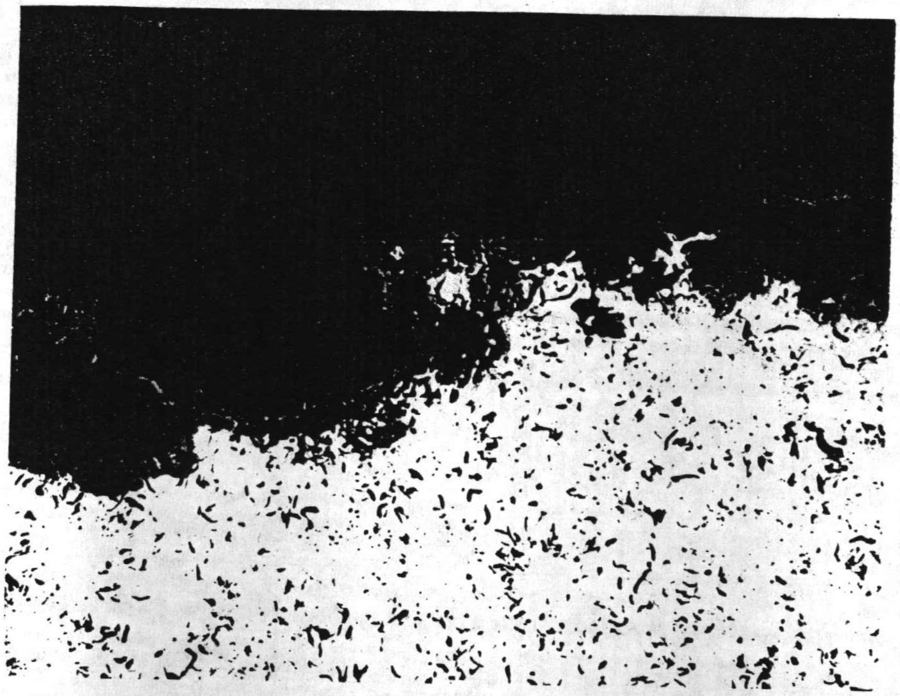


FIGURE 3, 50X
Unetched microstructure adjacent to the velocity face on the damaged liner

ELEMENTAL ANALYSIS

ANALYTICAL TECHNIQUE

X = X-ray fluorescence
C = wet chemical
S = emission spectrographic

	X	C	S	PERCENT
ALL ANALYSES				
Aluminum as Al_2O_3				
Barium as BaO				
Calcium as CaO				
Chlorine as Cl				
Chromium as Cr_2O_3				
Copper as Cu				
Fluorine as F				
Iron as Fe_2O_3/Fe_3O_4				
Lead as PbO				
Magnesium as MgO				
Manganese as MnO				
Nickel as NiO				
Phosphorus as P_2O_5 - total				
Potassium as K_2O				
Silicon as SiO_2				
Sodium as Na_2O				
Strontium as SrO				
Sulfur as SO_3 - total				
Tin as SnO_2				
Titanium as TiO_2				
Vanadium as V_2O_5				
Zinc as ZnO				

Carbonate as CO_2 - Estimated	
Ignition loss @ 450°C	
Ignition loss @ 900°C	

	PERCENT
Nitrogen, Kjeldahl, as N	
Methylene chloride soluble	
Loss @ 105°C	

pH of ______ % solution/slurry

3486-1 4/81

CALGON ANALYTICAL LABORATORIES
DEPOSIT AND SOLID INORGANIC ANALYSIS

CALGON CORPORATION
SUBSIDIARY OF MERCK & CO., INC.

Received JUL 23 82 Lab No. H3967

COMPOUND/CONSTITUENT IDENTIFICATION

X-Ray Diffraction and Microscopic (Polarized Light)

☐ Analysis performed on methylene chloride extracted sample.

Infrared

Out

From

Plant NORDEN SYSTEMS
Address NORWALK CONNECTICUT

Type of Sample FEEDWATER PUMP LINER
Sample Point ______
Sampling Date ______
Product Used ______

☐ DEPOSIT ANALYSIS ☐ PAPER

Identification (XRF,XRD,Micro)		Elemental Only (XR	
Infrared	Microbiological	Nitrogen	
pH of	Ignition Loss @		
Other			

☑ METALLOGRAPHIC FAILURE ANALYSIS (attach data sheet)
☐ CUT, CLEAN ONE-HALF, ANALYZE DEPOSIT (attach data sheet)

Comments, Special Handling, Etc.

C.C. SID COSTA

FOR CALGON USE ONLY

Field Rep. DAVE WARNER
Mail Drop CENTERBROOK
PJC Charge No. 467
Requested Completion Date

6038 1/8

Sample Pretreatment

______ Liquid removed by filtration ______ Dried at 105°C
______ Extraneous material removed:

______ Microbiological report attached

Reported by:
Approved:
Date:

CALGON
CORPORATION
SUBSIDIARY OF MERCK & CO., INC.

WATER MANAGEMENT DIVISION CALGON CORPORATION SUITE 358 270 FARMINGTON AVE. FARMINGTON, CONN. 06032
(203) 678-1741
(800) 243-5966

May 29, 1980

Mr. Frank Sikorski
Norden Systems, Inc.
Helen Street
Norwalk, Connecticut 06856

Dear Mr. Sikorski:

Listed below are the results of corrosion coupons from your condensate system:

LOCATION	EMMERSION TIME	CORROSION RATE (mpy) STEEL	COPPER
Boiler Room-LP Trap	3/2 to 5/12/80	<0.1	0.0
Fan Room-#7	3/3 to 5/12/80	0.5	0.04
Fan Room-#2A	3/3 to 5/12/80	4.6	0.04

This represents excellent corrosion inhibition by NFL-25 at the first two locations and fair protection at Fan Room-2A. Each deposit has a reddish-black deposit of varying thickness with the greatest on the Fan Room-2A coupons. In addition, some black greasy deposit was noted on two copper coupons.

Based on the above, I am recommending that you establish a new feedrate for NFL-25 of 10 ppm based on steam flow. Monitor condensate pH and if it exceeds 7.8 pH, reduce NFL-25 in 10% increments, so as not to exceed the 7.8 pH. This should continue to give corrosion protection, while minimizing greasy deposits and loosening of old hematite and magnetite that returns to the boiler. In addition, you should investigate Fan Room-2A to determine if condensate contamination exists by hardness and pH testing, and to see if significant air inleakage is occurring.

On April 9, 1980, Dennis showed me the internals of #2 Feedwater Pump, and a sample of deposit was scraped from the cast iron lining for analysis. Attached please find that analysis for your review. It shows the predominance of the deposit consisted of magnetic iron, that could have formed in place or been brought back with condensate. It also has been confirmed that graphitization of the cast iron has occurred. Of the various factors that contribute to this process, only high temperature is certain, and possibly low pH is a factor. Monitoring of feedwater pH will clarify this however. To minimize graphitization and corrosion of bronze impellers, the pH should be at 8.0-8.5. To accomplish this, you can add BL-409 to the deaerating heater thru a separate injection point from sulfite or to the feedwater line prior to the pumps. If BL-409 is mixed with LS-32, the catalyst will be precipitated out in the feed tank and corrosive oxygen pitting will result.

This is not a new problem, in that Dennis brought it to my attention in October 1978. Contrary to the position taken by Roth Pumps, we do not feel that the sulfite is causing the graphitization, as was express in 1978.

As I see it, these options are open for your consideration:

1.) Monitor and control feedwater pH as outlined above.

2.) Continue as is.

3.) Change the feed point of sulfite to the discharge side of the feedwater pumps. In so doing, we feel the oxygen pitting to the feedwater tank, line, and pump, will be more harmful.

4.) Replace these feedwater pumps with models not including cast iron linings.

Very truly yours,

David P. Warner/dr

David P. Warner
Water Management Division

CALGON CORPORATION

DPW/dr
Enclosure

cc: G. Buckley
D. Norden

WATER MANAGEMENT DIVISION CALGON CORPORATION BOX 1346 PITTSBURGH, PA. 15230 (412) 923-2345

...CK & CO., INC.

NORDEN SYSTEMS - NORWALK, CONNECTICUT

LABORATORY NO. B1223
DATE SAMPLED APRIL 9, 1980
DESCRIPTION FEEDWATER PUMP SCRAPINGS
#2 Feedwater Pump - Cast Iron lining scrapings

EMISSION SPECTROGRAPHIC

Element		Major	Low Major	Minor	Low Minor
Aluminum	as Al_2O_3				
Barium	as BaO				
Calcium	as CaO				
Chromium	as Cr_2O_3				
Copper	as Cu			X	
Fluorine	as CaF_2				
Iron	as Fe_2O_3	X			
Lead	as PbO				
Lithium	as Li_2O				
Magnesium	as MgO				
Manganese	as MnO				
Nickel	as NiO				
Phosphorus	as P_2O_5	poor sensitivity			
Potassium	as K_2O				
Silicon	as SiO_2			X	
Sodium	as Na_2O				
Strontium	as SrO				
Tin	as SnO				
Titanium	as TiO_2				
Vanadium	as V_2O_5				
Zinc	as ZnO				X

[X] Standard analysis: 10mg of ashed sample

[ ] ______ mg of ashed / unashed sample

X-RAY DIFFRACTION AND MICROSCOPIC (POLARIZED LIGHT)

MAJOR: Magnetic iron oxide (magnetite)

MINOR: ----

UNIDENTIFIED

Possible constituents: Slight amount of hydrated ferric oxide

Copper and/or iron sulfide

[ ] Analysis performed on solvent ( ) insoluble / ashed @ ______ °C sample.

QUALITATIVE AND CHEMICAL MICROSCOPIC TESTS

Carbonate	N.D.	Metal	
Chloride		Alkalinity	
Phosphate - Inorganic	TRACE	Loss on ignition (~450°C)	1%
Phosphate - Total including organic		Loss on Ignition @ 900°C:	12%
Sulfate	TRACE		
Sulfide	SLIGHT		

KEY TO DATA

Approximate Percentage Ranges for Spectrographic, X-Ray and Microscopic Data

SEMI-QUANTITATIVE TERMS

Term	Spectrographic (Percentage Range)	X-Ray and Microscopic (Percentage Range)
Major	≥ 15	≥ 30
Low Major	8-15	20-30
High Minor	–	15-20
Minor	3-8	8-15
Low Minor	1-3	4-8
Trace	–	1-4

QUALITATIVE TERMS

Term	Percentage Range
Considerable	> 20
Fair	8-25
Slight	1-10
Trace	<1-4
N.D.	Not Detected

QUALITATIVE TERMS MAY BE USED FOR X-RAY AND MICROSCOPIC DATA WHEN JUDGED TO BE MORE APPROPRIATE THAN SEMI-QUANTITATIVE TERMS.

To: Doug Noll
Pittsburgh

From: Dave Warner
Centerbrook, Ct

CALGON CORPORATION
SUBSIDIARY OF MERCK & CO., INC.

SUBJECT Norden Systems – Roth Pumps –
DATE 10/23/78

MESSAGE

Attached is a Roth bulletin for your review. I have been asked to comment on the section on Corrosion on page 4, and would like your comments. Of special interest will be your thoughts on the claim of "sulfate dissolving the iron lattice in cast iron leaving only the carbon particles."

Here is an example (in my opinion) where an equipment mfg is recommending actions which he is ignorant in. How best can we correct this type of problem? Should we be contacting Roth in Rock Is, Ill & educating? Many plant people read such garbage & accept it as gospel!

Your comments please.

Regards & Thanks,

OCT 26 1978

SIGNED Dave

Reply Message ATTENTION OF Dave Warner, Centerbrook, Conn.
DATE OF REPLY 10/26/78

Dear Dave –

I assume these pumps are made of gray cast iron as that is the only type of material that suffers from graphitization in this type of service. Based on experience, I do not believe sulfite contributes to the graphitization of gray cast iron. Uhlig says salt water and acid solutions cause graphitization and that sulfate may if cast iron is buried in soil containing sulfate. That is the only reference I can find to sulfur bearing compounds. Tell the customer SO_3 in cast iron pumps is not a problem.

Concerning the question in your 10/18/78 Activities Report for Upjohn, the $CaCl_2$ brine will have some effect on the inhibiting properties of H-168, but it is minimal. I suggest you double the inhibitor concentration while the brine is in the system.

SIGNED Doug

FORM NO. 3406 B

RECIPIENT

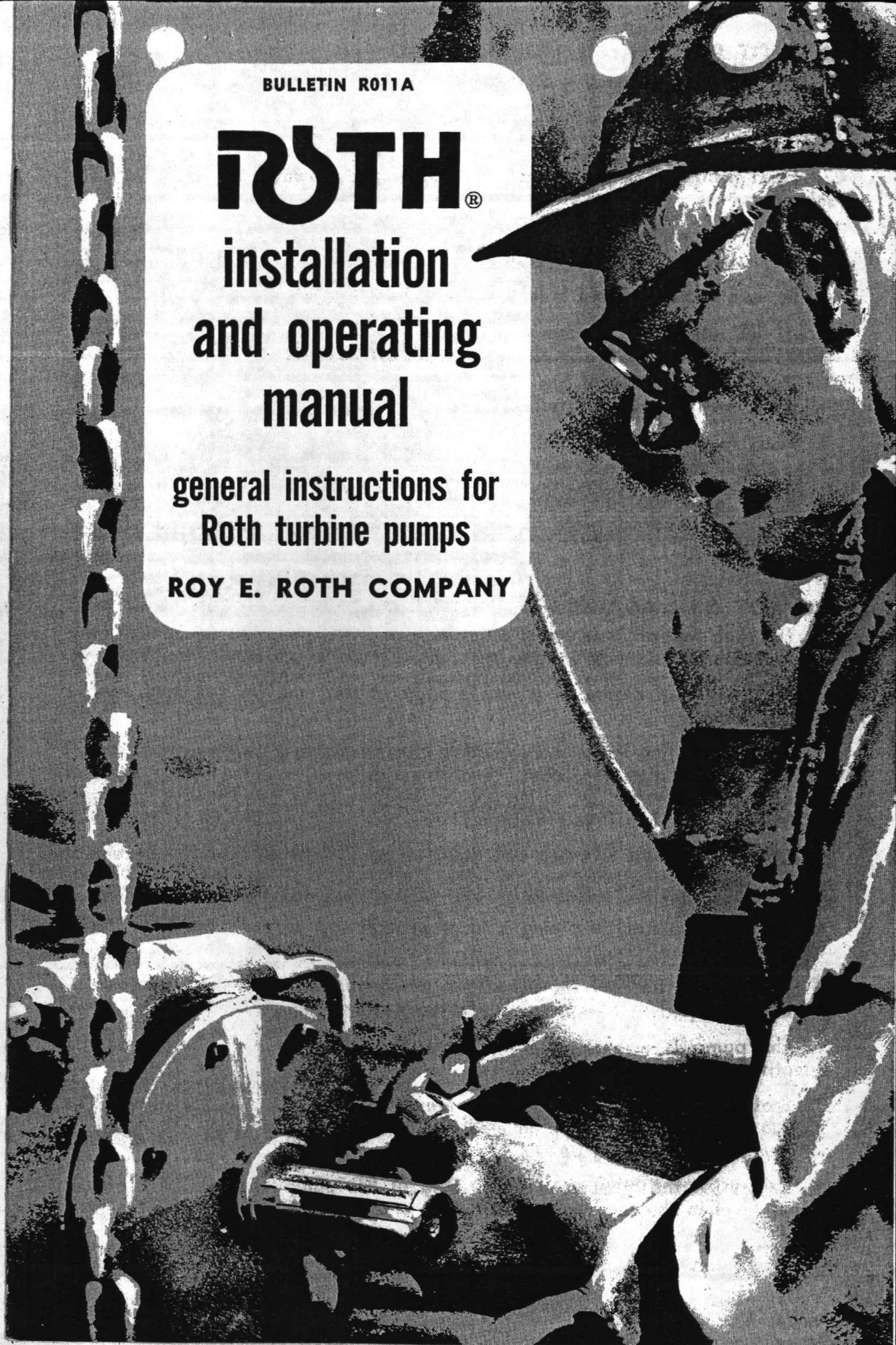
BULLETIN R011A

ROTH®

installation and operating manual

general instructions for Roth turbine pumps

ROY E. ROTH COMPANY



DO NOT RUN UN[illegible]S LIQUID FILLED.
Any mechanical seal or packing will heat from dry run.

1. Heat at the seal or packing can damage the sealing surfaces and cause the pump to leak.

2. Heat from seal or packing dry run can expand the shaft and cause impeller seizure.

3. Make sure suction lines are full open and a steady supply of liquid is available.

4. Be sure suction piping is large enough and properly installed.

PROTECT PUMP INTERIOR AGAINST LARGE HARD SOLIDS.

1. The pump as shipped has closures in suction and discharge. Leave these in place until ready to install.

2. Flush the suction line piping thoroughly before installation to remove any slag, chips, or dirt.

3. Install a suction line strainer to screen large particles (use 100 mesh or finer). Use temporary plate strainer at flanged joint if Y, L, or basket strainer not specified.

DO NOT RUN AGAINST CLOSED DISCHARGE VALVES.

1. The high shut-off pressure of a turbine pump is beyond the mechanical limit of the pump at 3500 RPM. Damaged shaft or impeller can result from overload.

2. Make sure all discharge piping is open at start-up. Do not start against closed valves.

3. If a modulating valve is installed in the discharge, a by-pass valve should be installed for pressure relief. A pressure differential valve should be used on continuous service. A spring loaded by-pass valve can be used on intermittent service. See Figure 6, page 11.

4. Check all valves to make sure yoke, stem, and valve face are connected.

5. Examine all check valves to make sure flow is in the proper direction.

6. Make sure discharge piping is large enough and properly installed.

Do not run on boiling liquids unless specifically designed for this service.

1. Boiling liquids can vaporize inside the pump causing dry run.

2. The pump is essentially a liquid handling machine and will not handle quantities of gases.

3. Protect against boiling liquids by elevating the suction supply vessel. The suction pressure created by an elevated receiver usually keeps the liquid at the pump below boiling point.

4. Determine the minimum NPSH rating of the pump and set the minimum liquid level in the receiver at this height or more above the pump.

5. For [illegible]uids just below boiling this height can b[illegible]duced approximately 0.6 ft. for each degree F below boiling in the receiver.

6. Do not restrict or valve the suction line when pumping near boiling or boiling liquids. This would create a partial vacuum which would lower the boiling point and cause the liquid to flash and the pump to run dry.

GUARANTEES

A general guarantee or warranty is the factory's pact with the user to assure him of equipment of good quality.

Where certain operational hazards beyond the user's control exist the factory attempts to develop special features for special protection and issues special guarantees.

GENERAL GUARANTEE

All Roth pumps are guaranteed for one year from date of installation up to 18 months from date of shipment against defects in workmanship or material. This means the user or contractor has six months to install and start the equipment and 12 months after start to discover anything that might escape the factory inspectors' tests.

Not much does but if it should happen the guarantee is there.

It should also be clear that the guarantee does not cover damage in shipment, damage in installation, or damage due to solid particles or dry run after start-up.

ACCESSORY EQUIPMENT GUARANTEES

The electrical equipment is covered by the guarantees of the original manufacturer and is extended through Roth by agreement to the contractor or user.

In the event of motor, switch, or control malfunction the contractor or user has the option of calling the Roth factory, salesman, representative or distributor, or going direct to the electrical manufacturer or his authorized representatives or repair stations.

Caution: In the event of electrical trouble do not authorize electrical repairs by an unauthorized repair station. In most cases you will not be compensated for such expense. Call us or locate the nearest authorized repair station before incurring expense.

SPECIAL GUARANTEES

Roth has developed two special feature guarantees to protect the user against damage beyond his control.

1. SHAFT GUARANTEED FOR TEN YEARS AGAINST BREAKAGE IN RECOMMENDED SERVICE.

The unusual loads of both pumps, especially at high pressures, has led us to design shafts far beyond the size and weight needed for normal usage. Because of this extra value the pump will be repaired free of charge at the factory if the shaft breaks in recommended service within 10 years of date of shipment.

2. Boralloy lined pumps are guaranteed against all forms of feedwater corrosion for a period of two years from date of installation. This guarantee only applies to Boralloy lined pumps and only applies to boiler feedwater or condensate return service.

CORROSION

Other than the Boralloy guarantee above no corrosion guarantee is offered except that implied under the general guarantee.

In effect Roth guarantees that the pump will be made of good quality material as specified but does not accept the responsibility for the corrosion rate in various liquid environments.

The contractor or user should protect the pump against damage by corrosion by taking care that no strong chemicals or solutions other than those specified are allowed to contact the pump interior.

Many boiler feed compounds contain alkali or ammonia which go into solution and attack the bronze parts in bronze fitted boiler feed pumps. The amine compounds which release ammonia in solution can also cause trouble in the condensate return pumps since the ammonia will carry over with the steam and dissolve in the returning condensate.

Some compounds are selected as oxygen scavengers such as sodium sulphite. Unreacted sodium sulfite in solution can dissolve the iron lattice in cast iron leaving the carbon particles only.

Because of these and other hazards boiler feed compounds should be introduced into the boiler through a by-pass feeder in the pump discharge line or through separate chemical feed pumps direct to the boiler.

The occasional practice of introducing chemical compounds to the receiver tank or the deaerator almost always results in premature pump failure due to corrosion and should be avoided. Pumps damaged by feedwater chemicals, other than Boralloy lined, will not be covered by warranty.

In general all bronze pumps are required for brine or salt water applications, and all iron pumps are required for alkali wash solutions. The selection of the proper material of construction should be agreed upon by the manufacturer and the contractor or user at the time of purchase.

Corrosion of pumps in brine or alkali wash service is not protected by warranty.

BALL BEARINGS

Roth guarantees that only ball bearings by the best manufacturers using the most advanced inspection and laboratory techniques are used.

Roth also guarantees that the bearings are installed with interference or slip fits in accordance with the bearing manufacturers' published recommendations and tolerances. For instance all shaft journals under ball bearing inner races are ground on centers to tolerance of plus .0002 inches minus nothing.

Roth also guarantees that all ball bearings are kept in closed and sealed containers until ready for assembly so that the lubricant or surfaces will not be contaminated with dirt or corrosion.

In order to obtain maximum life from the bearings the user or contractor should take steps to insure that only clean, uncontaminated lubricants are used. In greasing bearings remember that over-greasing is harmful. If the grease goes in against resistance something is wrong.

TESTS

Every Roth pump shipped from the factory is pressure tested for leaks, and is given a running test for capacity and head. The test records are kept on file against the sales order.

In addition pumps running slightly over capacity are checked for power input against specified limits so that motors will not be overloaded.

Finally all pumps for hot water service and all process pumps are heated to 240°F to check against binding due to expansion and contraction in service.

INSTALLATION

Unless the order specifies doweled pump and motor, alignment of flexible coupled pumps at the factory operates only as proof that all dimensions are proper relating to relative height and spacing of pump and motor.

The factory cannot control either misalignment due to rough handling in shipment or misalignment due to tension of mounting bolts or studs or pipe strain.

IT IS ESSENTIAL THAT THE CONTRACTOR OR USER REALIGN THE PUMP AND MOTOR AFTER THE UNIT IS SECURED IN PLACE.

SETTING THE UNIT

The base of feet must be set on a solid foundation that will not flex or relocate. A concrete base is usually required. This should be smooth and level with provision for bolting the unit down at the proper points.

Bolt the unit down before connecting the pipes using a level and wedges to minimize misalignment. Place unit on the foundation and drive wedges under edge of bed plate until even support is secured. Any misalignment now apparent usually involves shimming the pump or driver or both until the cylindrical surfaces of the coupling halves are within roughly .005 inch parallel *and* ½° angular alignment. The most commonly used tool for checking alignment is a straight-edge and the amount of misalignment is usually gauged by eye.

To check alignment, place a straight-edge across the coupling. The straight-edge should be in full contact with both rims at the top, bottom and sides. Grouting should then be poured under the bed plate and permitted to set perfectly before pulling down on the foundation bolts. Refer to Figure 1.

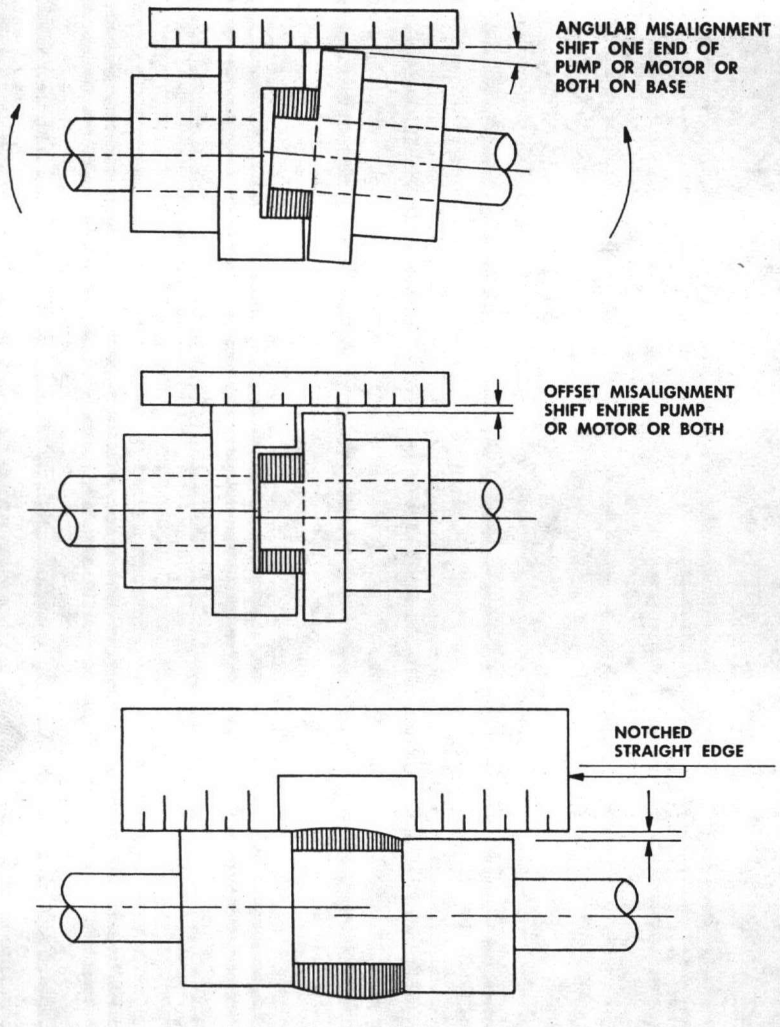


FIGURE 1

PIPING

Suction and discharge pipes must line up and not be forced into position when assembling to pump. All piping must be supported to insure that no stresses or strains are transmitted to the pump. Whenever possible flexible connections should be used in connecting piping to both the suction and discharge connections of the pump.

In the case of screwed connections the suction piping is connected to the pump by means of a short nipple screwed into the pump connection and a union assembled on the other end of the nipple. The discharge piping is similarly connected to the pump with a nipple and a union installed in the downstream side between the pump and any other fittings such as gate valves or check valves. In the event it becomes necessary to work on the pump in the future, it can be removed from the line quite readily and put on a bench where it will be easy to work.

CAUTION: A little extra time should be spent making sure all pipe lines up naturally and all connections touch before tightening flange bolts or unions.

Poorly fit piping has been known to break cast iron suction or discharge nozzles. Even if it doesn't cause breakage pipe strain can cause coupling misalignment, binding impeller, or hot bearings.

PIPING TEST CONNECTIONS

There will always be occasions when properly selected pumps in first class condition will fail to deliver the desired performance. In such circumstances operating and maintenance people must use good judgment and carefully test for the causes of failure.

The last thing to do in this situation is to remove the pump from the line and dismantle it to look for a mechanical cause. Ordinarily the factory assembled pump is carefully adjusted to deliver the performance required.

The first thing to do is to use the factory assembled pump as a measure of the conditions of operation. Assume that something unforseen in the conditions of operation is the cause of failure. **Look for the unknown operating condition.**

The best thing to do is to install test connections in the line at the time of installation. In the event of trouble this can save hours and sometimes days. The following are recommended:

1. Suction head or suction lift

A pipe tee with plug should be in stalled in the suction line near the pump suction. In the event of poor performance a compound gauge should be installed in this tee and readings taken when the pump is idle and also when the pump is running at various discharge pressures.

2. Temperature

Some means of taking liquid temperature near the pump should be provided. Temperature near the pump at low pumping volumes is sometimes cooler on hot liquids or warmer on cold liquids than at the suction vessel. It is important to know temperature at the pump to determine the vapor pressure of the liquid when it enters the pump.

Another pipe tee in the suction line is suitable. Many Roth pumps have a 3/8" tapping in the suction nozzle which can be utilized.

3. Discharge pressure

A tee should be installed near the pump in the discharge line to measure the pressure developed by the pump. It will also be desirable to have a gate valve in the line downstream of the pressure gauge to restrict the flow and measure pressure at various settings. Many Roth pumps have a ⅜" tapping in the discharge nozzle which can be utilized.

4. Pump capacity

Some means of measuring pump capacity should be provided. Process plants usually install flow meters or recording instruments for this purpose.

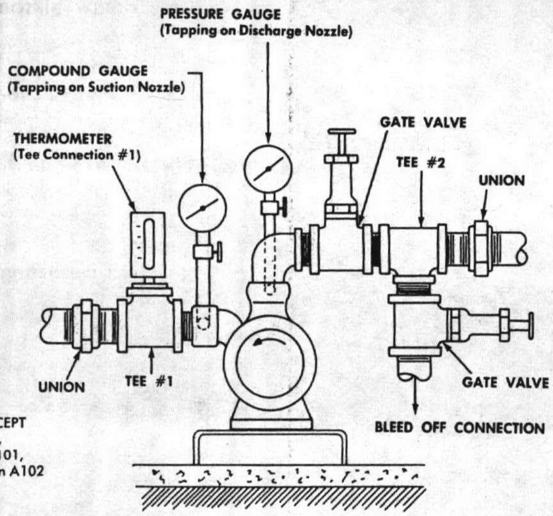
These types of instruments are usually too expensive for condensate return or boiler feed units. However another tee can be installed downstream of the regulating valve with a gate valve and drain connection so that the entire flow can be pumped into a five or ten gallon pail. The pump capacity at various pressures can be measured by measuring the time required to fill the container.

If the suction and discharge lines are equipped with these connections and complete readings taken the cause of failure can be easily determined. One or two of three answers are possible:

1. The pump is performing according to catalog or quotation.
2. The pumping conditions do not conform with the specification.
3. The pump does not perform according to catalog or quotation.

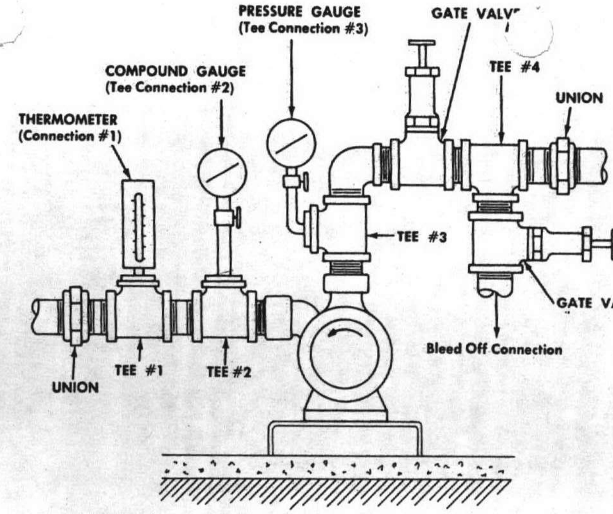
The pump should be removed for examination only if all factors point to (3) as the answer.

See Figures 2 & 3 for suggestions as to test connections in suction and discharge lines.



ALL ROTH PUMPS EXCEPT
10 Series in Section 101,
U10 Series in Section M101,
and 200 Series in Section A102

FIGURE 2



10 & 200 SERIES PUMPS

FIGURE 3

STUFFING BOX ON PACKED PUMPS

During factory testing the gland on packed pumps is tightened to prevent excessive leakage and may not be properly adjusted for ultimate installation. Loosen the packing gland until there is no pressure on the packing before starting. Tighten later according to start-up instructions.

WIRING

All wiring should be done in accordance with local code or power company regulations. Single phase fractional horsepower motors shipped from the factory are equipped with built-in thermal protection. All other motors, including single phase integral horsepower and all three phase motors, should be provided with some kind of overload protection. All three phase motors should be equipped with across-the-line magnetic starters.

STARTING AND OPERATING

Observe the following in starting pump the first time:

1. Turn over by hand to make sure the shaft-impeller assembly is free from binding.

2. Check alignment to make sure it has been properly aligned.

3. Make sure discharge line is open. DO NOT START PUMP AGAINST A CLOSED DISCHARGE VALVE.

4. Be sure valve in suction line is open and there is liquid in suction vessel and pump.

5. Allow pump to come up to the operating temperature of the liquid, if it is above ambient, by jogging pump with starter.

6. Be sure pump is rotating in the proper direction. Refer to rotational arrows on pump body.

7. After pump is sta[illegible], adjust packing gland for proper pressure. [illegible] no time should you attempt to stop all leakage from a packed stuffing box. Minimum leakage of six drops per minute is required to lubricate the shaft properly. Sixty drops per minute should not be considered excessive. Adjust packing only when pump is running.

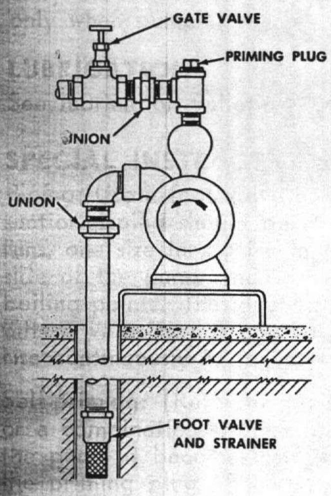
LUBRICATION

See lubrication Bulletin R012A for instructions and lubricant.

SPECIAL INSTRUCTIONS

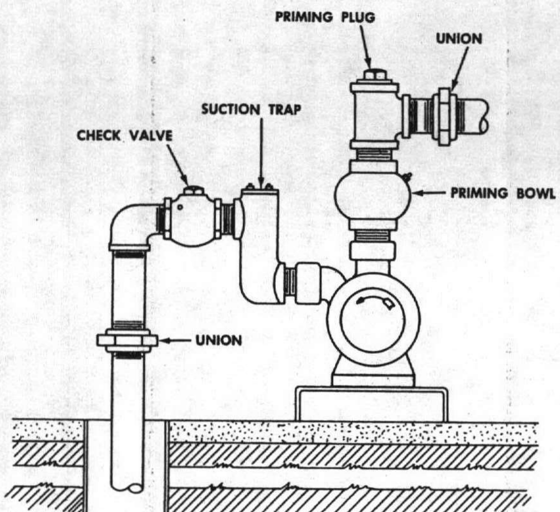
Piping: Use a foot valve or check valve in the suction line for suction lift. The suction piping should be at least the size of the suction connection for short runs, one size larger for long runs. This is especially important on the suction side of the pump and with liquids which are being pumped at or near their boiling points. The ideal size for the suction pipe handling boiling liquids permits a velocity not greater than 4.0 feet per second. Suction piping should rise continuously to the pump without back loops.

Self-priming: (Refer to Figures 4 & 5) When a suction trap and check valve, or a combination strainer and check valve, are installed in the suction line of the pump it becomes self-priming after filling with water. To prime, remove the priming plug. Pour enough water into pump through the opening to fill the pump and the suction trap. Replace the plug and turn pump over by hand to see that it is free. Jog the pump to check for proper direction of rotation. Turn on current and pump will remove the air from the suction line and pick up its prime. The length of time required to do this depends upon the size and length of the suction line. The suction line must be bubble tight. It will not be necessary to reprime unless there are leaks in the suction line. It is advisable to remove the strainer screen periodically for cleaning.



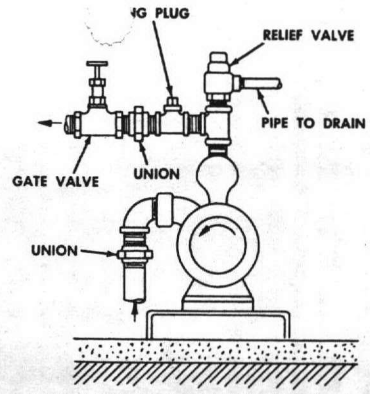
INSTALLATION WITHOUT SELF PRIMING ATTACHMENT

FIGURE 4



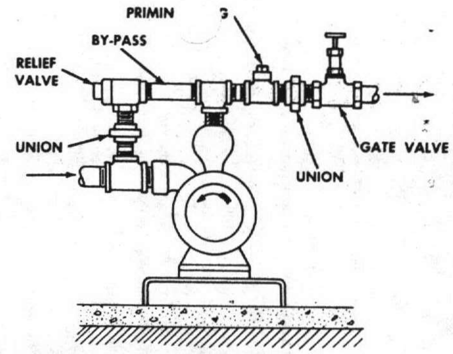
INSTALLATION WITH SELF PRIMING ATTACHMENT

FIGURE 5



INSTALLATION WITH RELIEF VALVE IN DISCHARGE

FIGURE 6



INSTALLATION WITH RELIEF VALVE BETWEEN DISCHARGE AND SUCTION

FIGURE 7

Relief Valves: The installation of a suitable relief valve in the discharge line is recommended if it is possible to close valves in the discharge line against a running pump. Figure 6 shows a relief valve installation for ordinary excess pressure protection. Figure 7 shows relief valve installation in the by-pass between discharge and suction for use ONLY on liquids which are well below boiling point.

Notice: Boiler feed and condensate pumps only:

Only vessels specifically labeled with ASME code stamp may be installed for storage of steam. Most receivers provided for condensate return or boiler feed service are intended as water storage vessels only and do not carry code stamps. These receivers must be piped with unobstructed vent to atmosphere.

The manufacturer of boiler feed and condensate return units must rely on the installer to observe all plumbing and piping codes in connecting. The following check points to insure against unsafe introduction of steam pressure should be observed:

1. Returning condensate should be trapped to maintain temperatures below 210°F.

2. The receiver should be piped with an unobstructed vent to atmosphere.

3. Operators who notice steam loss through the atmospheric vent should never close the vent to conserve steam. This will result in steam pressure inside the vessel and create risk of explosion with hazard to life and property. Steam loss through the vent must be eliminated by control of nontrapped drainage to the vessel.

4. The use of perforated tube heaters is not recommended in atmospheric receivers.

5. Positve protection against overpressure is provided by Roy E. Roth Co. by a blow-out plug installed in all atmospheric vented receivers to provide relief in case of obstructed or accidentally plugged vents. Do NOT replace this plug with any substitute item; contact Roy E. Roth Co. for free correct replacement.

ROTH®

installation and operating manual

Roth turbine pumps are made with care and precision. This information is provided for the maintenance people who want to preserve that quality on which the performance depends.

REPAIR MANUALS AVAILABLE

R101A — Head Repair Packed — Industrial Pumps
R101B — Head Repair Sealed — Industrial Pumps
R101C — Frame Repair — Industrial Pumps
R101D — Seal Replacement — Industrial Pumps

R102A — Fractional HP Pumps — 1750 RPM Repair
R102B — Fractional HP Pumps — 3500 RPM Repair
R102C — Close Coupled Pump Repair
R102D — Vertical Condensate Pump Repair
R102E — Vertical Condensate Pump Moderization

ROTH®

THE ROY E. ROTH COMPANY
TURBINE PUMP DIVISION
ROCK ISLAND, ILLINOIS 61201
PHONE 787-1791 AREA CODE 309

Printed in U. S. A.

Ed

March 26, 1969

Cincinnati Gas & Electric Company
P. O. Box 960
Cincinnati, Ohio 45201

Attention: Mr. L. W. Gleason
Superintendent of Electric Production

Walter C. Beckjord Station
New Richmond, Ohio

Gentlemen:

Attached is a copy of the metallurgical report for the failed primary superheater tube removed from the No. 4 Combustion Engineering boiler on February 25, 1969. I believe that you will find the report self explanatory, but should you have questions please contact either our Cincinnati Office or me here at Calgon Center in Pittsburgh.

Very truly yours,

CALGON CORPORATION

R. E. Elliott
Consulting Engineer

REE/bal

cc Mr. N. J. Krebs (Enclosed)
cc Mr. Paul Hoffmeier
cc Mr. E. E. Galloway
cc Mr. J. B. Kearney

cc Cincinnati
cc Hall-Cincinnati
cc R. E. Elliott
cc Hall File

REPORT OF METALLOGRAPHIC EXAMINATION
Laboratory Nos. Y-6851 and Y-6852
Samples Received March 4, 1969

Sample Y-6851 contained part of the failure and is shown in the macrophoto, Figure 1 - Fractured Superheater Tube. This failed tube was identified as the eleventh tube on the south side of the boiler in the top row of the primary superheater. The second tube section examined by us, Y-6852, was removed from the same superheater element approximately ten feet from the failure. Specifications for the superheater indicated that this tube should be T-11 steel, but chemical analysis showed only 0.09% chromium rather than the 1% to 1.5% chromium required for T-11. The molybdenum was found to be 0.54% which is within the 0.44% - 0.65% required for T-11.

Metallographic samples were taken from the fractured section and from the unfailed section of the same tube. These samples were mounted, polished, etched, examined under the microscope, and then subjected to photomicroscopy.

Figure 2 is a photomicrograph of the O.D. cross section near the fracture while Figure 3 is a photomicrograph of the I.D. cross section near the fracture. These photomicrographs (Figure 2 and Figure 3) reveal surface pitting and decarburization. Figure 4 is a photomicrograph of the structure in the middle of the tube wall near the fracture and shows spheroidization which is an indication that the steel was heated to a temperature of approximately 1300° F.

Figures 5 and 6 are of cross sections of the tube sample, Y-6852, some ten feet from the failure and indicate approximately the same structures as Figures 2 and 3, respectively, except the surface pits or crevices are missing.

Based on the above observations, it is evident that the tube is not T-11 steel but is a 0.5% molybdenum steel. The tube was apparently overheated as is indicated by the spheroidized structure and the decarburization. Final parting of the tube is attributable to stress rupture. The tube weakened by surface crevices, decarburization, and its operation above a useful temperature range succumbed to the applied internal pressure of 2475 psi, which constitutes a stress in excess of 8000 psi on the reduced wall.

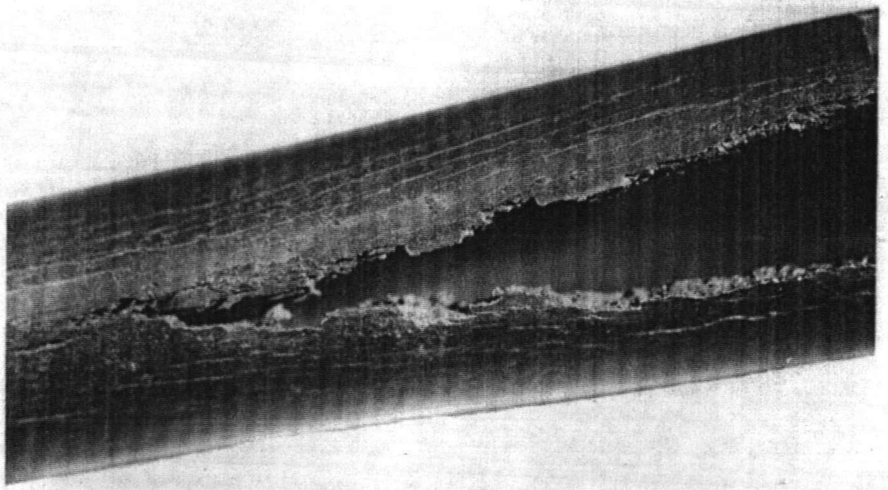


Figure 1

Fractured Superheater Tube - 2" Diameter X 0.320" Wall

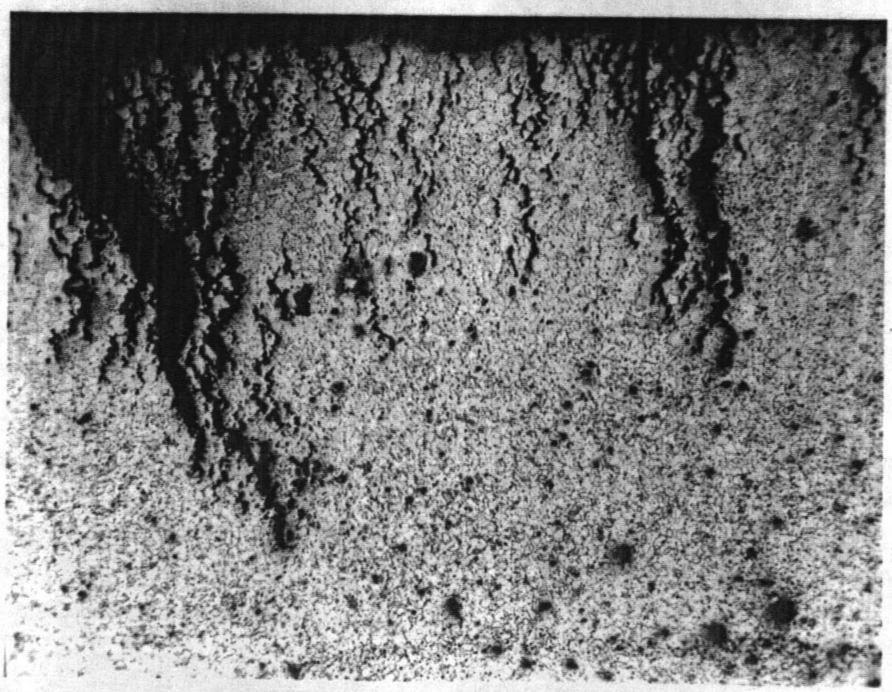


Figure 2

O.D. Cross Section Near Fracture 50X

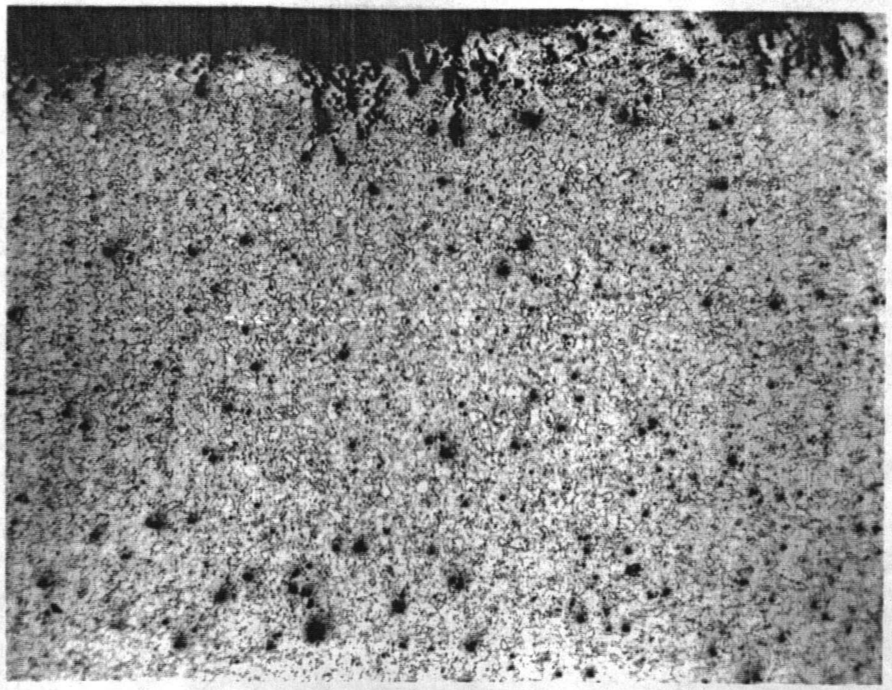


Figure 3

I.D. Cross Section Near Fracture 50X

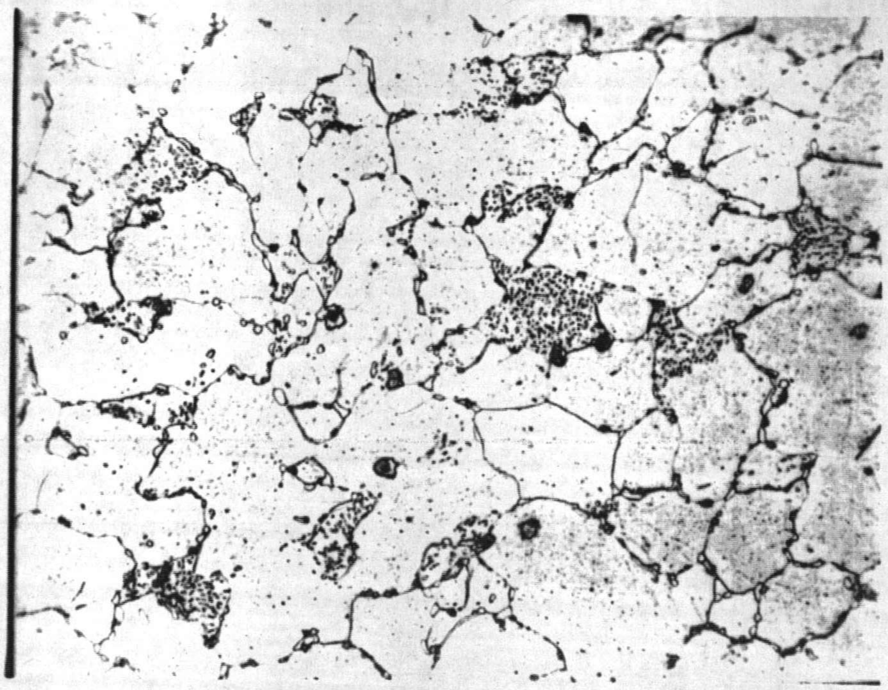


Figure 4

Microstructure in Center of Tube Wall
Near Fracture 1000X

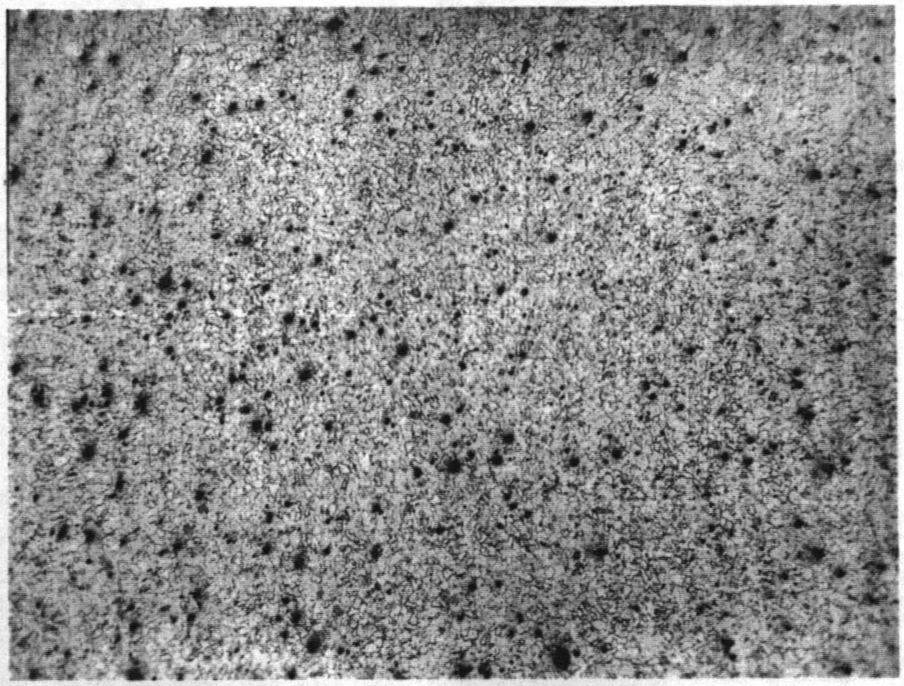


Figure 5

O.D. Cross Section Away From Fracture 50X

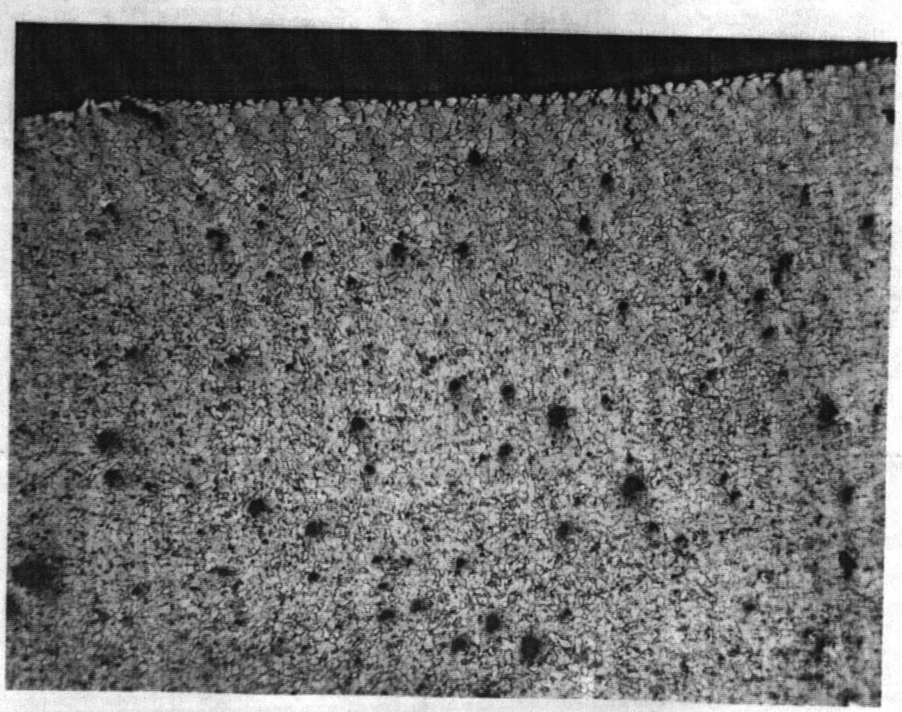


Figure 6

I.D. Cross Section Away From Failure 50X

Dissimilar-metal weld failures in boiler tubing

Increased cyclic operation of boilers has led to a rash of failures in welds between dissimilar metals; studies have identified the causes, and improved nondestructive testing techniques permit early identification of problem areas

By R. L. KLUEH, Metals and Ceramics Division, Oak Ridge National Laboratory

Both ferritic heat-resisting steels and austenitic stainless steels are used for fossil-fired boilers for central power stations. Primary boilers and heat exchangers operate at temperatures and environmental conditions that make the low-alloy chromium-molybdenum (Cr-Mo) ferritic steels the best choice for the structural material. Superheaters, reheater tubes, and the hot-reheat steam pipes operate at elevated temperatures where austenitic stainless steels become the necessary choice. The use of these two different types of materials within the system leads to the need for a dissimilar-metal weld transition joint.

The problems inherent in such dissimilar-metal weld joints have long been recognized and various "fixes" have been applied. With the increasing trend in recent years toward two-shift operation (on-load for 16 hours with an 8-hour overnight shutdown), the utility industry has experienced a rash of transition-joint weld failures in fossil-fired steam plants. Because of the growing concern these failures were causing the industry, the Steam Power Panel of the ASTM/ASME/MPC (American Society for Testing and Materials/American Society of Mechanical Engineers/Metal Properties Council) Joint Committee formed a special task group in 1977 to study the problem and make recommendations for solutions.

Extent of problem

One of the first actions of the group was a questionnaire that was submitted to U.S. utilities seeking information on utility experience with dissimilar-metal weld failures. The results of that survey indicated the widespread nature of the problem. Fifty-four utilities responded, and of a total of 320 generating units reported on, failures had been experienced in 60. Failures had occurred in fusion welds using three types of filler metal, in induction pressure welds, and in electric-resistance welds. The failures were broken down as follows: 38 fusion welds with austenitic filler metals, 10 fusion welds with ferritic filler metals, 7 fusion welds with high-nickel filler metals, 4 pressure welds, and 1 electric-resistance weld.

Boilers contain heat-absorbing and nonheat-absorbing joints, and failures occurred in both types. Failure times ranged from 29,000 to 125,000 hours of operation. In the nonheat-absorbing joints, the mean time to failure was 91,000 hours, and in the heat-absorbing joints it was 74,000 hours. Thirty-seven percent of the reported failures occurred after 100,000 hours of operation; 76% of the failures reported were in the superheater region. The survey clearly indicated a large incidence of dissimilar-metal weld failure long before the lifetime of the boiler tubes had been exhausted.

Since the original survey was conducted, the task group has received a large number of additional reports from utilities that have experienced the problem. The task group has also had participation from representatives of utilities from other countries, including Canada, England, Japan, and Holland. Utilities in all of these countries reported problems similar to those in the United States.

The economic consequences of tube failures were estimated in an Electric Power Research Institute (EPRI) report, where it was stated that boiler-tube failures are a major cause of boiler outages (Ref. 1). The authors estimated that tube failures account for a 4% annual loss of availability in the United States. A 1% improvement in availability of coal plants nationwide over a five-year period would be valued at $1.2 billion.

Nature and cause of failures

As a result of the widespread nature of the problem and its economic consequences, the ASTM/ASME/MPC task group established a program to determine the cause of the problem and develop a solution. This program, which is funded by EPRI, is presently in place at GA Technologies in San Diego and at Combustion Engineering, Inc. in Chattanooga. The program is designed to eventually develop an improved dissimilar-metal weld. To do that a laboratory test procedure is being developed to simulate service failures on an accelerated basis. In addition, "improved" welds are being placed in boilers where they will be periodically removed and examined.

The failures being discussed here occur in the heat-affected zone of the ferritic steel very near the weld fusion line. Most service failures have occurred with 2¼ Cr-1 Mo steel tubing (T-22) as the ferritic alloy—primarily because most fossil-fired power plants are constructed with this widely used Cr-Mo steel—although other Cr-Mo steels are sometimes used and also fail [e.g., 1¼ Cr-½ Mo (T-11), 5 Cr-½ Mo (T-5) and 9 Cr-1 Mo (T-9)]. Various austenitic stainless steels are in service in power plants; these include types 304, 316, 321, and 347 stainless steels. Because failure occurs in the ferritic steel, the stainless steel will not be further discussed.

The microstructure of a typical dissimilar-metal weld failure between 2¼ Cr-1 Mo steel and type 316 stainless steel steam pipes welded with the high-nickel ENiCrFe-1 (Inconel 132) filler metal that failed after more than 17 years (about 150,000 hours) of service is shown in Figure 1. It is a low-ductility failure that occurred in the 2¼ Cr-1 Mo steel near the fusion line (Figure 1b). For all such failures made with high-nickel filler metals, several distinct microstructural features are observed in the 2¼ Cr-1 Mo steel near the fusion line. A row of precipitate particles forms in the grain boundaries of the 2¼ Cr-1 Mo steel parallel to the fusion line about 10-15 μm from the fusion line (about one grain width) (Figure 1c), and although not found in the microstructure of Figure 1, microvoids occasionally form in conjunction with the grain boundary precipitates. The crack propagates along these grain boundaries parallel to the fusion line.

Failures in fusion welds made with an austenitic stainless steel filler metal, such as type 309, or failures of induction-pressure welds at first glance often appear to be somewhat different from failures in fusion welds made with high-nickel filler metals. However, on closer inspection, common features are found for each weld. For a type 309 stainless steel weld, no line of grain boundaries forms parallel to the fusion line. Nevertheless, the grain boundaries in the vicinity of the fusion line contain relatively large precipitates, and the fracture propagates through these grain boundaries. Because the grain boundaries make various angles with the fusion line, the intergranular crack often proceeds by a more tortuous route com-

pared to the crack in a high-nickel weld.

A still more complicated precipitate structure occurs in an induction-pressure weld. However, the failure again occurs by a crack propagating in the 2¼ Cr-1 Mo steel about one grain width from the fusion line. An example of such a failure is shown in Figure 2a where the tube appeared to have come apart because of a bad weld. On closer examination, a surface layer of 2¼ Cr-1 Mo steel grains was found to be adhering to the type 347 stainless steel side of the failed weld (Figure 2b).

Problems have been experienced with dissimilar-metal welds ever since they were introduced. Factors that contribute to joint failures in fossil-fired plants have long been discussed (Ref. 2). They include: (1) cyclic thermal stresses, (2) low oxidation resistance of the low-alloy ferritic steel, (3) carbon migration, and (4) metallurgical deterioration caused by elevated-temperature exposure. The importance of each of these in causing failure is still a subject of debate.

During power plant operation, numerous start-ups and shutdowns generate thermal stresses within the joint. These cyclic stresses superimposed on the residual welding stresses, external loads, and internal steam pressure are believed to be the ultimate cause of the failure.

Although it has generally been thought that a cyclic stress is required to produce this type of dissimilar-metal weld failure, several investigators have produced such failures in a creep-rupture test. It is agreed, however, that in an operating steam plant the stresses due to thermal cycling when the plant is started and stopped are important to dissimilar-metal weld failure.

In a test program in the 1950s, Tucker and Eberle (Ref. 2) found that under cyclic stress, the absence of oxygen (pure helium atmosphere) deterred failure. Typical fractures occurred when tests were carried out in helium with small amounts of oxygen. Furthermore, cracks that form during service or those simulated in the laboratory are usually highly oxidized. Tucker and Eberle concluded that the relatively high oxidation rates for the ferritic steel could give rise to oxide notches that ultimately lead to failure.

Metallurgical factors

Carbon migration and subsequent decarburization of the low-alloy ferritic steel are the result of the difference in carbon solubility in the weld metal and ferritic steels. During welding and elevated-temperature service, carbon is transferred from the ferritic steel to the weld metal by diffusion. This leads to a decarburized zone in the ferritic steel, which causes a decrease in the strength of the ferritic steel compared with this same steel having a normal carbon composition.

Metallurgical deterioration occurs in

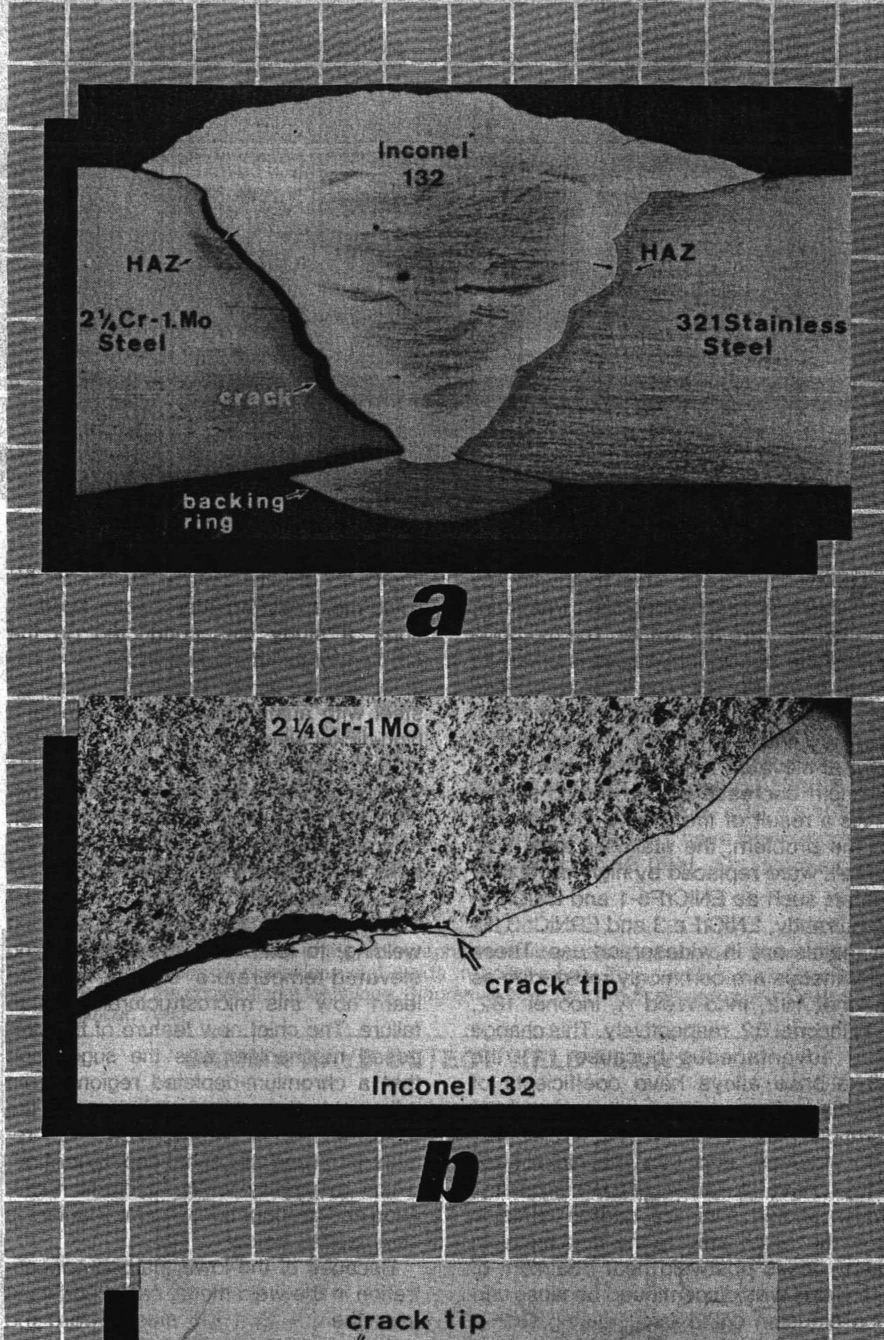


Figure 1. Photomicrograph of a failed dissimilar-metal weld joint (a) showing a cross section of the joint (magnification 3x), (b) at higher magnification (50x) showing that the crack propagates in the ferritic steel very near the fusion line, and (c) at a still higher magnification (3000x) showing how the crack propagates through a grain boundary that contains carbide precipitates.

a,b

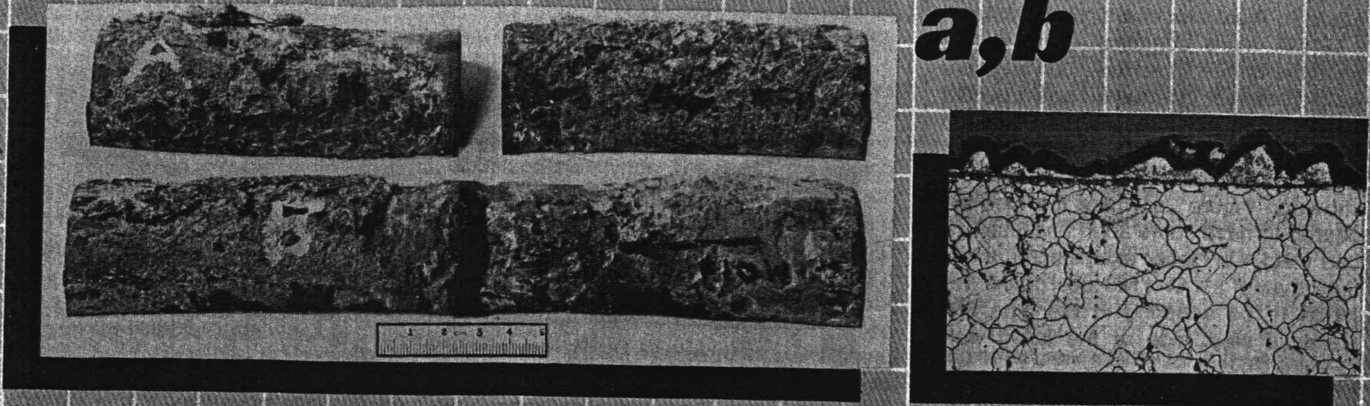


Figure 2. Photograph of a failed and unfailed induction-pressure weld between Type 347 stainless steel and 2¼ Cr-1 Mo steel, and (b) photomicrograph of cross section of fracture surface showing grains of 2¼ Cr-1 Mo steel adhering to the type 347 stainless steel (100x). The adhering grains indicate that the crack propagated in the 2¼ Cr-1 Mo steel about one grain width from the fusion line.

the low-alloy ferritic steel because the carbides that form during heat treatment and welding are not stable. The morphology of the equilibrium carbides in ferritic steels is usually such as to be much less effective in strengthening the material than are those originally present. Exposure at elevated temperatures leads to a strength decrease for the ferritic steel.

As a result of the early understanding of the problem, the stainless steel filler metals were replaced by high-nickel filler metals such as ENiCrFe-1 and ENiCrFe-2; currently, ENiCrFe-3 and ERNiCr-3 filler metals are in widespread use. These filler metals are commonly referred to as Inconel 132, Inco-Weld A, Inconel 182, and Inconel 82, respectively. This change was advantageous because (1) the nickel-base alloys have coefficients of thermal expansion closer to those of the ferritic steels, thus lowering cyclic thermal stresses, and (2) the nickel-base alloys have a lower carbon solubility, which should minimize carbon diffusion from the ferritic steel to the weld metal. In many cases postweld heat treatment of the welds was discontinued because carbon diffusion could occur during such a high-temperature heat treatment and accelerate failure. Although the use of the high-nickel filler metals increases the lifetime of the joints, they nevertheless fail, as seen in Figure 1.

The microstructural features of the 2¼ Cr-1 Mo steel near the fusion line are quite complicated. Early investigators spoke of a "decarburized zone" in the vicinity of the fusion line. They felt that thermal stresses in the ferritic steel near the fusion line could reach the yield strength and lead to failure in the region of reduced strength because of carbon diffusion. Later work provided refinements in these observations; interest was focused on the various phases and precipitate zones that could be resolved at high magnification.

In conjunction with studies at the Oak Ridge National Laboratory to develop an improved dissimilar-metal weld joint for liquid metal fast breeder reactor applications, a study was conducted on the problem of joints made with 2¼ Cr-1 Mo steel welded to an austenitic stainless steel with austenitic stainless steel and high-nickel weld filler metals (Ref. 3). A large number of failed and unfailed joints were examined metallographically; metallographic studies were also made on as-welded specimens. These observations were combined with previous results to develop a mechanism by which the interface microstructure forms during welding, to learn how it evolves during elevated-temperature service, and to learn how this microstructure leads to failure. The chief new feature of the proposed mechanism was the suggestion that a chromium-depleted region forms adjacent to the grain boundaries near the fusion line. This chromium-depleted region is prone to enhanced oxidation, which eventually leads to crack nucleation and propagation. The mechanism is summarized below.

Because of the lower carbon concentration in the weld metal, carbon diffuses from the 2¼ Cr-1 Mo steel toward the weld metal during welding. Carbon loss in the 2¼ Cr-1 Mo steel results in the dissociation of chromium-rich carbides in the grain boundaries, which then leads to grain boundary migration. The resulting 2¼ Cr-1 Mo steel microstructure near the weld interface has prior-austenite grain boundaries parallel to the fusion line. The distance of these grain boundaries from the fusion line is a measure of the extent of decarburization. (This description applies for a high-nickel filler metal. Because carbon is more soluble in type 309 stainless steel filler metal than the high-nickel filler metal, more carbon diffuses to this weld metal, leading to more grain boundary migration and a somewhat different grain structure. The fracture mechanism still applies.) After the carbides in the grain boundaries dissociate, regions high in chromium are left behind and grow at the expense of the chromium in the surrounding matrix.

When cooled from welding temperature and while in service, the high-chromium regions in the grain boundaries carburize. Formation of the chromium-rich regions that eventually become carbides occurs at the expense of the chromium in solution in the matrix immediately adjacent to the grain boundaries. The lower chromium concentration in the vicinity of the prior-austenite grain boundaries leads to lower oxidation resistance of the 2¼ Cr-1 Mo steel. Inevitably, an oxide notch forms at the external surface (inner or outer) in this chromium-depleted region at the grain boundary. (The chromium concentration in solution in the 2¼ Cr-1 Mo steel matrix and grain boundaries determines the oxidation resistance.)

A fatigue crack was postulated to nucleate below the oxide notch (Ref. 3). Nucleation is caused by external-loading stresses superimposed on the internal tube pressure and the cyclic thermal stresses during heating and cooling of the fossil-fired plant. The thermal stresses are due to the differences in coefficients of thermal expansion of the materials making up the joint. The difference in external loads (i.e., bending stresses and welding stresses) on different tubes explains why some tubes fail and other similar ones do not.

Once a crack is nucleated, it will propagate in the chromium-depleted region. Crack propagation occurs under the influence of the external load, the internal tube pressure, and the cyclic thermal stresses; it can also be aided by the stress generated by the large volume of oxide formed within a crack. More important, this region has lower strength because of carbon loss during welding and service, so crack propagation through this region is easier.

Of crucial importance to the proposed mechanism is the enrichment of chromium in the prior-austenite grain boundaries of the 2¼ Cr-1 Mo steel heat-affected

zone. Microprobe analysis showed that the carbides within the grain boundaries are enriched in chromium relative to the matrix immediately adjacent to the grain boundaries. Work by other investigators has also demonstrated chromium enrichment at grain boundaries during welding.

The mechanism envisioned applies to fusion welds made with both a high-nickel and austenitic stainless steel filler metal, even though there is a slightly different fracture morphology. Indeed, the proposed mechanism applies extremely well for induction-pressure welds, where a very different fracture morphology was observed at the outer and inner diameters. The different morphology was explained in terms of the microstructural changes that occur during welding.

The mechanism envisioned applies to fusion welds made with both a high-nickel and austenitic stainless steel filler metal, even though there is a slightly different fracture morphology. Indeed, the proposed mechanism applies extremely well for induction-pressure welds, where a very different fracture morphology was observed at the outer and inner diameters. The different morphology was explained in terms of the microstructural changes that occur during welding.

Based on the proposed failure mechanism, several possible solutions were proposed (Ref. 3). Elimination of external loading stresses is the most obvious. (Although this suggestion seemed obvious at the time, as shown below, external stresses have now been shown to play a major—and probably a pivotal—role in failure.) Other suggested solutions include oxidation-resistant coatings on the external surfaces of the welds and transition pieces (spool pieces) between the tubes to lower the thermal stresses. In addition to proposing a spool piece that would lower thermal stresses, the proposed failure mechanism leads to a possible alternative transition-piece solution: a carbon-stabilized chromium-molybdenum steel transition piece with higher chromium concentration than 2¼% Cr. Besides keeping sufficient chromium available to maintain oxidation resistance and thus avoid oxide notch formation, the higher chromium concentration and carbon stabilization of such a spool piece may also lower the amount of carbon transferred during welding and service.

Utility study

There has been one detailed utility study designed to relate the observation of joint failures to conditions existing in an operating fossil-fired boiler. Dooley, et al (Ref. 4), at Ontario Hydro conducted an investigation at what they called "station A." This plant consisted of two 300-MW units that contained about 31,000 type 309 stainless steel fusion welds. Five welds had failed during its first 50,000 hours of operation, in which approximately 350 starts had been made.

Four of the five failures occurred in the furnace (heat-absorbing joints), the other in the vestibule. A dye-penetrant inspection of other dissimilar-metal welds in the vicinity of the failed welds indicated that more than 50% of the welds contained incipient cracks. As a result of that observation, a decision was made to replace all of the welds in both units.

In an investigation to determine the cause of the failures, it was found they occurred in conjunction with the failure of the sliding support-spacer pieces near the welds. Failure of these supports was found to lead to large bending stresses on the dissimilar-metal weld joints. Metallographic examination of failed joints gave clear indication of this bending.

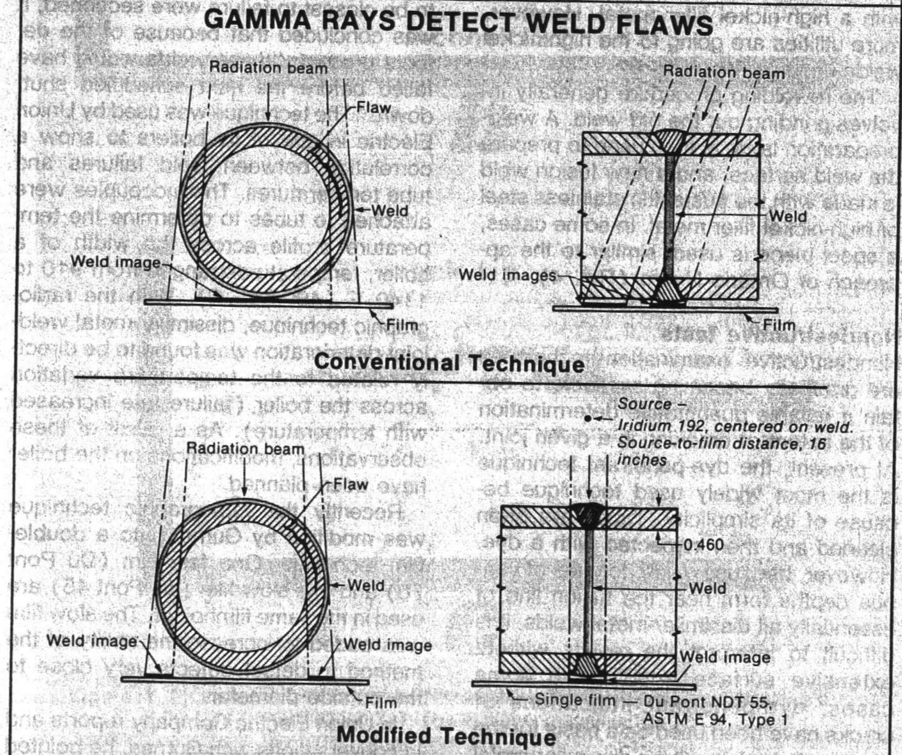
As proof of the importance of the joint-support structure, the Ontario Hydro investigators examined transition welds from a "station B," which consisted of two 500-MW units in which no failures had occurred. None of the welds that were examined metallographically gave any indication of cracking, and there was "only minimal oxide notching." It was concluded that the major difference in design in the stations "is the use of ladder-type supports" for station B. These supports "permit free lateral expansion, while providing reliable support."

Because the differential thermal stresses in a joint are caused by temperature changes, the temperature cycles in stations A and B were monitored by attaching thermocouples to tubes. Measurements were made during two-shift operation, where the station was on load for 16 hours with an 8-hour overnight shutdown. It was found that furnace tubes were 30-50 C (55-90 F) hotter than those in the vestibule and ramp rates during start-up reached 300 C/hr (540 F/hr). Observations were similar in both stations. This was taken as further evidence of the importance of bending stresses caused by inadequate tube support.

The Ontario Hydro investigators have also originated an accelerated test for transition-joint welds. They used this test on fusion welds made with type 309 stainless steel filler metal to demonstrate the importance of bending in accelerating failure.

The replacement welds used by Ontario Hydro are fusion welds made with Inconel 182 SMA filler with a GTA root pass made with Inconel 82. Although service failures of Inconel 132 have been reported, no failures have been recorded with Inconel 182 (Ref. 4). However, the

Figure 3. Schematic diagram of the radiographic technique developed at Union Electric Co. for detecting flaws in dissimilar-metal welds in boiler tubes. The modified technique is compared to the conventional technique. Diagram is from *Welding Engineering and Design*, September 1981.



Front and side views of weld cross sections show conventional and modified gamma radiographic techniques for locating weld flaws, lack of fusion, or HAZ cracking, in small-diameter (2-1/8 inch) tubing. The modified technique succeeds because rays travel through relatively large volumes of a defect.

authors note the difficulty of making Inconel-type welds, and the use of such welds could lead to failures caused by welding defects such as lack of fusion or root penetration. Because of the considerable difference in coefficient of thermal expansion between the stainless steel and the Inconel-type filler metal, stresses at these interfaces could lead to premature failure of welds containing defects. Two such failures on the stainless steel side of the joint had occurred at Ontario Hydro, but repairs had been made without metallographic examination to determine the exact cause of failure.

In an attempt to minimize the problems inherent in making the Inconel-type welds in the field, Ontario Hydro's practice is to repair dissimilar-metal weld failures by the use of a short spool piece that is made in the shop. This spool piece, which contains the dissimilar-metal weld, is then installed in the boiler by making the much simpler similar-metal welds (ferritic steel to ferritic steel and stainless steel to stainless steel). Prior to installation in the boiler, the spool-piece dissimilar-metal weld is radiographed.

In conversations with utility engineers that have dealt with the dissimilar-metal weld problem, it is found that various approaches have been taken toward repair. Although a high-nickel filler metal is known to offer a longer joint lifetime, some utilities still replace failed type 309 stainless steel welds with type 309 stainless steel. This is generally done because of the known difficulty of making welds with a high-nickel filler metal. However, more utilities are going to the high-nickel welds—usually Inconel 182.

The rewelding procedure generally involves grinding out the old weld. A weld-preparation lathe is then used to prepare the weld surface, and a new fusion weld is made with the austenitic stainless steel or high-nickel filler metal. In some cases, a spool piece is used, similar to the approach of Ontario Hydro (Ref. 4).

Nondestructive tests

Nondestructive examination techniques are gradually becoming available to obtain a reliable quantitative determination of the extent of cracking in a given joint. At present, the dye-penetrant technique is the most widely used technique because of its simplicity. Tubes are often cleaned and then inspected with a dye. However, because oxide notches of various depths form near the fusion line of essentially all dissimilar-metal welds, it is difficult to interpret the results without extensive surface grinding. In some cases, dye-penetrant indications of cracks have been used as a basis for the decision to replace all the dissimilar-metal welds within a boiler. When such indications are obtained in conjunction with several joint failures, replacement of all joints is taken as the prudent course.

J. H. Smith at the Oak Ridge National Laboratory has developed an ultrasonic detection technique for use in inspecting the dissimilar-metal weld joints in the large-diameter pipes of the Clinch River Breeder Reactor. The use of these techniques on the much smaller diameter boiler tubes is fraught with difficulties. Cracks may be detected in some cases, but without the extensive development of standards, it is impossible to guarantee that all cracks have been detected. Smith believes that eddy-current detectors may eventually offer the best possibility for inspecting such welds. Work is presently in progress to develop such detectors.

The most promising nondestructive examination technique to emerge for this problem is a modification of the conventional radiographic technique for tubes. This technique was introduced by R. F. Gurnea of the Union Electric Company of St. Louis (Ref. 5); it uses an iridium-192 source, but modifies the angle of incidence of the gamma-ray beam on the tube and weld (see Fig. 3). Because the rays travel through a relatively large volume of defect, the defect is more easily detected. According to Gurnea, "To be detectable by radiography, the defect must run somewhat continuously around a section of the weld." This condition has been found to be the case for dissimilar-metal welds in the failure process.

To prove the technique, Gurnea and his colleagues radiographed 123 welds and found linear indications in 21. When the four welds that the radiographs revealed to be closest to failure were sectioned, it was concluded that because of the defects present, "these welds would have failed before the next scheduled shutdown." The technique was used by Union Electric in one of its boilers to show a correlation between weld failures and tube temperatures. Thermocouples were attached to tubes to determine the temperature profile across the width of a boiler; temperatures ranged from 910 to 1140 F (490-615 C). With the radiographic technique, dissimilar-metal weld-joint deterioration was found to be directly related to the temperature variation across the boiler (failure rate increased with temperature). As a result of these observations, modifications on the boiler have been planned.

Recently the radiographic technique was modified by Gurnea into a double-film technique. One fast film (Du Pont 70) and one slow film (Du Pont 45) are used in the same filmholder. The slow film was added to increase the ability of the method to detect defects very close to the outside diameter.

In Union Electric Company reports and in conversations with Gurnea, he pointed out that there are some problems with the technique, just as with any new process. Even with the two-film technique, outside-diameter cracks were not detected on two welds which were subsequently sectioned. However, if they had remained in the boiler, they would probably have been detected on subsequent radiographic inspections, prior to any in-service failure. Gurnea pointed out that to date the new technique has served their purposes well; since it has been in use, no in-service failures have occurred in areas of Union Electric boilers that have been inspected utilizing the technique.

One limitation of the technique is that no other workers can be in the area of the boiler where radiographs are being made. For that reason Union Electric is also interested in ultrasonic detection techniques. Although at present this technique is highly operator-dependent and limited by the rough tubing finish, efforts are under way to refine the process.

J. Schaefer of Detroit Edison has used the Union Electric technique with success. In the original trial, Detroit Edison engineers inspected 276 welds of a boiler unit. Thirty-eight percent gave significant indications of cracking. Eleven appeared to be very near failure. As it was not possible to replace all of these joints during that shutdown, the welds were prioritized according to the radiographic information. Those judged closest to failure were replaced. When future inspections are made, Schaefer proposes to compare old and new radiographs to determine crack-propagation rates, information that would prove useful in the future.

The improved nondestructive testing techniques offer utility engineers a chance to monitor dissimilar-metal weld deterioration, and in cases where it is not possible to replace all the welds in an operating boiler, the affected welds can be individually replaced as the need arises. This development coupled with a better understanding of the failure mechanism and an understanding of the stresses responsible for the failures should lead to dissimilar-metal welds with lifetimes similar to those of the steam tubes. **END**

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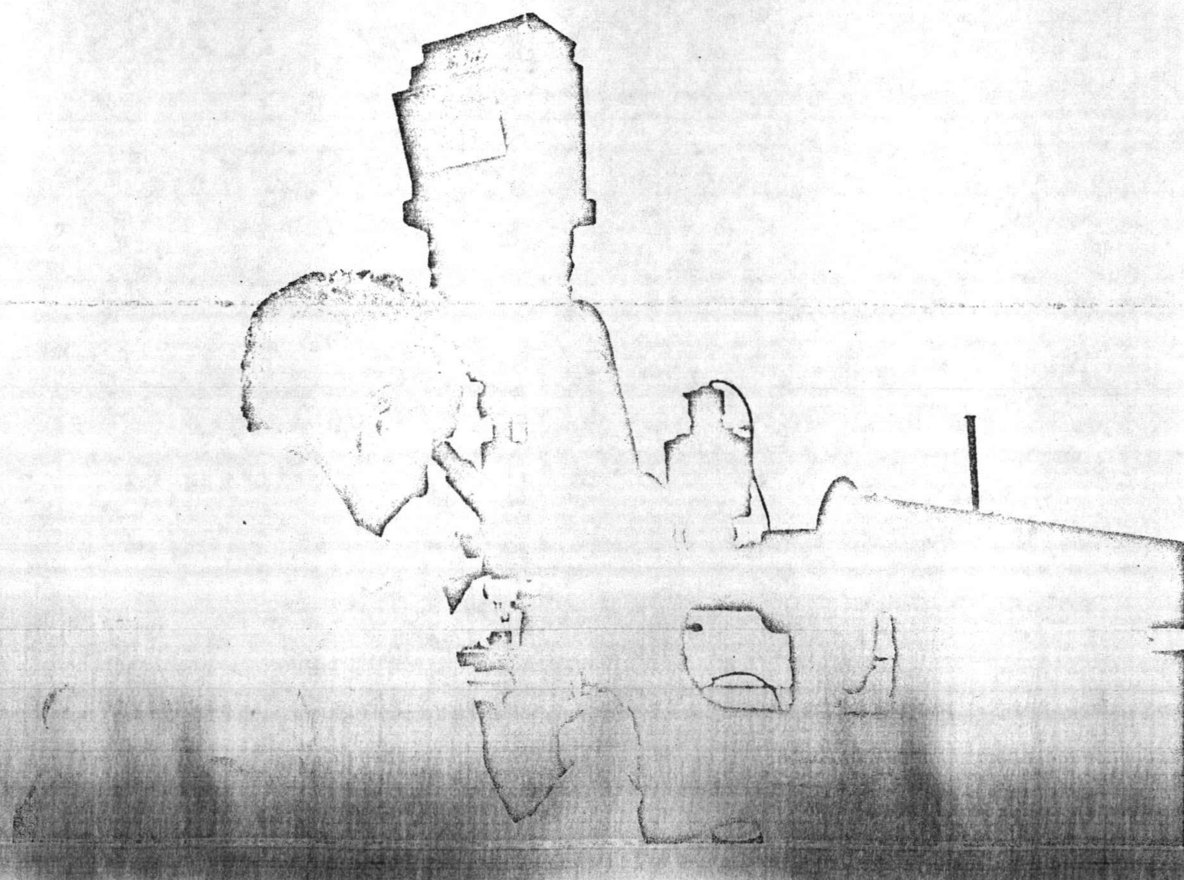
BULLETIN 61

NALCO

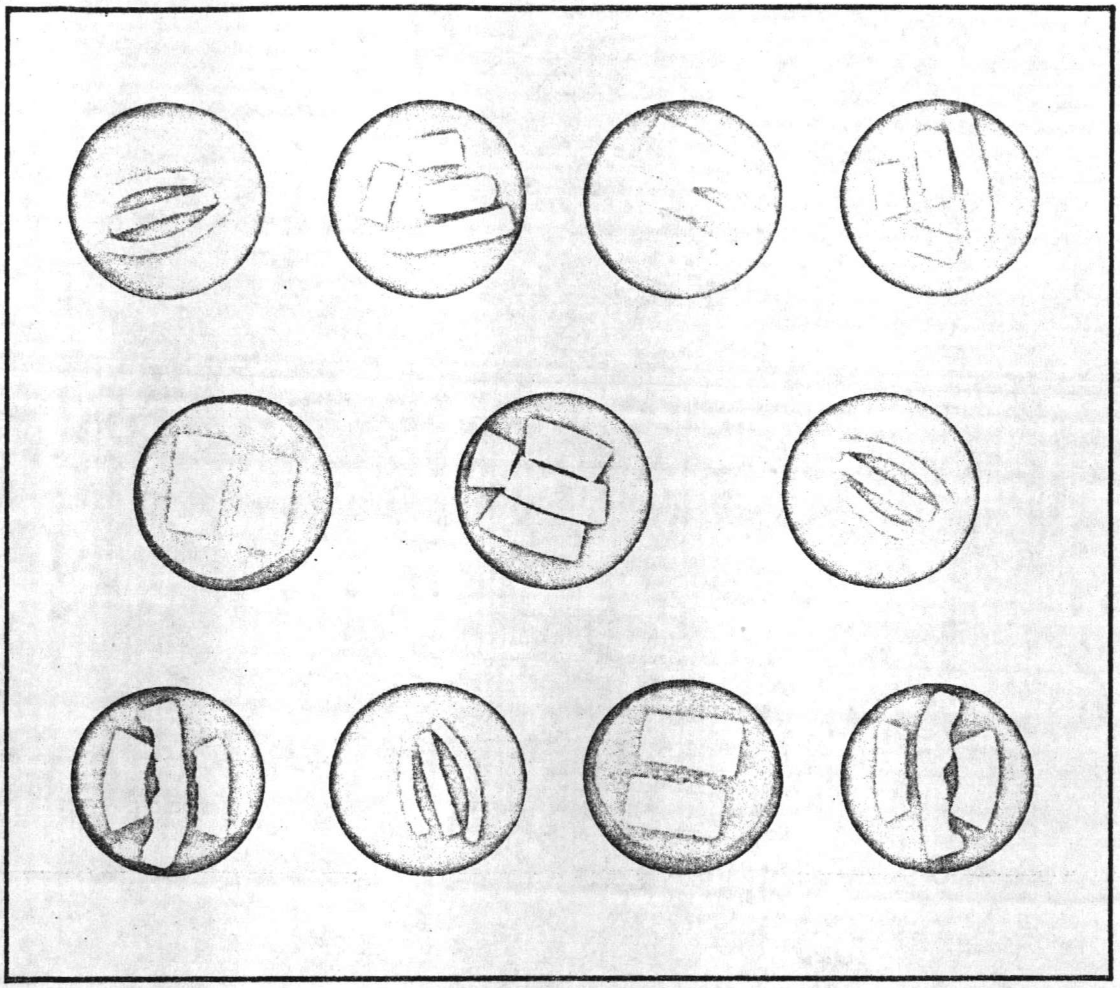
INTRODUCTION TO BOILER METAL FAILURE ANALYSIS

WITH

METALLOGRAPHIC GLOSSARY



METALLOGRAPHIC EXAMINATION

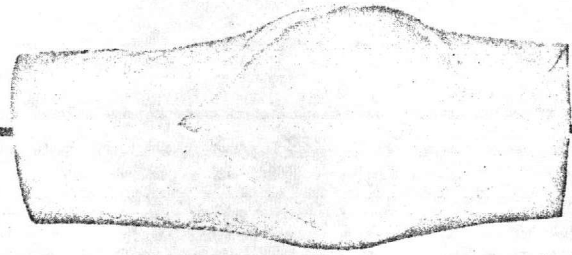


Most boiler tube failures are the result of two adverse conditions, excessive heat or chemical attack, or a combination of the two. Excessive heat produces permanent, significant changes in the micro metallographic appearance of the steel which can be observed and photographed. These changes in structure begin to occur slowly at a temperature around 900° F and much more rapidly above 1350° F.

In order to see the significant structure, small steel specimens are cut, molded in plastic for convenient handling, and the surface of the specimen ground, polished and etched. These specimens, pictured above, are examined with a special microscope, shown on cover.

Complete metal failure analyses are among the services offered by Nalco Chemical Company.

Metal Failures . . .



. . . often due

RIGHT: Photograph of a failed boiler tube. For metallographic study small sections are cut from areas of both normal and abnormal structure.

Figure 1 is a photomicrograph at 500 magnifications of the low carbon steel used in fabrication of boiler tubes. This photomicrograph shows normal steel structure which is composed of ferrite and pearlite. The light colored ferrite is iron containing a low percentage of carbon in solid solution. Pearlite, the dark grains, is composed of ferrite and cementite in a banded or layered structure. Cementite is an iron-carbon compound (Fe_3C).

The photograph above pictures a failed boiler tube. To determine the metallographic causes of failure, small sections are cut from selected locations that show both the normal and the modified structure of the steel. These sections are mounted, polished and etched, then examined by the metallographer.

Five conditions of steel structure related to excessive heating (see diagram, page 5), and three related to other destructive conditions (see table, page 6), are identifiable.

Figure 2 shows intergranular oxidation. Note the dotted dark lines of iron oxide around grains, and also larger dark areas of iron oxide. Steel at high temperatures (usually above 1350°) and in contact with oxygen bearing gas frequently oxidizes most rapidly at the grain boundaries. This weakens the bond between the crystals and failure may occur.

Figure 3 pictures decarburization. Note absence of the normally present pearlite areas because of loss of carbon by conversion to gaseous compounds. This change takes place when steel is heated above 1350° F with oxygen present, or may occur with hydrogen penetration at lower temperatures.

Figure 4 shows a section that has undergone grain growth. Note enlarged grains compared to Figure 1. Decarburization has also occurred. At temperatures above 1550° F grain size tends to increase, resulting in loss of tensile strength.

Figure 5 shows quenched structure and needle crystals. When steel is heated to temperatures above 1350° F and quickly cooled, this structure frequently results.

Figure 6 pictures spheroidization. Note that the dark pearlite areas evident in Figure 1 are absent, due to rearrangement of cementite into rounded grains. It results from prolonged heating of low carbon steel in the 900 — 1350° F range, a combined time/temperature effect. It occurs very slowly at 900° F, but may require only a few hours at 1350° F.

NORMAL STEEL STRUCTURE

Figure 1

to overheating

INTERGRANULAR OXIDATION

Figure 2

DECARBURIZATION

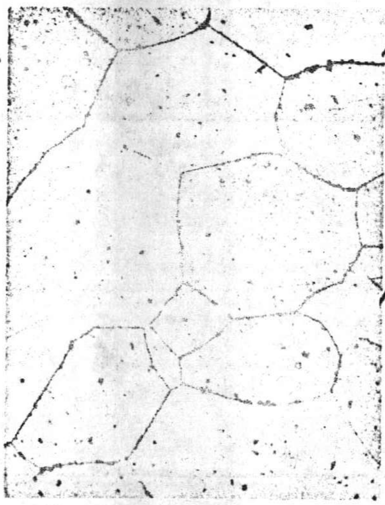
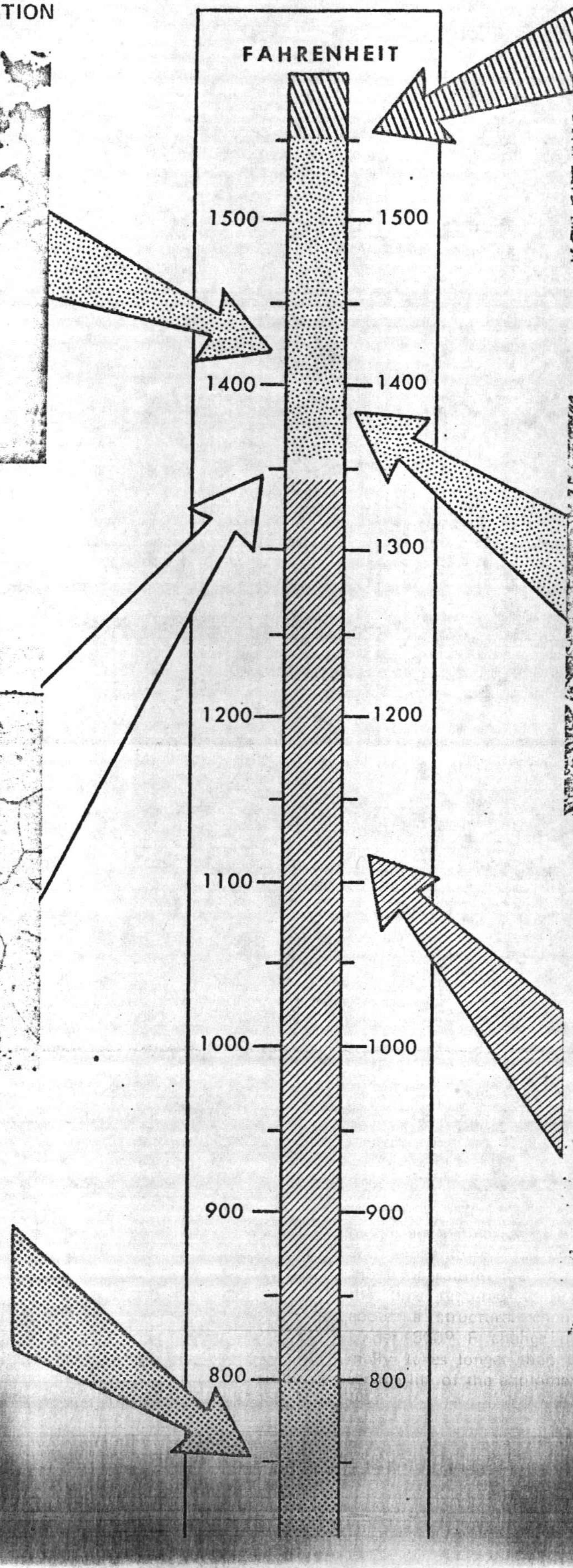


Figure 3



GRAIN GROWTH

Figure 4

QUENCHED STRUCTURE

Figure 5

SPHEROIDIZATION

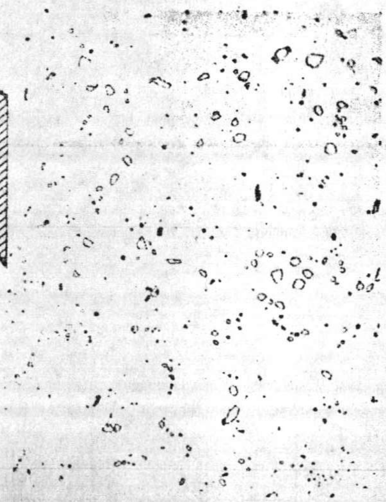


Figure 6

Changes in microstructure of metals are a function of time and temperature. The higher the temperature, the shorter the time required to bring about a structural change. Under 800° F change normally takes longer than the service life of the equipment.

Figure 7 shows a corrosion fatigue crack. This condition occurs under repeated cyclic stress, where the normal protective oxide on the steel surface is repeatedly broken and reformed at the expense of the metal. The resultant progressive cracking, primarily across the grains, leads to ultimate failure of the steel. Heating is not a primary factor in corrosion fatigue cracking, but will accelerate failure.

Figure 8 shows caustic cracking. It occurs in the grain boundaries and originates at a surface. The cracks are always continuous. The following four conditions must be present to cause caustic cracking of steel.

1. The metal must be under a close to yield-point tensile stress.
2. There must be some local mechanism, such as a small leak that allows water to flash away and leave behind high concentrations of boiler water solids in contact with the stressed metal.
3. The concentrated boiler water solids must contain caustic.
4. The concentrated boiler water solids must contain silica.

SOME TYPES OF BOILER CORROSION

TYPE OF ATTACK	CONDITIONS CAUSING TROUBLE
1. Corrosion Fatigue	A. Cyclic stress and corrosive environment.
2. Decarburization	A. High temp. plus oxygen. B. Hydrogen penetration.
3. Oxygen Pitting	A. Intermittent or continuous exposure to oxygen containing water.
4. Concentrated Boiler Water Solids.	A. Local concentrating mechanism for boiler water. B. Elevated temperature.

CORROSION FATIGUE

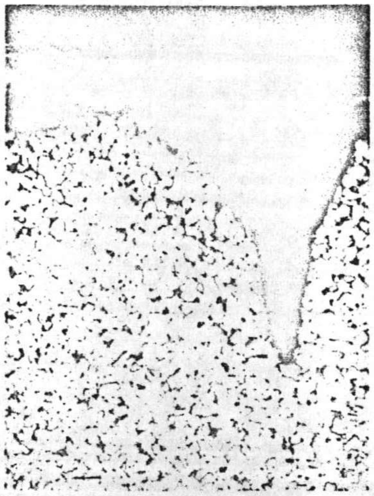


Figure 7

CAUSTIC CRACKING

Figure 8

METALLOGRAPHIC examinations can produce accurate data on immediate cause of metal failure. However, because the metal has usually been subjected to various temperatures before failure occurred, most metal specimens examined do not show single, clear cut, textbook cases of the individual types of failure. Thus a skilled and experienced metallographer is needed to prepare sections and interpret photomicrographs. In addition, it is essential that a complete environmental service history be available to aid in the correct diagnosis of the trouble and provide a basis for accurate recommendations for future trouble-free operation.

ACICULAR — A spine or needle shaped crystal whose length is three or more times it width.

ALLOY — A substance that has metallic properties and is composed of two or more chemical elements of which at least one is a metal.

ALPHA IRON — The form of iron which is stable below A_3 point (1670° F) and has body centered cubic structure.

ANODE — In corrosion, the electrode where oxidation is occurring.

ANNEALING — A process of heating and cooling; usually involves heating to slightly above A_3 point followed by slow cooling. Used to induce softness, relieve stresses, to form pearlitic structure, to produce grain refinement and to remove gases.

AUSTENITE — A solid solution in which gamma iron is solvent (structure normally present in steel above A_3 point): characterized by a face centered cubic structure. Austenite is non-magnetic.

BAINITE — A decomposition product of austenite consisting of an aggregate of ferrite and carbide. In general, it forms at temperatures lower than those where fine pearlite forms and higher than that where martensite begins to form on cooling. Its appearance is: (1) feathery if formed in the upper part of the temperature range, (2) acicular, resembling tempered martensite, if formed in the lower part.

BANDED STRUCTURE — A segregated structure of nearly parallel bands of metal crystals aligned in the direction of working.

BRITTLE FRACTURE — Fracture with little or no plastic deformation.

CARBIDE — A compound of carbon with one or more metallic elements.

CARBON STEEL — Steel that owes its properties chiefly to the presence of carbon, without substantial amounts of other alloying elements; also termed, ordinary steel, straight carbon steel, or plain carbon steel.

CARBURIZATION — The introduction of carbon into a solid ferrous alloy by holding above Ac_1 (see transformation temperature), in contact with a suitable carbonaceous material.

CAUSTIC CRACKING — A form of continuous intergranular cracking originating at the surface of the metal, caused by the attack of caustic on the "cement" between highly stressed metal grains. Because resultant metal fractures have a brittle appearance, the form of attack is commonly referred to as caustic embrittlement.

CAVITATION DAMAGE — Wearing away of metal through the formation and collapse of cavities in a liquid.

CEMENTITE — A compound of iron and carbon known as iron carbide (Fe_3C); characterized by great hardness. Makes up alternate lamellae in pearlite.

COALESCENCE — The union of particles of a dispersed phase into larger units, usually effected below the fusion point. (i.e. carbide migration).

COLD WORK — Any of various metalworking operations carried out below critical temperature range. In general, it consists of plastic deformation at such temperatures and rates that substantial increases occur in strength and hardness of metal. Visible structural changes include distortion of grains and in some cases, mechanical twinning or banding.

COOLING STRESSES — Stresses developed by uneven contraction or external constraint of metal during cooling; also those stresses resulting from localized plastic deformation during cooling.

CORING — A variable composition between the center and surface of a unit of structure.

CORROSION FATIGUE — The repeated cyclic stressing of a metal in a corrosive medium, resulting in faster deterioration than would be encountered as the result of either cyclic stressing or of corrosion alone. Under boiler conditions, it often refers to

cracking resulting from progressive breakdown of protective oxide films due to cyclic stressing.

CRATER-TYPE CORROSION — (See Ductile Gouging)

CREEP — The plastic flow or deformation of metals held for long periods of time at stresses lower than the normal yield strength and at temperatures rendering the metal susceptible to such yielding. Long time creep at elevated temperatures frequently yields intergranular, discontinuous, cracks.

CREVICE CORROSION — A type of corrosion caused by the concentration of dissolved salts, metal ions, oxygen or other gases, in crevices or pockets remote from the principal fluid stream, with a resultant building up of differential cells that ultimately cause deep pitting.

CRITICAL POINT — (See Transformation Temperature)

CRITICAL RANGE — Temperature range between A_1 and A_3. (See Transformation Temperature)

DARK ETCHING CONSTITUENTS — Constituents of a microstructure which appear dark after etching. They are generally mixtures - - not a single, well defined material.

DECARBURIZATION — The loss of carbon from a ferrous metal as a result of heating in a medium that reacts with carbon.

DENDRITIC — A structure that has a tree-like branching pattern, being most evident in cast metals cooled slowly through the solidification range.

DEZINCIFICATION — Corrosion of a brass involving loss of zinc and formation of a residue or deposit of copper in the form of plugs or layers.

DUCTILE FRACTURE — A fracture in which distortion of grains is evident.

DUCTILE GOUGING — A localized pitting or crater type attack normally characterized by wastage of tube metal beneath a porous deposit or at some other point of chemical concentration. It progresses to failure when the tube wall thins to a point permitting local stress rupture. The microstructure of the damaged metal does not change, and the tubing retains its ductility.

ELASTIC LIMIT — The maximum stress that a material will withstand without permanent deformation.

EMBRITTLEMENT — Reduction in normal ductility of a metal due to a physical or chemical change. (Also see Caustic Cracking, Hydrogen Embrittlement)

ETCHING — In metallography, the process of revealing structural details by the preferential attack of reagents on a metal surface. For ferrous metals 2% nitric acid in ethyl alcohol (nital) and 4% picric acid in ethyl alcohol (picral) are most commonly used.

EUTECTOID STEEL — This composition in pure iron-carbon alloys is 0.8% C but variations from this composition are found in commercial steels and particularly in alloy steels in which the carbon content of the eutectoid is usually lower. Structure will be all pearlite.

EXFOLIATION — A type of corrosion that progresses approximately parallel to the surface of the metal, causing layers of the metal to be elevated by the formation of corrosion products. This type of corrosion is most commonly associated with cupro-nickel alloys and aluminum.

FATIGUE — The tendency for a metal to break under conditions of repeated cyclic stressing considerably below the ultimate tensile strength.

FATIGUE CRACK — A fracture that is progressive starting from a nucleus where there is an abnormal concentration of cyclic stress (such as a notch) and propagating through the metal.

FERRITE — A solid solution in which alpha iron is the solvent. Comprises the light areas in normal, etched, low-carbon steel.

FILLET — A concave junction of 2 surfaces.

FOLDS — Defects caused by continued fabrication of overlapping surfaces, sometimes called a "lap".

FREE FERRITE — Ferrite formed from austenite during cooling without simultaneous formation of carbide.

GAMMA IRON — The form of iron stable above A_3 point and characterized by face centered cubic structure. Will dissolve up to 1.7% carbon to form austenite. Gamma iron is non-magnetic.

GRAIN GROWTH — An increase in grain size in metals. In boiler tubes it is an indication of overheating to temperatures above A_3 point for sufficient length of time.

GRAIN SIZE — Expressed in terms of number of grains per unit area. Usually grain size is expressed as numbers and determined at 100 diameters magnification. On ASTM scale numbers run from 1 to 8 with No. 1 being largest grain size and No. 8 the smallest.

GRAPHITIC CORROSION — Corrosion of gray cast iron in which the metallic iron constituent is converted into corrosion products, leaving the graphite intact.

GRAPHITIZING — A heating and cooling process by which the combined carbon in cast iron or steel is transformed wholly or partly to graphite or free carbon.

HARDNESS — Defined in terms of method of measurement. (1) Usually resistant to indentation, (2) Stiffness or temper of wrought products, (3) Machinability characteristics and (4) Brinell and Rockwell hardness scales are almost exclusively used. Brinell measures diameter of indentation under given load and Rockwell measures depth of indentation.

HYDROGEN EMBRITTLEMENT — A form of embrittlement caused by the diffusion of atomic hydrogen into the steel, reacting with carbon and other non-metallic impurities at the grain boundaries of the steel. The steel is thus decarburized and the resultant formation of methane and other gases builds up high pressures that cause discontinuous intergranular cracks in the metal.

INCLUSIONS — Particles of impurities (usually oxides, sulfides, silicates and such) that are held mechanically or are formed during solidification or by subsequent reaction within the solid metal.

INTERCRYSTALLINE — INTERGRANULAR — Between the grains or crystals of a metal.

INTERGRANULAR CRACKING — Cracks or fractures which follow along the grain boundaries in the microstructure of metals and alloys. (Also intercrystalline)

INTERGRANULAR CORROSION — A type of electrochemical corrosion that progresses preferentially along the grain boundaries of an alloy, usually because the grain boundary regions contain material anodic to the central regions of the grains.

KILLED STEEL — Steel deoxidized with a strong reducing agent such as silicon or aluminum in order to reduce oxygen content to a minimum so that no reaction occurs between carbon and oxygen during solidification. This prevents decarburized rims.

LAMINATIONS — Metal defects with separation or weakness generally aligned parallel to the worked surface of the metal. May be the result of defects in the original ingot.

MACROGRAPH — A photographic reproduction that has not been magnified more than 10 times.

MALLEABILITY — The property that determines the ease of deforming a metal when the metal is subjected to rolling or hammering. The more malleable metals can be hammered or rolled into a thin sheet more easily than others.

MARTENSITE — An unstable constituent in quenched steel formed without diffusion and only during cooling below a certain temperature. The structure is characterized by its acicular appearance on the surface of a polished and etched specimen. Martensite is the hardest of the transformation products of austenite. Quenched structures found in ruptured boiler tubes are frequently martensitic.

MATRIX — The principal phase or base metal in which another constituent is present.

METALLOGRAPHY — The science concerning the constitution and structure of metals and alloys as revealed by the microscope.

MICROSTRUCTURE — The structure of polished and etched metal and alloy specimens as revealed by the microscope.

NECKING — Localized reduction in area during tensile deformation.

NOTCH SENSITIVITY — The reduction caused in normal strength, impact or static, by the presence of a stress concentration usually expressed as the ratio of notched to unnotched strength.

OVERHEATING (BOILER METAL) — Changes in microstructure in boiler metal caused by excessive metal temperatures. The metal may or may not be permanently damaged.

PEARLITE — The lamellar aggregate of ferrite and carbide. This is the normal or original carbide structure of most steel specimens examined.

PHASE — A physically homogeneous portion of a material system.

PHASE DIAGRAM — A graphical representation of the equilibrium temperature and composition limits of phase fields and phase reactions in an alloy system. In a binary system temperature is usually the ordinate and composition the abscissa.

PHOTOMICROGRAPH — A photographic reproduction of any object magnified more than 10 diameters.

PLASTIC DEFORMATION — Permanent distortion of a material under the action of applied stresses.

POROSITY — Unsoundness in cast metals caused by voids.

QUENCH HARDENING — The process of hardening a ferrous alloy of suitable composition by heating within or above the critical range and cooling at a rate sufficient to increase the hardness substantially. The process usually involves the formation of martensite.

RECRYSTALLIZATION — The change from one crystal structure to another, as occurs on heating and cooling through a critical temperature.

REFORMED PEARLITE — Pearlite in an overheated region which formed because of slow cooling. It generally is of a different grain size than that in original metal.

RESIDUAL STRESS — Stress present in a body that is free of external forces or thermal gradients.

RIMMED OR RIMMING STEEL — An incompletely deoxidized steel normally containing less than 0.25% C and having the following characteristics: (a) during solidification an evolution of gas occurs sufficient to maintain a liquid ingot top until a side and bottom decarburized rim of substantial thickness has been formed, (b) after completed solidification the ingot contains two distinct zones — a decarburized rim somewhat purer than when poured and a core of desired carbon content and scattered blowholes.

SEAM — On the surface of metal, an unwelded fold or lap which appears as a crack, usually resulting from a defect in casting or working. Also may be a mechanical or welded joint, which may or may not have a different microstructure.

SEGREGATION — Concentration of metal constituents at specific regions.

SENSITIZATION — The increased susceptibility to intergranular corrosion in austenitic stainless steels. A stainless steel that is sensitized can be detected metallographically as prominent grain boundaries.

SELECTIVE LEACHING — The removal of one element from a solid alloy by corrosion processes. Common examples of this type of corrosion are dezincification, and graphitic corrosion.

SPHEROIDITE — An aggregate of iron or alloy carbides of essentially spherical shape dispersed throughout a matrix of ferrite.

SPHEROIDIZING — Any process of heating and cooling (usually prolonged mild overheating) that produces a rounded or globular form of carbide in steel.

STRESS CORROSION CRACKING — Failure of metals by combined action of corrosion and stress, residual or applied. Sometimes called season cracking when applied to copper alloys.

STRESS RELIEVING — A process of reducing residual stresses in a metal by heating it to a suitable temperature.

TEMPERED MARTENSITE — The dark etching, acicular structure that is developed by heating martensite to permit the precipitation of numerous tiny carbide particules.

TEMPERING — The reheating of quench-hardened steel to a temperature below the critical or transformation range and cooling as desired.

TENSILE STRENGTH — For practical purposes, the maximum load in psi which a metal will withstand before fracture.

TRANSCRYSTALLINE (TRANSGRANULAR) — Literally, across the crystal (or grain).

TRANSFORMATION PRODUCTS OR STRUCTURES — Microstructures that are the result of heating within the transformation range. They are frequently not resolvable as to a single structure, but exist as mixtures.

TRANSFORMATION TEMPERATURE — The temperature at which a change in phase occurs. The following symbols are among those used for iron and steel:

A_1 — The temperature at which austenite begins to form on heating.

Ac_3 — The temperature at which transformation of ferrite to austenite is completed during heating.

Ar_1 — The temperature at which transformation of austenite to ferrite plus pearlite is completed during cooling.

Ar_3 — The temperature at which austenite begins to discard ferrite on cooling.

NOTE: All changes occur at lower temperatures on cooling than during heating and depend upon rate of change of temperature. For our purposes, we will assume that equilibrium conditions exist and will call lower critical point A_1 and upper critical point A_3.

TUBERCULATION — The formation of localized corrosion products scattered over the surface in the form of knob-like mounds.

TWIN — Two portions of a crystal which appear as parallel lines, and are related to each other in orientation as mirror images.

YIELD POINT — In low and medium carbon steel, the stress at which a marked increase in deformation occurs without increase in load.

Ray Smith

January 20, 1966

MEMORANDUM:

Jack Elston
Detroit Office

Ford Motor Company
Dearborn Engineering Office

Dear Jack:

There is sufficient evidence contained in your memo to conclude that the 3 heads of the absorption unit have undergone graphitization, a corrosion phenomena not uncommon with cast iron. Graphitic softening is most often encountered when gray cast iron is in contact with aqueous solutions that are electrolytic in nature, although this is by no means the sole cause of the corrosion. It is characterized by the presence of a soft layer of graphite, representing the remains of the casting surface after iron had entered into solution. While it is pretty certain that the diagnosis is graphitization, I would be reluctant to specify the exact cause or causes of the condition.

You have mentioned that three heads show signs of softening and I assume that there is an unaffected head remaining. The fact that not all of the heads are graphitized seems to support the theory that any particular casting may be more or less susceptible to graphitic softening depending on the process of casting and cooling used. So you see, under any given set of conditions one head may graphitize while a seemingly similar head may not.

Other than the inherent susceptibility of cast iron to graphitization there are a number of contributing factors, one or several of which may be present in this absorption unit.

Factors Contributing to Graphitic Softening

1. Low pH.
2. Presence of hydrogen sulfide.
3. Sulfate reducing bacteria.
4. Stray electrical currents.
5. Waters high in magnesium or calcium sulfate.
6. High temperature.
7. Chlorine pockets caused by chlorination of the water.
8. High conductivity.
9. Brine.
10. Acid, as in periodic cleaning, may cause enough graphite to become isolated by way of iron removal, the resultant being a strongly cathodic graphite site causing corrosion of additional anodic iron.

I hope you can find an answer to the problem with this information.

Very truly yours,

R. H. Smith
Hall Laboratories Division

RHS:sw

cc Ed Elliott
cc Ray Smith
cc Detroit
cc File

Dictated 1/19/66

G1 S

A REPORT ON THE USE OF ALUMINUM CONDENSER TUBES AT ARMSTRONG STATION WEST PENN POWER COMPANY

by

M. D. Baker
Chief Chemist

Armstrong Station, West Penn Power Company, has two units, each approximately 165 mw. No. 1 unit is a General Electric unit and was placed in service April, 1958. The tubes in the condenser are Admiralty. No. 2 unit is a Westinghouse unit and was placed in service June, 1959. The tubes in the condenser are aluminum alloy 3003-H14 Alclad. Each condenser contains 9700 tubes 30' long 1" O.D. with a .058" wall. The tubes in the top row in No. 2 condenser are stainless steel alloy 304.

The boilers are identical, each boiler being a Foster Wheeler boiler, capable of delivering over, 1,300,000 lbs. of steam per hour at 1850 lbs. pressure; 1000° superheat; 1000° reheat. The boiler water conditions are as follows: the pH of the boiler water was set to be carried between 10.5 and 11.0; coordinated phosphate control is maintained; the maximum silica in the boiler water is set at 0.8 ppm and is usually carried at 0.4 or lower; hydrazine is used for oxygen scavenging; the amount of hydrazine feed is controlled by the pH of the condensate. When first starting up No. 2 unit the pH of the condensate limits was set at 8.5 to 9.0. Due to two tube failures in February, 1960--one entirely mechanical, the second having the appearance of ammonia corrosion on the steam side--it was decided to set the pH limits of the condensate between 8.0 and 8.5. An inspection made of the tubes at the time of the failure and during the annual inspection showed no visible attack on the steam side. The exterior of the tubes appeared to be coated with a thin wash of iron oxide. The coating is so thin that it is impossible to obtain a sample of it.

In May, 1960, it was decided to determine if any aluminum existed in the boiler water. Between May, 1960 and October, 1960, when the boiler and unit were opened for annual inspection, fifteen analyses were made for the aluminum in the boiler water. Eight of the fifteen analyses showed higher than 30 ppm of aluminum in the boiler water. The maximum was found on August 18, 1960 when 40 ppm was present. The boiler water analysis at this time was: pH 10.6, phosphate as PO_4 - 165 ppm, silica as SiO_2 - 0.04, sulfate as SO_4 - 1.0 ppm, and copper as Cu -.045 ppm, conductivity was 506 micromhos. The PO_4 content was in considerable excess of that required. According to the control curve, 48 ppm of phosphate was required to eliminate any hydroxide. The analysis for hydroxide using the barium chloride method indicated that 32 ppm of hydroxide was present. A sample was then analyzed using strontium chloride instead of barium chloride and the sample was heated to boiling. This method indicated 3 ppm of hydroxide present. The amount of hydroxide varies from 2 to 10 ppm when using the boiled strontium chloride

method. In practically all tests the presence of hydroxide has been indicated by this method when the aluminum content of the boiler water is 10 ppm or higher. The indicated presence of hydroxide raises this question. Is the aluminum present as a cation or as an anion?

During the inspection, deposits were removed from the boiler and from the turbine blades. The spectographic-microscopic examination of the deposits from the steam drum showed the major constituent to be metallic copper, a low major - iron spinel, a high minor - ferric iron oxide, with traces of nickel oxide, hydrated ferric oxide, calcium carbonate, magnesium compounds and aluminum compounds. The chemical analyses showed copper as Cu 69%, iron as Fe_3O_4 22% and nickel as NiO 7%.

A small amount of deposit, approximately 30 grams, was turbined from a division wall tube. The analyses of this deposit showed the major constituent to be cuprous oxide, low major - iron spinel, high minor - ferric oxide, low minor - calcium phosphate and metallic copper with traces of nickel, hydrated ferric oxide, silica as quartz and aluminum compounds. Chemical analyses showed copper as Cu 49%, iron as Fe_3O_4 35% and nickel as NiO 3%.

A deposit removed from the turbine blades 16th stage intermediate pressure showed a major constituent of sodium aluminum silicate, a low minor ferric iron oxide and trace amounts of phosphate and water soluble material. The deposit from the blade in the 4th row low pressure spindle showed the major constituent to be amorphous silica, a fair amount of sodium compounds, a low minor of magnetic iron oxide, slight amounts of aluminum compounds, potassium compounds and trace amounts of ferric iron oxide and hydrated ferric oxide.

The amount of deposit in the drum totaled approximately two quarts. The amount turbined from the division wall tube was approximately 30 grams. The deposit on the turbine blades was very light and difficulty was experienced in obtaining sufficient for analysis.

The boiler was replaced in service in November, 1960. Weekly analyses of the boiler water were made to determine the concentration of aluminum. The first two weeks the aluminum content varied between .4 and .5 ppm. The pH of the boiler water varied between 9.0 and 9.5. After two weeks of operation the aluminum content had increased to 4.9 ppm. The pH of the water was 10.8. In three weeks the aluminum concentration had increased to 9.7. The pH of the boiler water was 10.5. Until the end of January, 1961, the aluminum content of the boiler water remained at 10 ppm or lower with one exception of 11.25. The pH range was between 10.4 and 10.7. At this time the boiler was out of service for a few days. When starting up the boiler, the aluminum content was 1.2 ppm. The pH was 10.6. By

March 7, the aluminum had increased to 14.1 ppm. The pH was 10.5. On March 1, 1961 in an effort to lower the concentration of the boiler water and obtain the benefit of improved steam quality with lower boiler water concentration, it was decided to carry the pH of the boiler water between 10.0 and 10.5. Several months after the inspection of the equipment the turbine was water washed to restore the loss in efficiency. A few samples of the wash water were obtained. The samples collected did not represent the entire washing. The conclusion that could be arrived at from the analyses of the few samples was that the material removed from the turbine blades was high in aluminum. The water washing restored the efficiency of the turbine.

A copy of the boiler water analyses made from February 7 to June 5, 1961 are as follows:

Date	pH	Conductivity	PO_4	OH	SiO_2	Cu	Al
2/7/61	10.7	320	78	0	.20	.090	9.75
2/13/61	10.4	250	66	2	.08	.060	15.00
2/27/61	10.8	370	74	0	.17	.050	8.75
3/7/61	10.5	275	74	2	.30	.050	14.13
3/13/61	9.9	215	62	2	.20	.200	21.55
3/20/61	10.1	240	62	2	.28	.016	28.50
3/27/61	10.4	221	44	2	.08	.056	27.00
4/4/61	10.1	212	30	5	.06	.016	23.5
4/10/61	10.1	274	64	2	.04	.116	25.0
4/17/61	10.0	210	44	2	.02	.022	25.0
4/24/61	10.3	255	54	2	.10	.012	21.5
5/2/61	10.2	196	36	4	.08	.008	19.00
5/10/61	10.0	102	20	2	.07	.028	9.50
5/15/61	10.2	137	34	2	.05	.012	8.50
5/23/61	9.8	82	22	2	.08	.040	7.55
5/29/61	9.8	75	16	2	.08	.005	9.50
6/5/61	10.1	178	36	2	.08	.016	9.00

For some unexplained reason, at times the aluminum concentration in the boiler water increased when the pH was lowered. A survey was made on all the aluminum analyses to determine the cause for this increase. With the one exception when 40 ppm was found at a pH of 10.6, all other analyses when the concentration of aluminum was greater than 25 ppm the pH of the boiler water was between 9.9 and 10.5. This is illustrated in the change in the aluminum content in the analyses for the dates 2/27/61, 3/7 and 3/13/61. There were several occasions when a concentration of aluminum was high at a pH of 10.5 or lower. When the pH of the boiler water increased to 10.8 there was an appreciable drop in the aluminum concentration as illustrated during the period 2/7, 2/13 and 2/27/61. This information is offered as something that has occurred and is not cited with any thought of forming a definite conclusion. The favorite question "why" is applied.

Several steam quality tests have been made using the sodium tracer technique method. The indication of the tests that have been made is that the amount of sodium found in the steam from No. 1 boiler varies between 1 and 4 ppb. With similar concentrations of boiler water and with aluminum present in the boiler water the amount of sodium found in the steam from No. 2 boiler varies between 3 and 6 ppb, with occasional shots of 12 ppb at 2 of the 6 sample points on the saturated steam crossover tubes. Does this data indicate that the presence of aluminum in the boiler water means higher concentration of solids in the steam?

The boiler was removed from service for inspection on June 9, 1961. It was replaced in service on June 17, 1961. On June 23, a rear wall tube failed due to hydrogen embrittlement damage. Following this a series of failures and tube section replacements occurred. All damage was due to hydrogen embrittlement. The boiler was acid cleaned and headers inspected and deposits removed after the acid cleaning. The acid cleaning removed primarily iron and copper and some nickel. The deposits that remained in the header were primarily iron, copper and nickel. On August 12, 1961, the boiler was back on the line for continuous service. In no way could aluminum be connected with the embrittlement trouble.

This review is given with the intent of arousing interest and hoping the comparison of data from different companies may lead to the preparation of a worthwhile symposium showing the effects of aluminum in boiler water. To date, several literature surveys have been made with the result being negative as far as any information being obtained regarding the effect of aluminum in boiler water.

December 19, 1974

MEMORANDUM

TO: Gayle Starr
Charlotte, North Carolina

FROM: R. E. Elliott
WATER MANAGEMENT DIVISION

Westvaco Corporation
<u>North Charleston, South Carolina</u>

Dear Gayle:

Attached are copies of the metallographic report on the failed tube from the No. 2 Riley Boiler for your transmittal to the plant. This turned out to be just a case of corrosion fatigue with no evidence of caustic embrittlement. In addition to the information reported formally, I had Keith take a look at the microstructure under higher magnification and he reports lamellar pearlite on both the side of initial failure and 180° from the fracture line. This of course means [illegible]t the tube was not heated beyond the 900°F area for any signif[illegible]t time.

It [illegible] kind of hard to put together circumstances which would result in co[illegible]sion fatigue, but suppose that the steam generators in this boiler are delivering so much steam into the flooded drum that the top tw[illegible] rows of tubes were carrying nearly continuous quantities of steam up [illegible] the top drum and the third row (the failed tube) alternately carried [illegible]eam and then slugs of water. If this condition actually occurre[illegible] it could have caused a thermal cycle of 300 or 400° without exceed[illegible]g the 900°F limit. This would be enough to create fatigue and that, [illegible]oupled with film boiling that might occur during the steam portion [illegible]f the cycle, would create corrosive conditions that would focus at [illegible]e fatigue points.

If this was a case of strictly mechanical fatigue that resulted from the drums being firmly anchored and tube expansion, I would expect the cracks to be largely circumferential. The cracks in this tube are very random in both the circumferential and longitudinal directions. This does not rule out the mechanical possibilities, but I think does emphasize the thermal cycling as the fatigue mechanism.

MEMORANDUM

Gayle Starr
Charlotte, North Carolina

Gayle, all the above is pretty much of a guess and if you've got some ideas, I am sure that they have equal or better possibility of being correct.

REE/dh

cc: R. E. Elliott
cc: WMD File

CALGON CORPORATION
SUBSIDIARY OF MERCK & CO., INC.

CALGON CORPORATION CALGON CENTER BOX 1346 PITTSBURGH, PA. 15230 (412) 923-2345

CALGON LABORATORIES

WESTVACO CORPORATION

North Charleston, S. D.

SUBJECT: Failed Tube Section
Lab No. 4207, Received 11/25/74

A failed tube section from the No. 2 Riley Boiler was received for metallographic examination.

The failure, which consisted of a thick edged wide open burst, (Fig. #1) was located in an area where the inside wall surface of the tube was severely pitted. (Fig. #2) Several other short shallow cracks were located adjacent to the edge of the primary failure.

Specimens, removed from the edge of the failure and 180° from the failure, were mounted, polished, etched and examined microscopically. Photomicrographs were taken as follows:

1) Of the grain structure adjacent to the inside wall surface near the edge of the failure. (Fig. #3, 360X)

2) Of the grain structure near the edge of the failure midway between the interior and exterior wall surface. (Fig. #4, 360X)

OBSERVATIONS

The cracks were blunt, transgranular and originated on the inside wall surface. (Fig. #3)

The grain structure adjacent to the edge of the failure did not show evidence of plastic deformation (grain elongation). (Figs. #3 & #4)

CONCLUSION

It appears that a combination of corrosion and fatigue were the causes of failure as evidenced by the severe pitting on the inside wall surface and the blunt transgranular cracks. The lack of plastic deformation along the failed edge indicated that creep had not occurred.

H K Kolavick
H. K. Kolavick

R. L. Tempalski
R. L. Tempalski

December 17, 1974

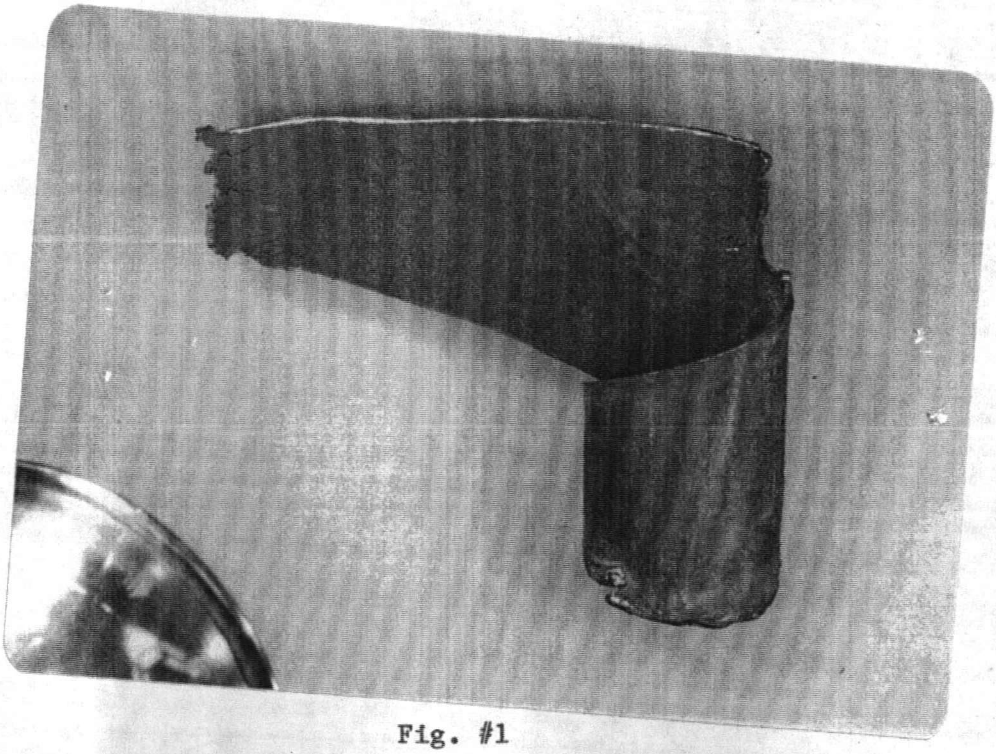


Fig. #1

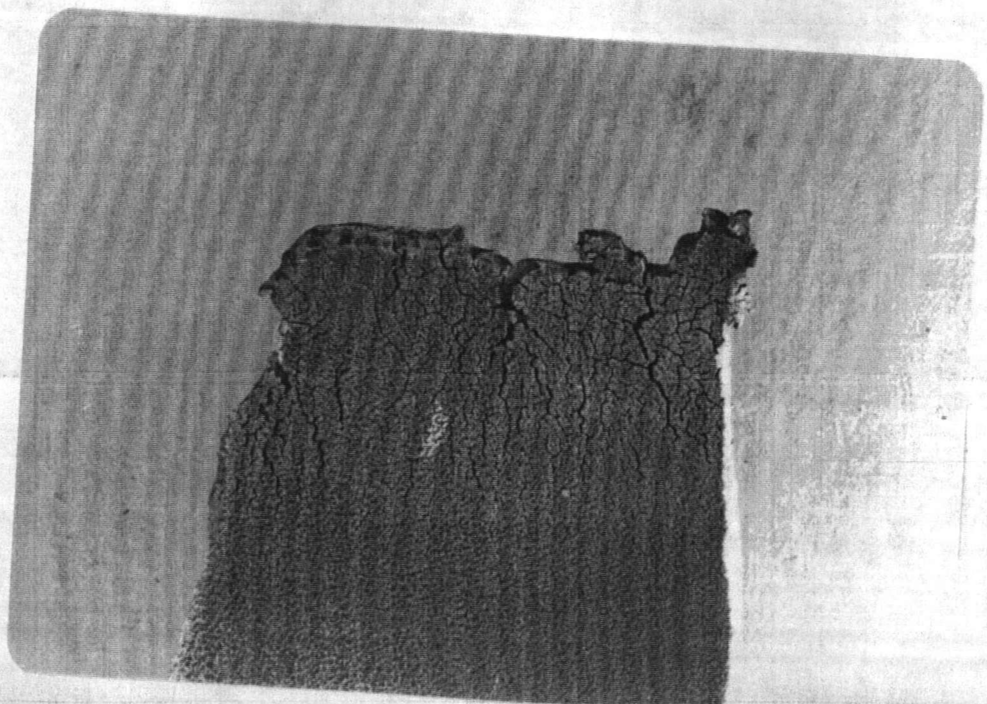
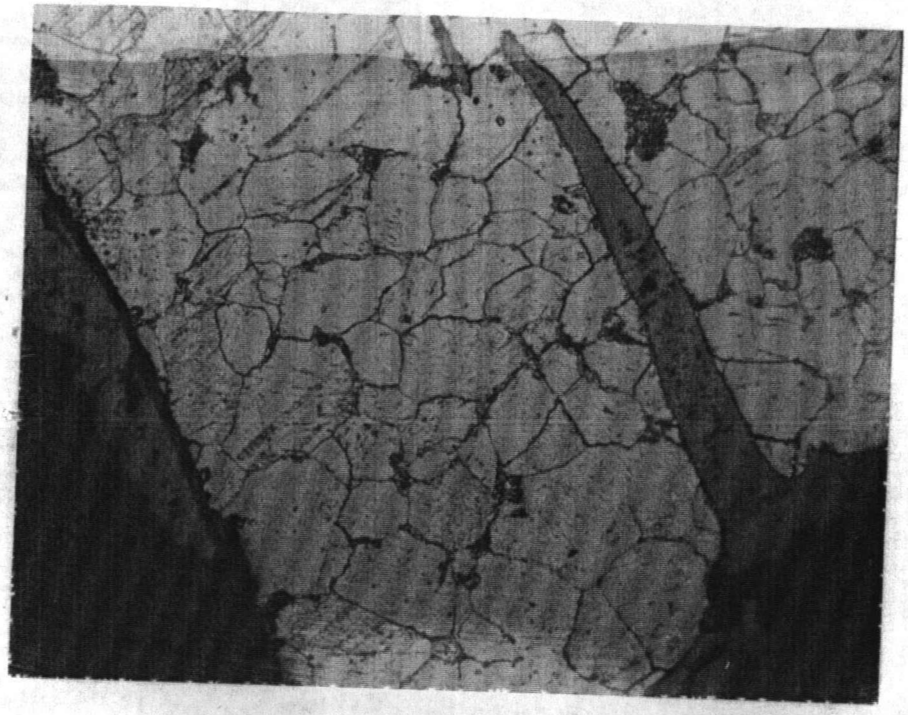


Fig. #2

Failed Edge



Inside wall surface

Fig. #3 Grain structure adjacent to the inside wall surface near edge of failure. 360X

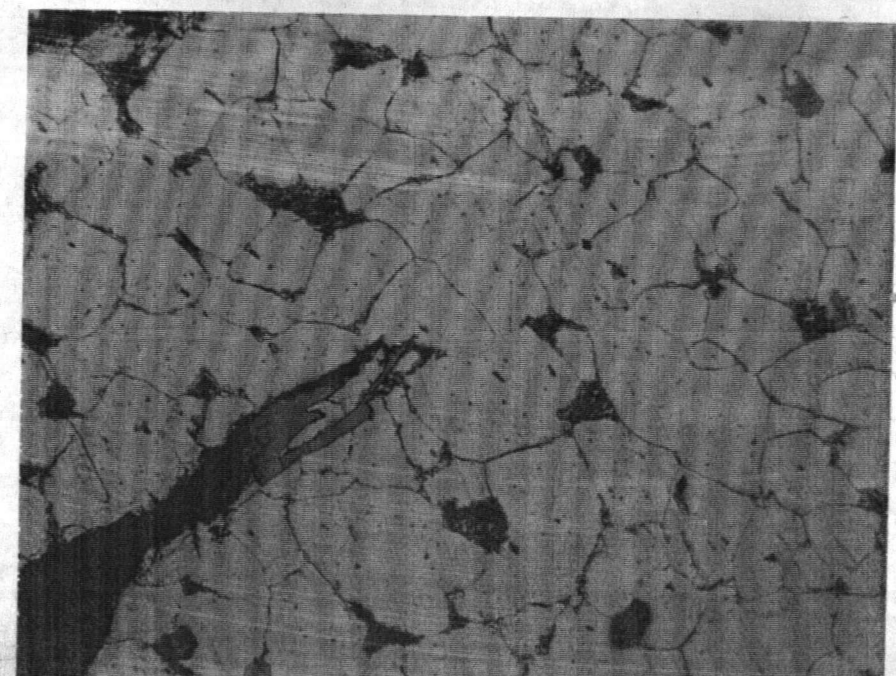


Fig. #4 Grain structure near the edge of failure midway between internal & external wall surface. 360X

Interpreting Graphitization for Power Engineers

By HELMUT THIELSCH

Metallurgical Engineer, Grinnell Company, Providence, R. I.

The power industry has been vitally concerned with graphitization ever since the brittle failure in a welded carbon-moly steel pipe in the main steam line at the Springdale Station of the West Penn Power Company in January 1943. The author presents a method for evaluating severity of graphitization and provides recommendations and techniques for rehabilitation.

BECAUSE severe graphitization reduces considerably the ductility and toughness of the affected areas, periodic examination of valve and pipe joints in high-temperature piping is essential to prevent costly failures and contingent danger to life and property. For example, a recent routine examination of a main steam line of a power plant revealed a 1 in. deep crack around the circumference of a $1^3/_4$ in. thick valve-to-pipe joint. This crack, illustrated in Fig. 1, is in the heat-affected zone of the valve, parallel to and approximately $^1/_{32}$ in. away from the weld metal. Examination under the microscope established that this cracking occurred in a severely graphitized zone which is shown in Fig. 2. Further embrittlement and propagation of the crack might have resulted in a very serious failure in the main steam line. This valve has been replaced to remove this hazardous condition.

Graphitization is associated primarily with carbon steels in long-time service above 800 F and carbon-molybdenum steels above 900 F. Rolled, forged or cast materials prepared by a high-aluminum deoxidation practice (over $1^1/_2$ lb Al per ton of steel) usually are considered highly susceptible to graphitization. The low-aluminum deoxidized grades (less than $^1/_2$ lb Al per ton of steel) are considered fairly resistant to serious graphitization, although they are not always completely immune. In fact, a recent investigation of a coarse-grained, silicon-killed steel used in a petroleum refinery installation showed heavy graphitization. In a steam power system serious graphitization in a silicon-killed steel so far has been found only in one installation. Thus, it is advisable to examine periodically silicon-killed steel piping.

Fig. 1—Crack in graphitized zone on valve side of "weld-probe" specimen in valve-to-pipe joint. Pipe on left and valve on right. (Because of dimensions of valve, the specimen was removed by drilling out)

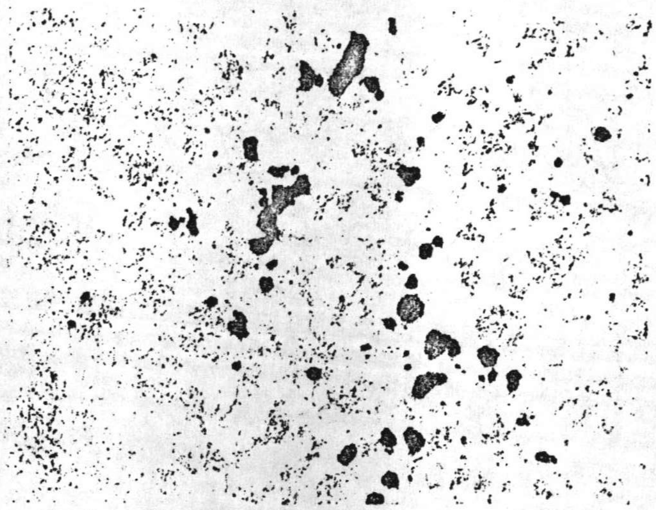


Fig. 2—Photomicrograph of the graphitized zone in the cracked valve material shown in Fig. 1. Heat-affected zone on left; base metal on right (500×)

Thus far $^1/_2$ Cr-$^1/_2$ Mo materials have shown resistance to graphitization in service up to at least 950 F. Similarly, the 1 Cr-$^1/_2$ Mo and $1^1/_4$ Cr-$^1/_2$ Mo grades appear to be resistant up to about 1050 F, although at these temperature levels very limited service data are available to date.

Rolled and forged carbon, carbon-moly and $^1/_2$ Cr-$^1/_2$ Mo steels, from which pipe for steam power systems is fabricated, are now made by the steel mill with a deoxidation practice which limits the maximum permissible aluminum addition to $^1/_2$ lb Al per ton of steel.

Cast steels, as used in valve bodies of carbon and carbon-moly steels, generally are made by a melting practice with 2 lb or more aluminum per ton of steel. The main reason for this is that under ordinary foundry conditions this amount of aluminum is necessary to prevent gas formation in the molds. Although a few foundries have been able to limit the aluminum addition to $^1/_2$ lb Al per ton of steel, the resulting castings

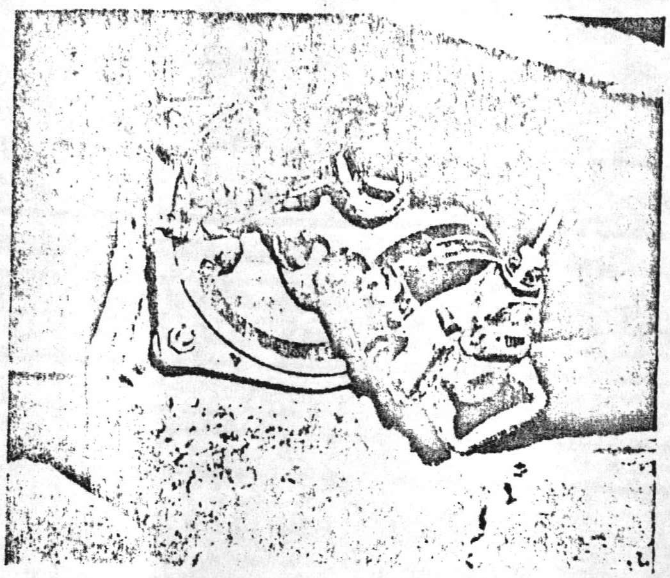


Fig. 3—"Weld-prober" saw in operation removing boat-shaped specimen from pipe-to-valve joint

Fig. 4—Appearance of piping after removal of boat-shaped weld-probe specimen from pipe-to-valve and pipe-to-saddle joints

may be considerably more expensive. Since the addition of $1^1/_4$ per cent chromium and $^1/_2$ per cent molybdenum is likely to inhibit serious graphitization, it is usually economical to specify chrome-moly alloy valve materials.

Since castings, as a general rule, are likely to contain more carbon and aluminum than the corresponding grades of wrought or forged piping materials, the periodic inspection of carbon and carbon-moly valve materials is particularly important.

Metallurgical Considerations

Graphite is free carbon which has little strength, very low ductility and very low resistance to mechanical or thermal fatigue or shock. The physical metallurgist considers its formation as a nucleation and growth process which takes place on long-time exposure at temperatures above 800 F. Graphitization is the result of the diffusion and coalescence of atomic carbon in solution in the steel matrix and the decomposition and diffusion of iron carbide (cementite) into ferrite and free carbon and the subsequent diffusion and coalescence of the latter.

When the graphite occurs in form of nodules distributed at random throughout the steel matrix, its effect upon the mechanical properties of the steel is rather insignificant. However, where the graphite segregates in clusters of nodules along zones or forms continuous chains, the mechanical properties in the affected area may be considerably or even seriously reduced.

A narrow band of particularly unstable carbide and ferrite supersaturated with carbon tends to occur at the extremity of the heat-affected zone in the region where the temperatures resulting from the welding operation reach approximately 1325 to 1425 F for a very short time. Subsequent prolonged service above 800 F may cause particularly severe graphitization in this zone, usually about $^1/_{16}$ to $^1/_8$ in. from the weld.

The degree of graphitization depends primarily upon the composition and thermal history of the steel. For the same type of steel, an increase in the carbon content would tend to increase the amount of graphite that may form.

Alloying or residual elements, which tend to form carbide particles, inhibit graphitization. Thus, chromium, molybdenum, manganese and vanadium are beneficial. If present in a sufficiently large quantity, these elements may prevent graphitization. However, some of these elements may be undesirable because of their effects upon the welding characteristics of the steel.

Sampling

Because of the severe consequences of failures in steam power systems, many power companies have in the past checked, and are periodically checking, the condition of welded joints in pipe and valve materials susceptible to graphitization.

The method most widely used consists of removing boat-shaped slices from welded joints by means of the so-called "weld-prober," illustrated in Fig. 3. The slice is taken across the weld and should include at least $^1/_2$ to 1 in. of base metal at each side of the weld. Typical examples are illustrated in Fig. 4. When properly prepared, the weld-probe slice provides sufficient material for a metallographic examination and one bend test. Fig. 5. Pipe or valve sections of such dimensions as to make attachment of the weld-prober impossible may

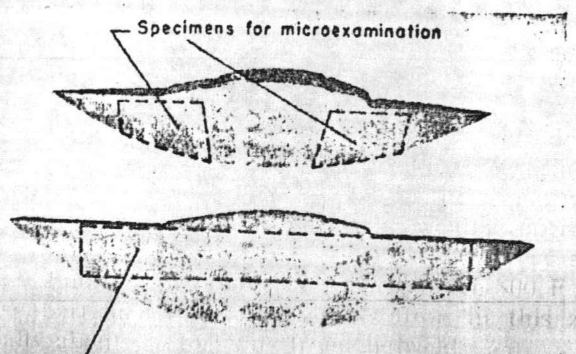


Fig. 5—Sections for bend testing and metallographic examination

require special sectioning procedures, as trepanning or drilling (see Fig. 1).

Upon removal of the slice from the pipe, the cavity is filled by arc welding, Fig. 6. This is often followed by a metallurgical heat treatment, usually at stress-relieving temperatures. Where rehabilitation of the piping system is contemplated, the heat treatment may be omitted or deferred until the weld-probe specimen has been examined. For example, if graphitization is found to be sufficiently severe to necessitate immediate rehabilitation of the affected joints, the final metallurgical heat treatment would also place the joint into the proper stress-relieved condition, as required by the various Codes.

For economic reasons, only one specimen is ordinarily removed from the weld joint. However, since the amount and type of graphitization may vary around the circumference of the pipe joint, the removal of two or three specimens is advisable—particularly where moderate to severe graphitization is suspected. In particular, in cast valve steels where deoxidation was made in the runner box, the aluminum distribution tends to be non-uniform. The resulting differences in the stability of the metallurgical structure may cause a considerable variation in the "degree" of graphitization.

Although it may often be sufficient to examine only one end of a pipe, differences in the stress, welding and post-heating conditions may have resulted in different "degrees" of graphitization at each pipe end, so that sampling of both ends is advisable. On cast valve steels, it is particularly desirable to examine both ends because of the greater possible variation in the composition of the material.

Fig. 6—Rewelded area of sampled cap-to-header joint in steam header. Upper, with preheating coils and deposit of initial root pass; lower, completed weld (which has been stress relieved)

Grading Graphitization

Since the degree of severity, (i.e., the level of safety of each joint in a steam power system), depends upon the form, shape and distribution of the graphite particles, a relative classification is not readily accomplished. Also, there is no sharp delineation between "severe" and "moderate" graphitization.

The photomicrographs and bend tests obtained from a weld-probe specimen leave room for considerable latitude of interpretation. Careful analysis of such additional operational factors as temperature and pressure cycling, thermal or mechanical fatigue and shock, external loading, section thickness, etc., is also necessary. When of significant magnitude, these factors may contribute to a reduced level of safety of mild or moderately graphitized piping.

On the basis of the 10 years of research in the laboratories of the Grinnell Company, a grading system of graphitized zones has been established which is illustrated in Fig. 7.

The microstructures shown in Fig. 7 generally correspond to the following bend angles (test strips bent to the point where a $^{1}/_{16}$ in. long crack is first observed in the heat-affected zone):

Graphite Observed in Microstructure	Bend Angle
Mild	Over 90°
Moderate	45–90°
Heavy	30–45°
Severe	15–30°
Extremely severe (dangerous)	Below 15°

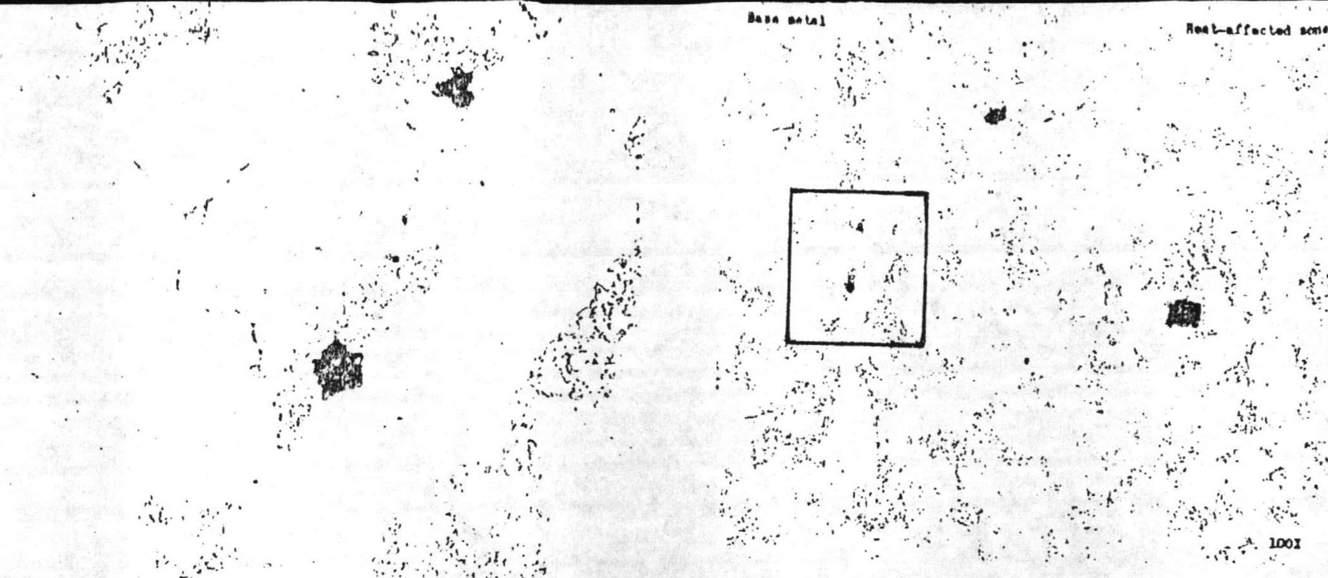
Obviously, the "degree" of graphitization may fall between these gradings.

Rehabilitation

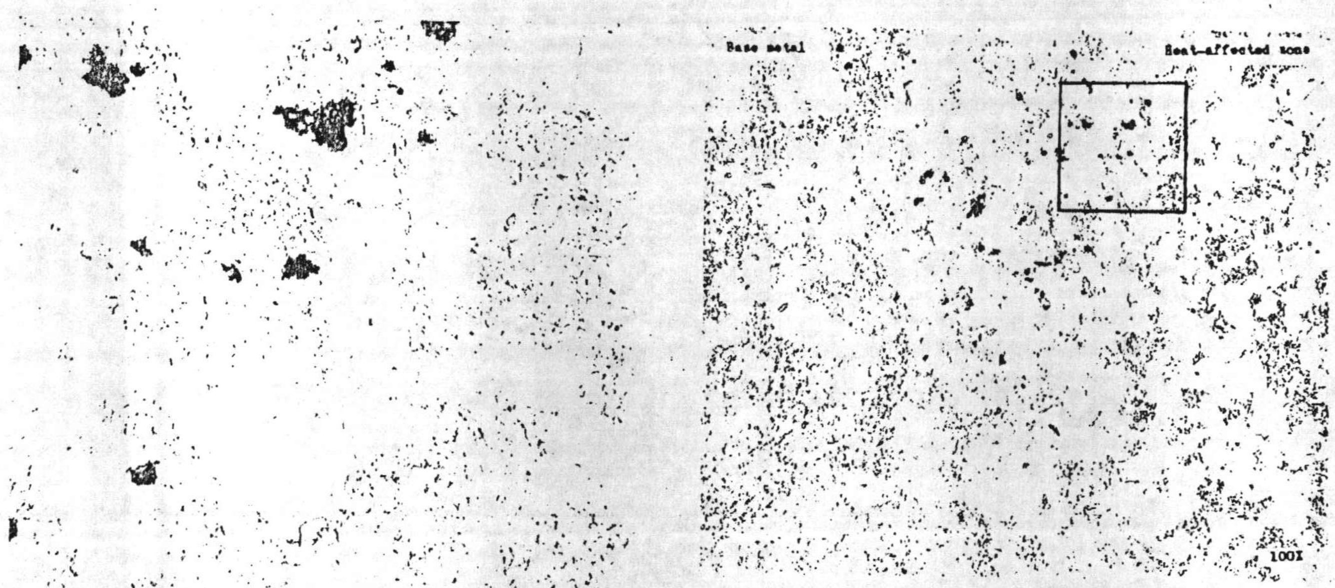
Where significant quantities of graphite have been found in the heat-affected zone in piping or valve materials to warrant concern, several procedures have been employed to restore the steam power system to a safer operating condition. These are:

1. Solution heat treatment.
2. Removal of graphitized area in the heat-affected zone by (*a*) partial or (*b*) complete grooving out and rewelding.
3. Replacement of graphitized pipe or valve sections.

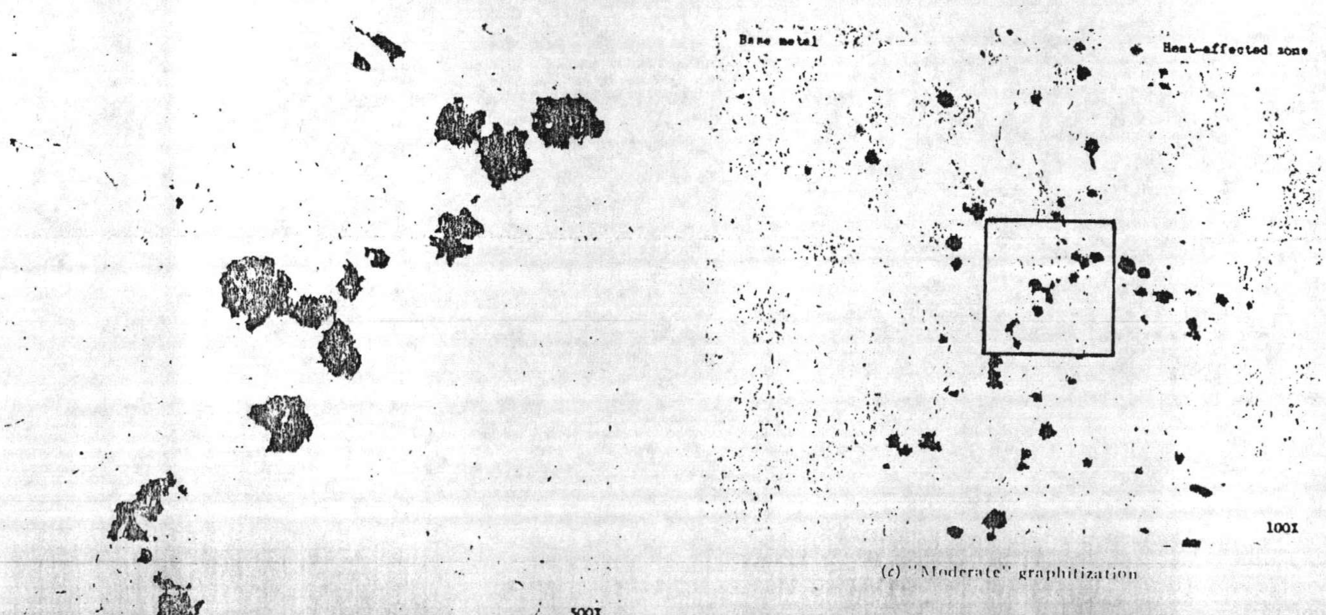
The choice of the proper procedure depends primarily upon the degree of graphitization, the estimated future life and operating conditions of the particular power system and certain economic factors. Sometimes moderately or even heavily graphitized pipe or valve joints which do not show cracking are temporarily rehabilitated by the solution heat treatment until the next shutdown of the steam power system, or until replacement pipe or valve sections can be obtained. It is important to



(a) "Very mild" graphitization.

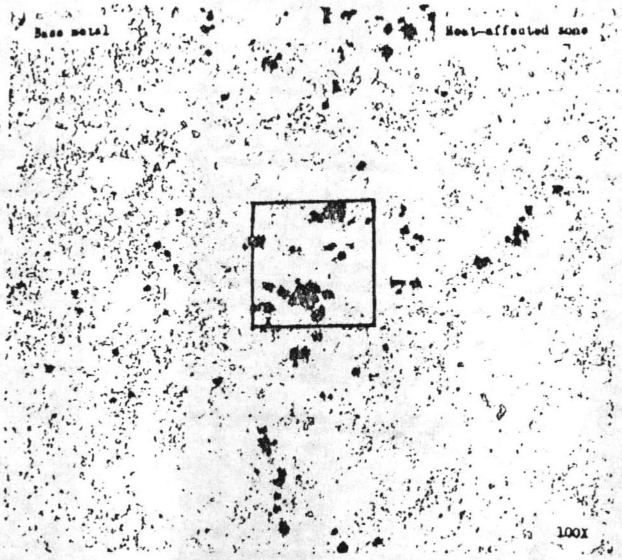


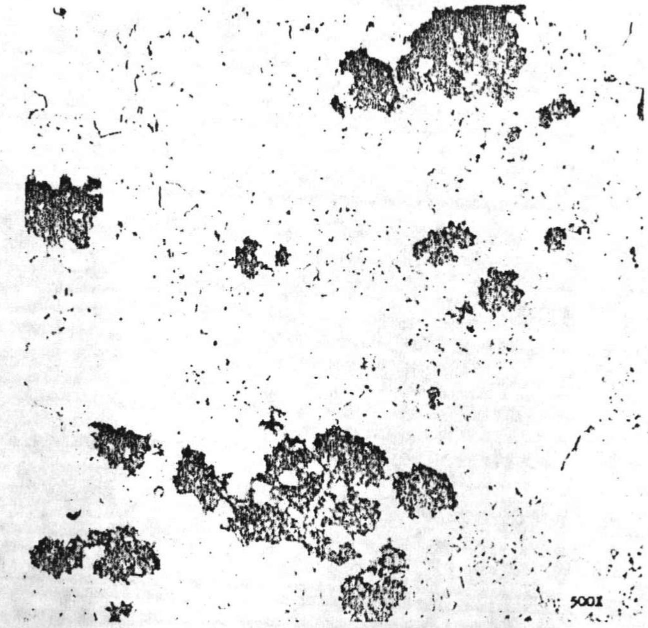
(b) "Mild" graphitization.



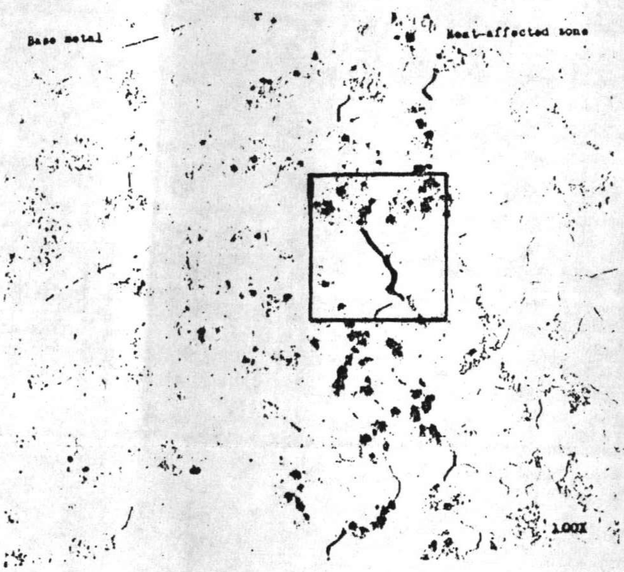
(c) "Moderate" graphitization

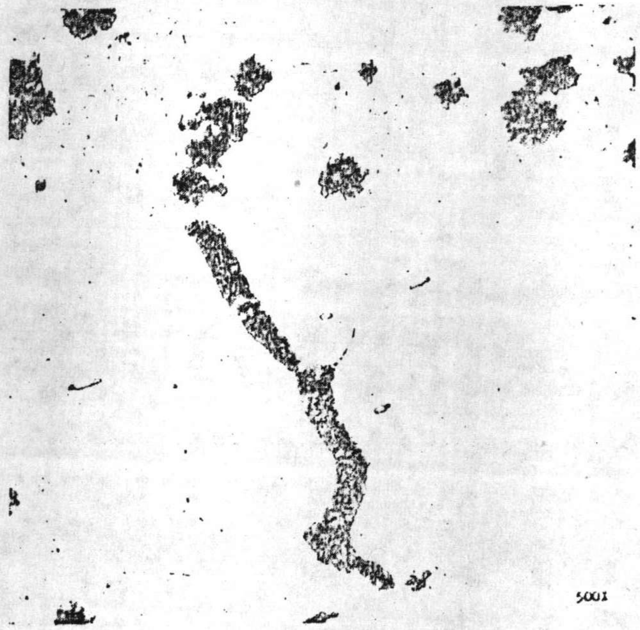
Fig. 7—Microstructures at 100 and 500 diameters



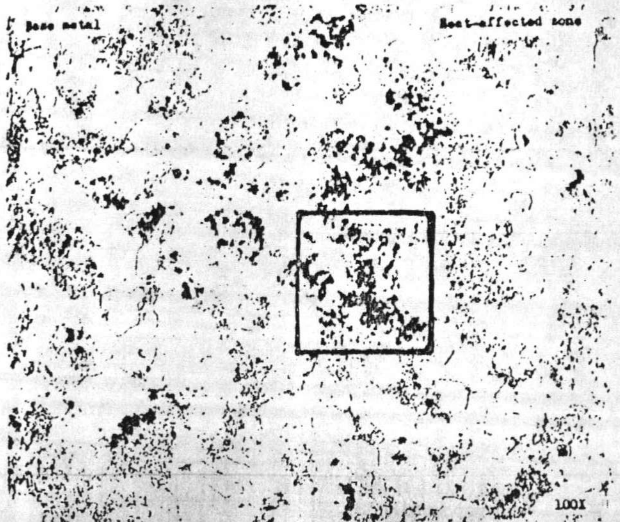


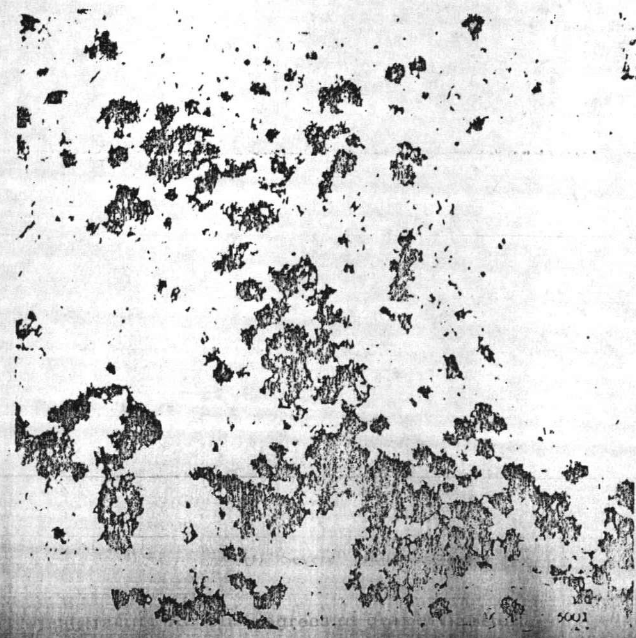
(*d*) "Heavy" graphitization.





(*e*) "Severe" graphitization.





(*f*) "Severe" graphitization.

illustrating various degrees of graphitization

rewelding procedure serve only as temporary cures.

The continuous use of materials susceptible to graphitization should be accompanied by periodic examination of weld-probe specimens to study the progress of graphitization. The results of such periodic studies also assist in the selection of a suitable rehabilitation procedure.

Solution Heat Treatment

The solution heat treatment consists of heating the graphitized area to above the upper critical (transformation) temperature of the steel. At these temperatures the "ferritic" steel has transformed into an "austenitic" steel in which the graphite will dissolve. Upon subsequent cooling, the carbon will again be in "solution" or will form cementite particles. A commercial solution heat treatment consists of heating for two to four hours at temperatures between 1700 and 1750 F, depending upon the type of steel and the degree of graphitization. This is followed by controlled cooling to 1000 F at a rate of 300 to 400 deg F per hr.

The major advantage of this procedure is that it is less costly than rewelding or the replacement of pipe or valve sections. However, where long operating periods of five, ten or even more years are involved, the solution heat treatment provides, at best, only a temporary cure. It is generally accepted that graphite will re-form more rapidly and in less time in the solution heat-treated, heat-affected zone than it did in the original stress-relieved weld. It is also believed that the solution of graphite during the solution heat treatment leaves small voids in the steel matrix. These voids continue to act as local stress raisers so that the solution heat treatment does not improve materially the ductility and toughness over that of the previously graphitized area. Thus, subsequent regraphitization during service is likely to further weaken the material. For these reasons the solution heat treatment is now rarely, if ever, recommended.

One large utility company, having first solution heat treated one steam power system, decided subsequently to cut out all welds and heat-affected areas and reweld the entire system. Rewelding in the first place would have been considerably less costly.

Rewelding of Graphitized Area

In this procedure the graphitized area is first removed by flame or arc grooving and/or grinding and is rewelded follow the welding operation.

In the case of moderate graphitization, partial removal of the graphitized area may be adequate. The groove is cut to about $^1/_{16}$ in. from the backing ring on the inside diameter of the pipe or valve. Where graphitization has occurred only on one side of the weld, as may be the case in the valve side of pipe-to-valve joints, the procedure illustrated in Fig. 8 should be followed. Where graphitization has occurred on both sides of the weld, the recommended procedure is illustrated in Fig. 9. The new groove is approximately $^1/_3$ to $^1/_2$ wider than the original groove.

The advantage of this procedure is that fit-up, groove protection and back-up are not required. Of course, proper supporting of the piping is essential in order to prevent cracking in the weld area and not disturb the cold spring (prestress) in the pipe line at room temperature. It must be realized that a small zone of graphitized steel remains at the root of the new weld deposit.

Where the degree of graphitization has been sufficiently heavy to reduce seriously the ductility and toughness in the graphitized area causing cracking to occur in bend specimens at an angle of less than 45 deg, it may be advisable to remove completely the heat-affected and weld areas. The cut ends should then be pulled together, fitted-up and rewelded as illustrated in Fig. 10. In rigid systems it may be desirable to build up the groove faces with weld metal (sometimes called "buttering") and grind to obtain a standard edge preparation prior to the final welding operation of the two ends.

Where necessary, suitable pipe sections should be inserted, preferably of $^1/_2$ Cr-$^1/_2$ Mo, 1 Cr-$^1/_2$ Mo or 1$^1/_4$ Cr-$^1/_2$ Mo steel to replace one or several removed sections, as illustrated in Fig. 11. Generally, the 1$^1/_4$ Cr-$^1/_2$ Mo grades are most readily available.

In due time graphitization may reoccur in the new heat-affected zones adjacent to the weld. Depending upon the materials involved and the postheating cycle, the rate of graphitization in the new heat-affected zones may be reduced considerably. If the estimated safe operating life exceeds the planned operating life of the steam power system, the rewelding procedure may well be the most economical.

Replacement of Pipe or Valve Sections

In pipe or valve materials which are very susceptible to graphitization and which show graphite in the pipe

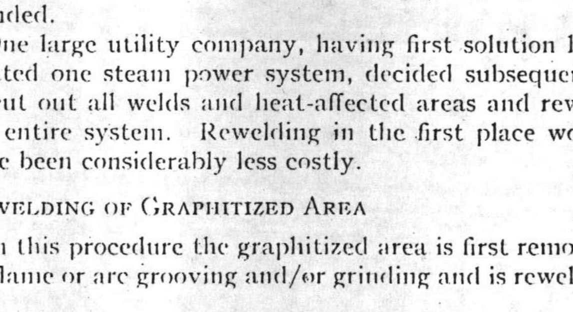


Fig. 8—Sketch illustrating procedure for partial grooving out and rewelding of joint with graphitization on one side of the weld

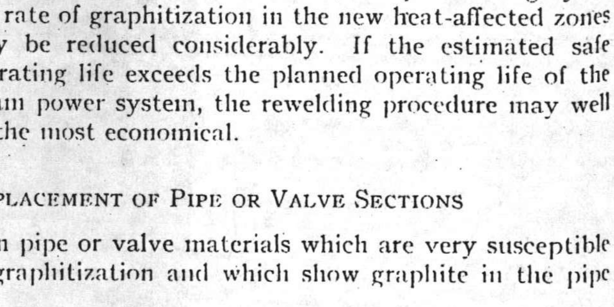


Fig. 9—Sketch illustrating procedure for partial grooving out and rewelding of joint with graphitization on both sides of the weld

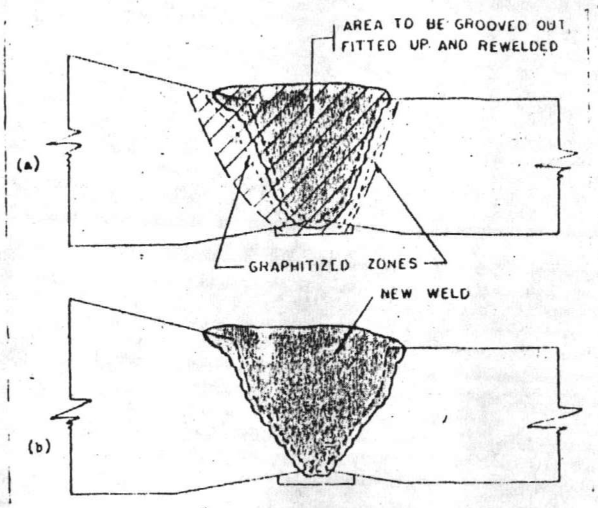


Fig. 10—Sketch illustrating procedure for complete (*a*) grooving out and (*b*) rewelding of joint with graphitization on both sides of the weld

or valve metal as well as serious graphitization in the heat-affected zone, it may be advisable to replace completely the graphitized components. Bend specimens which fail at an angle of less than 15 deg usually indicate that the degree of graphitization is extremely severe.

Where pipes and valves are replaced, the use of $^1/_2$ Cr-$^1/_2$ Mo, 1 Cr-$^1/_2$ Mo or $1^1/_4$ Cr-$^1/_2$ Mo materials should be considered. The replaced sections are not likely to give further graphitization troubles. Little or no further sampling is required. Moreover, improved design and fabrication practice of present-day piping and valve systems results in lower pressure drops and higher quality joints so that higher efficiencies and lower maintenance can be obtained.

Postheat Treatment

After the welds have been completed, a metallurgical heat treatment is generally employed which consists of heating the weld area to 1300 to 1350 F for four hours. This heat treatment retards future graphitization. Reoccurrence of graphite in carbon-moly pipe welds when heat treated in this manner, if at all, usually is in the widely scattered nodular form. Subsequent heavy graphite concentrations in the heat-affected zone are rarely found.

Recommending Rehabilitation

Rehabilitation by (1) removal of graphitized area in heat-affected zone by (*a*) partial or (*b*) complete grooving out and rewelding or (2) the replacement of graphitized pipe or valve sections is usually advisable where the degree of graphitization is found to be heavy, severe or extremely severe. Because the most suitable method varies with each particular steam power system, a definite recommendation cannot be made on the basis of a laboratory examination alone. The proper method can be determined only after a careful review and evaluation of the economic and operational factors such as operating and peak temperatures and pressures, cycling, thermal or mechanical fatigue and shock conditions, expected service life, retirement of the particular steam power unit, etc. The overall condition of the whole steam power unit must be considered also. If many joints show "heavy" graphitization, it may be

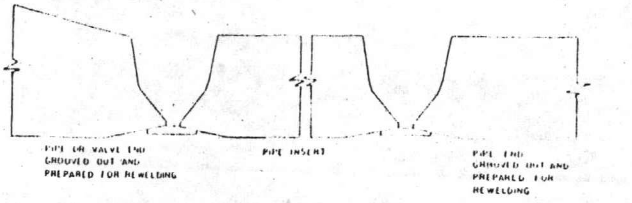


Fig. 11—Sketch illustrating inserting of pipe section to compensate for several weld joints completely grooved out, pulled together, fitted-up and rewelded

advisable to cut out completely the respective weld joints and heat-affected zones as illustrated in Fig. 11. Where only one joint shows "heavy" graphitization, partial grooving out and rewelding may be sufficient.

For the purpose of illustration only, example recommendations are given below for a particular steam power system. The following operational characteristics are assumed for this hypothetical installation:

Total operation	100,000 hr
Expected future operation	150,000 hr
Operating temperature	890–915 F.
Operating pressure	970–980 psig
Shutdowns	2 per year
Conditions for severe thermal shock	Negligible
Exposure to mechanical vibrations	Negligible
Piping material	Carbon-moly (ASTM A206)
Deoxidation practice	2 lb aluminum per ton of steel
Pipe size	12 in. nom. ($12^3/_4$ in. OD)
Wall thickness	1.3 in. (schedule 160)

The following recommendations might be made:

Degree of Graphitization	Recommended Rehabilitation
None	Take another weld-probe specimen after 20,000–30,000 hr of service.
Mild	Take another weld-probe specimen after 8000–10,000 hr of service.
Moderate	Gouge out (partially) heat-affected zone and reweld.
Heavy	Cut out (completely) heat-affected zone and reweld.
Severe	Replace respective piping or valve materials at next scheduled shutdown. Check affected materials for cracks.
Extremely severe	Present condition of material extremely hazardous. Check for cracks, make immediate repairs and replace materials as soon as replacement sections can be obtained.

Where a system is subject to severe thermal or mechanical shock, the above recommendations might include radiographic and magnetic particle inspection of the steam power system.