Appendix B

Corrosion Test Work

"Heat Pipe Corrosion Test -- EPRI/NYSEG HSTC Unit," ABB API Report to NYSEG, EPRI, and Radian Corporation, New York State Electric & Gas Corporation, Binghamton, New York, January 6, 1994.

McCoy, D. C., Weinheimer, U., Janik, G. S., and Marker, B., "Milliken Unit 2 ESP And Slipstream Heat Pipe Corrosion Tests, July 15, 1993 to May 21, 1994," Joint NYSEG/CONSOL Final Report, Research and Development Contract No. 95-149, New York State Electric & Gas Corporation, Binghamton, New York, August 1995.

Heat Pipe Corrosion Test Report
EPRI/NYSEG HSTC Unit

Report prepared by ABB API for NYSEG, EPRI, and Radian Corporation.

Report transmitted by cover letter from Mr. S. F. Harting (ABB API) on January 6, 1994 to Dr. G. S. Janik (NYSEG), Mr. K. Zammit (EPRI) and Mr. A. J. Mechtenberg (Radian).

Heat Pipe Corrosion Test

EPRI/NYSEG HSTC Unit

INTRODUCTION

The Electric Power Research Institute (EPRI) installed a pilot scale selective catalytic reduction (SCR) unit for nitrogen oxides (NOx) removal on the exit duct from the flue gas desulfurization (FGD) unit at New York State Electric and Gas Corporation's (NYSEG) Kintigh Station electric power plant. The purpose was to test the feasibility of NO_x removal after the FGD unit. Part of the SCR system is a heat pipe unit that is used to transfer heat from the 610°F SCR exit gas to the 125°F SCR inlet gas.

Early inspections of the heat pipe unit revealed severe corrosion was occurring. This opportunity was used to test additional heat pipe materials of construction in the flue gas environment at the Kintigh Station.

ABB Air Preheater, Inc. (ABB API) fabricated two sets of three heat pipes using different materials. Carbon steel, Cor-Ten B®, and AL-6XN® were the materials selected for this limited test. CONSOL installed one set of heat pipes in front of Module 1 and one set after Module 1 in the heat pipe unit (see Figure 1) in November 1992. The set of test heat pipes installed in front of module one (Location A) were filled with Freon® 11 (see Figure 2) and the heat pipes installed after Module 1 (Location B) were filled with toluene (see Figure 3). The heat pipes were inspected during scheduled outages and inspection reports are available.

After the May 17, 1993 inspection, the two sets of test heat pipes were removed and destructively tested. The preliminary corrosion data were presented at a meeting on June 16, 1993, at the Kintigh Station. At this meeting, it was decided to destructively test one of the original alloy 2205 heat pipes. This pipe was removed and shipped to ABB API for the evaluation.

This report documents the results of the destructive testing on the two sets of test heat pipes and the one original heat pipe.

CONCLUSIONS

1. None of the tested or original tube materials can provide a 20-year life heat pipe in the Kintigh Station environment at Location A, return side. This is predicated on a standard 0.100" wall thickness.
2. Alloy 2205 tube exhibited the lowest corrosion rates. There may have been anodic protection by the AISI 409 stainless steel fins (See Discussion).
3. AL-6XN® exhibited low corrosion rates and a localized pitting/cracking phenomena at Location A, return side.

4. Cor-Ten B® exhibited a relatively high corrosion rate at Location A, return side.
5. The carbon steel exhibited high corrosion rates at Location A, return side.
6. Carbon steel exhibited an unacceptable corrosion rate at Location A, supply side and a marginal corrosion rate at Location B, return side (See Discussion).
7. All materials showed acceptable corrosion rates at Location B, supply side.
8. AL-6XN® exhibited a marginal corrosion rate at Location B, return side.

RECOMMENDATIONS

1. Use nickel base alloy tubes. There is information that Alloy C-276 has an acceptable corrosion rate in similar atmospheres.
2. Use alloy 2205 or Cor-Ten® tubes in a removable cold end module.

RESULTS

Visual Observations

1. Location A

   Flue gas temperature - Supply Side 125°F

   Return Side 240°F

   All of the heat pipes exposed at Location A are shown in Figure 4.

   The carbon steel and the Cor-Ten B® heat pipes exhibited severe rusting on the return (evaporator) side. The carbon steel heat pipe exhibited a longitudinal "grooving", (see Figures 5 and 6). The AL-6XN® heat pipe exhibited pitting damage (see Figure 7). The pitting and corrosion damage formed a pattern that approximated the fluid level in the heat pipe (see Figures 4 and 8).

   On the supply side (condenser), the carbon steel exhibited significant rusting (see Figure 9) while the Cor-Ten B® and AL-6XN® exhibited very little to no corrosion (see Figures 10 and 11).

2. Location B

   Flue gas temperature - Supply Side 215°F

   Return Side 340°F

   The set of heat pipes exposed at Location B are shown in Figure 12.

   For the return side, the carbon steel pipe was rusted (see Figure 13). The Cor-Ten B® pipe was rusted in spots with a tightly adherent scale over much of its surface (see Figure 14). The AL-6XN® pipe had corroded to a matte finish with a stain indicating the fluid level in the pipe (see Figures 12 and 15).

The supply side materials exhibited little to no corrosion (see Figures 16, 17, and 18).

3. Alloy 2205

   This heat pipe had severely corroded fins; however, the tube material appeared to have suffered little corrosion. The fins on this heat pipe were AISI 409 stainless steel. When the fins were removed from a section of return side tubing, the tube exhibited varying degrees of corrosive material removal between the fins. Figures 19, 20, 21, and 22 show this attack about the diameter of the tube.

   When the fins were removed from a section of supply tubing, it was noted that there was pitting corrosion around the outer diameter of the tube. This pitting did not have a pattern around the tube, it was associated with deposits that had built upon the tube. Figure 23 shows the pitting on the tube.

Corrosion Measurements

The test heat pipes were drained and sectioned for corrosion measurements. Short tube lengths were cut from each test heat pipe. The thickness of each length was measured with a micrometer. These results are reported in Table 1.

The alloy 2205 heat pipe was drained and sectioned. Samples were prepared metallographically for the finned areas and underneath the mounting collar. Figure 24 shows the locations of the metallographic sections. These sections were measured optically using a microhardness tester (see Figures 25 and 26). The ends were sectioned from the heat pipe and measured with a micrometer (see Table 2),

Microscopic Observations

Sections of the test heat pipes were examined. No unusual microstructures or discontinuities were found in the carbon steel or Cor-Ten B® samples. The AL-6XN® material exhibited pitting and cracks emanating from the pits in the sections taken from the return side, Location A (see Figures 27 and 28). The samples from the AL-6XN® tube installed in Location B did not exhibit any unusual microstructures or discontinuities.

The return side of the alloy 2205 heat pipe showed a preferential corrosive attack between the fins (see Figure 29). The fin-to-tube braze joints were not complete and exhibited cracks (see Figure 30).

The supply side of the alloy 2205 heat pipe showed pitting attack (see Figures 31, 32, and 33). The ferrite exhibited a greater corrosion attack than the austenite in the 2205 alloy. Figures 32 and 33 show the attack. Pit depths ranged from 0.0011" to 0.005".

Weight Loss

The six ABB API heat pipes and their flanges were weighed prior to installation. This was to allow for a weight loss measurements after exposure.

When the tubes were installed and removed, the welding and cutting operations damaged the flanges or added significant quantities of weld metal to the heat pipes.

The removed tubes were weighed; however, the data is not reported due to the inaccuracies.

The weight of a section of bare alloy 2205 tube was determined mathematically and compared to weight of a length of corroded tube from supply side. The comparison yielded a corrosion rate of 5.6 mpy.

DISCUSSION

Three different materials were exposed to a desulfurized, deNO_xed flue gas stream at the Kintigh Station. The test areas in the heat exchanger were chosen to represent the worst case in terms of dewpoint corrosion. The AL-6XN® corroded in both locations. The Cor-Ten B® corroded in Location A. The carbon steel corroded severely in Location A and slightly in Location B. Alloy 2205 corroded at both locations.

At Location A return side of the heat exchanger, the temperatures are well below the dewpoint. The two probable corrodants condensing are ammonium bisulfate (ABS) and sulfuric acid. ABS is formed from the unreacted ammonia and SO_3 in the flue gas. Excess ammonia is added to the gas stream to catalytically react with the nitrogen oxides. Sulfuric acid is formed by the reaction of SO_3 with water. Although, the flue gas has been desulfurized, quantities of SO_2 and SO_3 are present in the flue gas. The catalyst for the deNO_x process will convert some of the SO_2 to SO_3, thus increasing the quantity of SO_3 available to react with ammonia or water. Corrosion products from the unit indicate that ABS and sulfuric acid are actively corroding the unit.

In Location A, the carbon steel heat pipe corroded in both the deSO_x-deNO_x gas stream, return side, and the deSO_x gas stream, supply side. The heat pipe "grooving" in the return side location appears to be the result of liquid collecting on the surface and subsequent transport on and around the heat pipe. The corrosion at the end of the carbon steel heat pipe at Location A, supply side is attributed to the build up of noncondensable gases in the end of the heat pipe (see Appendix A). The water laden mist carried over from the flue gas desulfurization unit would collect on the cold tube and cause rusting. This corrosion was exacerbated by an air leak from one of the access doors in the unit.

The Cor-Ten B® heat pipe corroded at rates up to 42.3 mpy at Location A in the return side. The corrosion was fairly uniform about the diameter of the heat pipe.

At Location A, return side the AL-6XN® heat pipe corroded at a maximum rate of 10.6 mpy. In addition, this material exhibited cracking from the bottom of pits in the material. This transgranular cracking phenomena was not thoroughly investigated but probably is stress corrosion cracking. However, due to this cracking, the material cannot be used in this service. Pit depths and crack lengths are irrelevant with type of cracking. Both pitting corrosion and stress corrosion crack mechanisms are not predictable with time.

The alloy 2205 heat pipe was taken from the face of Module 1 closest to the Location A test area, i.e., the coldest row of the return side. Sections through this heat pipe showed corrosion rates of the tube material up to 9.7 mpy. The AISI 409 fins were corroding at rates up to 17.5 mpy. The corrosion patterns on the alloy 2205 heat pipe indicate that a flow related phenomena is affecting the tube. This could be by acid droplet impingement and collection by gravity, the effects of water washing, or crevice corrosion under a scale/deposit. Water washing effects would be expected to produce a more uniform corrosion. A combination of acid droplet impingement and a scale/deposit to hold the acid in contact with the tube is a likely cause. In any case, the 9.7 mpy corrosion rate is unacceptable for a 20-year life.

A galvanic couple is formed by the AISI 409 fins and the alloy 2205 tube. The galvanic action is further complicated by the nickel braze alloy. The AISI 409 material is the most galvanically active material and will corrode preferentially to the nickel braze alloy and the alloy 2205. This assumes that the tube and fins are covered with a liquid film to promote galvanic corrosion.

It is interesting to note that the finning vendor for ABB API experimented with an alloy 2205 fin on alloy 2205 tubing. The fin material cracked during application. Care must be exercised when selecting the finning material for alloy 2205. Ductility and galvanic corrosion must be considered.

All of the materials are unacceptable for a 20-year life in the Kintigh $deSO_x$-$deNO_x$ environment at Location A, return side.

In Location B, return side, the test materials exhibited lower corrosion rates, in fact the visual appearance of the Cor-Ten B® sample was such that it was not necessary to section that test heat pipe because the corrosion scale that forms to protect the Cor-Ten® was intact over 95% of the pipe's surface. The maximum corrosion rates were 7.9 mpy for the carbon steel and 5.3 for the AL-6XN®. The AL-6XN® sample did not exhibit any cracking. In the Table 1 corrosion data for AL-6XN®, the data scatter indicates that the corrosion measurement may be inaccurate due to measurement inconsistencies or tube wall thickness variations.

Although the supply side corrosion results are of no concern for the design of the Kintigh Station heat pipe unit, these results will be discussed. For the supply side, the carbon steel exhibited a high corrosion rate (60.8 mpy) at Location A. The supply side of the heat pipe unit is the evaporator end. Since the noncondensable gases are forced to the condenser end of a heat pipe, corrosion suffered at the evaporator end of a heat pipe is not affected by a gas block (noncondensable gases) in the condenser end of the heat pipe.

At Location B the mill scale on the carbon steel was largely intact. The Cor-Ten B® suffered little corrosion in both locations. The AL-6XN® showed no corrosion as the mill applied line identification was readable. In general, the corrosion on the supply side was much less severe than the return side corrosion.

The alloy 2205 heat pipe exhibited pitting corrosion underneath scale deposits. These pits were 0.0011" to 0.005" deep. This information is reported but it can be misleading. Pitting corrosion is a form of localized attack which can cause rapid perforation of metal sections. When pits are actively corroding, material removal in the pit is extremely rapid. It is generally accepted in the corrosion community that the rate of pitting attack is unpredictable. The pitting was preferential to the ferrite phase of the alloy 2205 and can be seen in figures 32 and 33. This indicates that sulfur compounds are the probable cause of the alloy 2205 pitting on the supply side as duplex stainless steels are generally resistant to corrosion by chlorides.

Several operational considerations of the heat pipes were investigated. The corrosion patterns on the AL-6XN® and the carbon steel heat pipes were suspected to be caused by operation of the heat pipes. Gas blockage in the heat pipe condenser end would allow the blocked area to operate at a colder temperature than the remainder of the heat pipe, thus, accelerating corrosion. A similar phenomena could occur in the evaporator would on start-up. The fill fluid would absorb heat and the upper section of the evaporator would heat up rapidly due to the absence of fill fluid. Therefore, the lower section would experience more corrosion on start-up. Since the problem is dewpoint corrosion, any sulfuric acid or ABS that condensed on the heat pipe would remain on the heat pipes. The gas and heat pipe temperatures would not necessarily evaporate the condensed acid so it would corrode the material until the acid was converted to corrosion products.

This information and analysis of fill fluid problems are reported in Appendix A.

The alloy 2205 heat pipe exhibited many different corrosion rates. These rates represent different conditions in the unit, for example, the ends of the heat pipes (Table 2 data) were in the tube sheet or through the tube sheet so the corrosive conditions were different for this area of the heat pipe. Also, the return side and the supply side conditions were different. On the return side, the corrosion varied about the diameter of the tube shown in Figures 19, 20, 21, and 22. The information for this area reported in Figure 25 is the area of maximum attack and the data reported in Figure 26 is an area of minimal attack.

It was noted that the corrosion was not uniform down the length of the test heat pipes or the actual heat pipe. This indicates a channeling of the gas flow in the unit. Perhaps the deposition of solids in Modules 2 and 3 altered the gas flow or for some reason, the mass flows were not uniform across the duct cross-section. Each heat pipe module should serve as a flow straightener so the nonuniform attack is difficult to explain.

When corrosion rates were evaluated for the alloy 2205 heat pipe, the original plan was to optically measure the thickness of the tube underneath the center mounting flange. In reality, it was found that the braze alloy underneath the fins had protected the original surface of the tube, this wall thickness was measured and used as the base thickness to calculate corrosion rates.

There is a tendency to statistically evaluate corrosion data by averaging. The problem with this approach is that there are not average corrosion rates in real systems. Maximum corrosion rates are the rates that must be considered, since, the maximum rate is the one that will remove the material and cause downtime in the system.

Cor-Ten B® is a registered trademark of the United States Steel Corporation.

AL-6XN® is a registered trademark of Allegheny Ludlum Steel Corporation.

REFERENCES

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2. McCoy, D. to Peter, J.; January 22, 1993. "Interim Report--HSTC Heat Pipe Operation". Photocopy.
3. McCoy, D. to Janik, G.; February 8, 1993. "Trip Report--HSTC Heat Pipe Inspections 1/25/93 and 1/26/93". Photocopy.
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6. McCoy, D. To Janik, G.; June 17, 1993. "Trip Report-HSTC Heat Pipe Inspections 5/17/93 and 5/18/93". Photocopy.
7. Fontana, M. G. & Greene, N. D.. *Corrosion Engineering*. New York:McGraw-Hill Book, 1967.

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HSTC Heat Pipe Exchanger

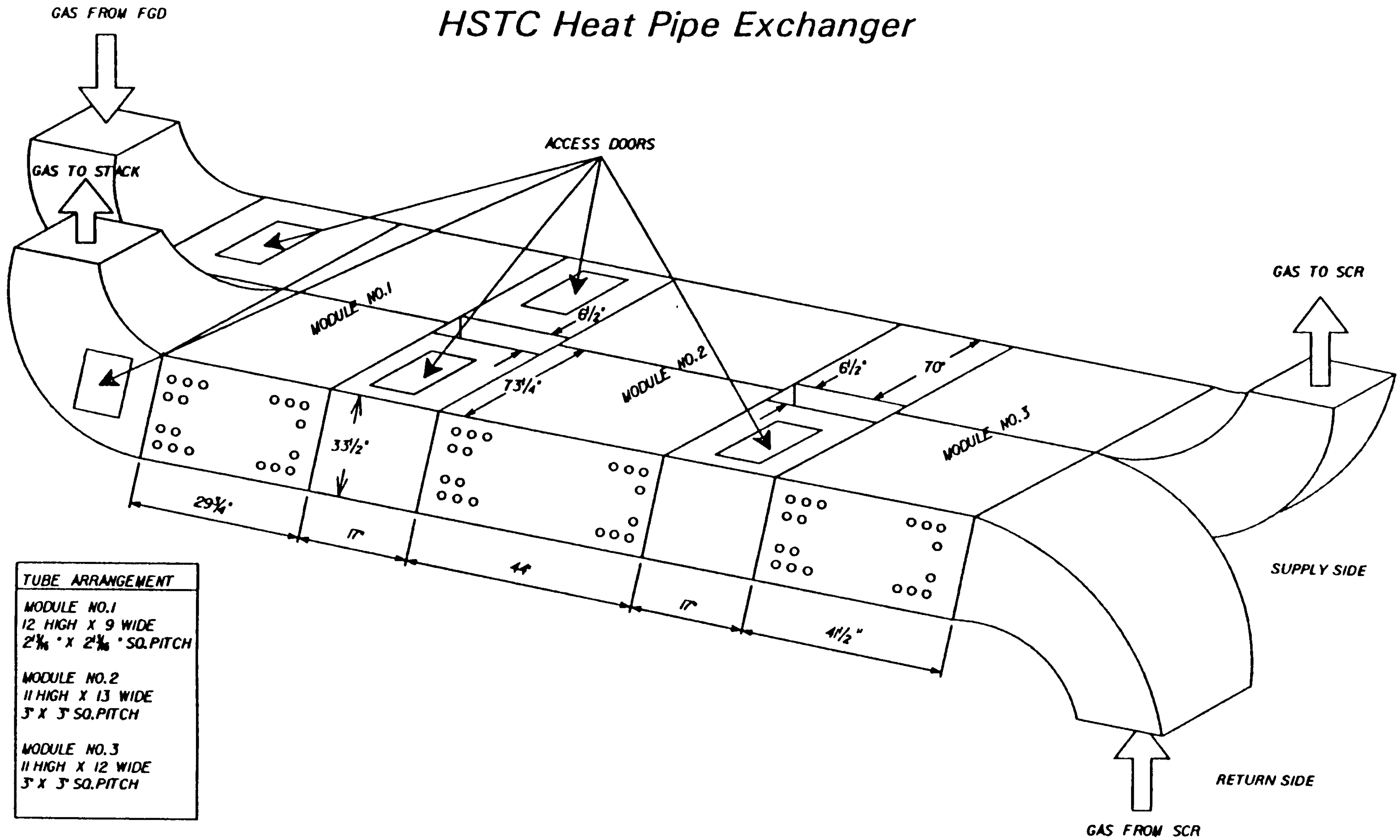
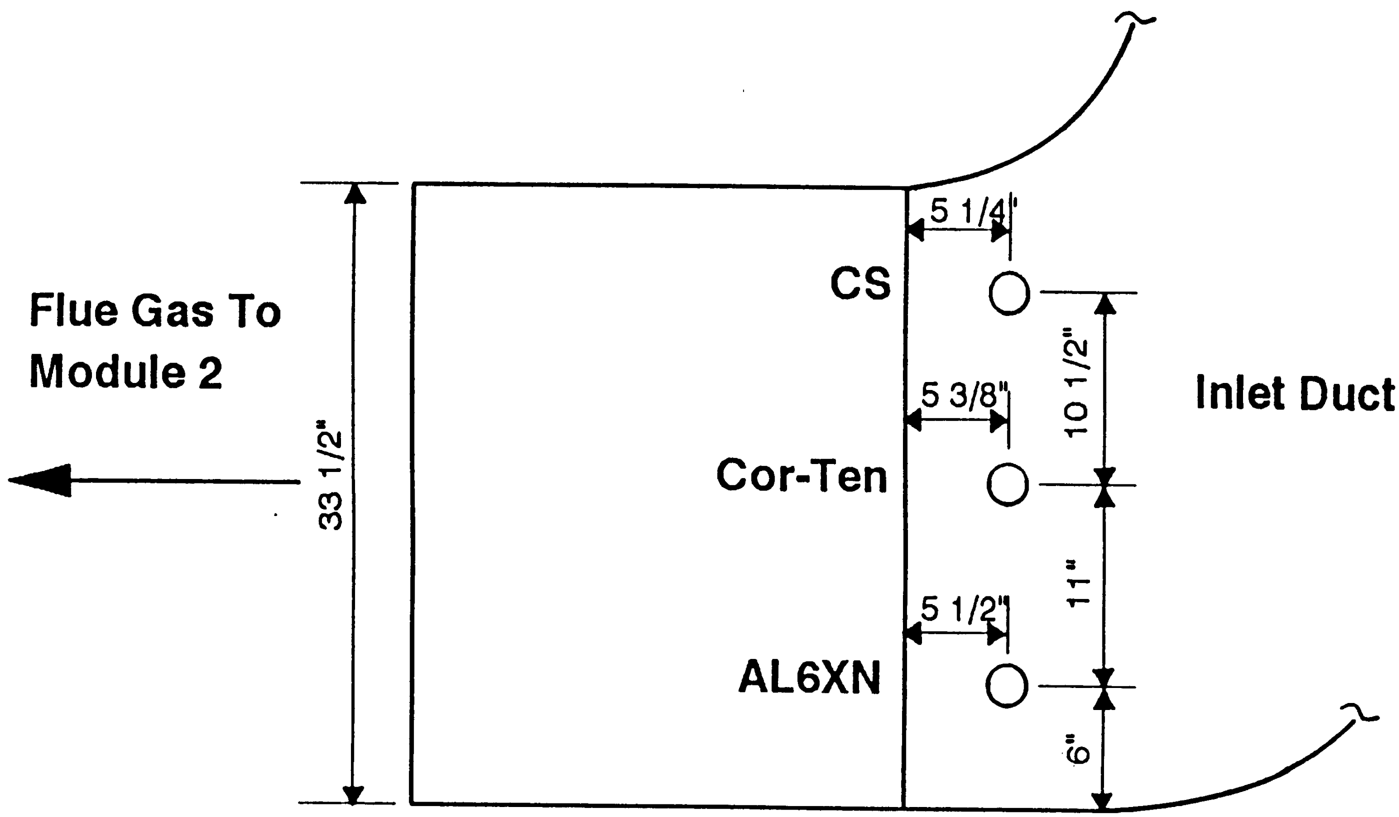


Figure 1

Figure 2

LOCATION OF ABB HEAT PIPES (POSITION A)

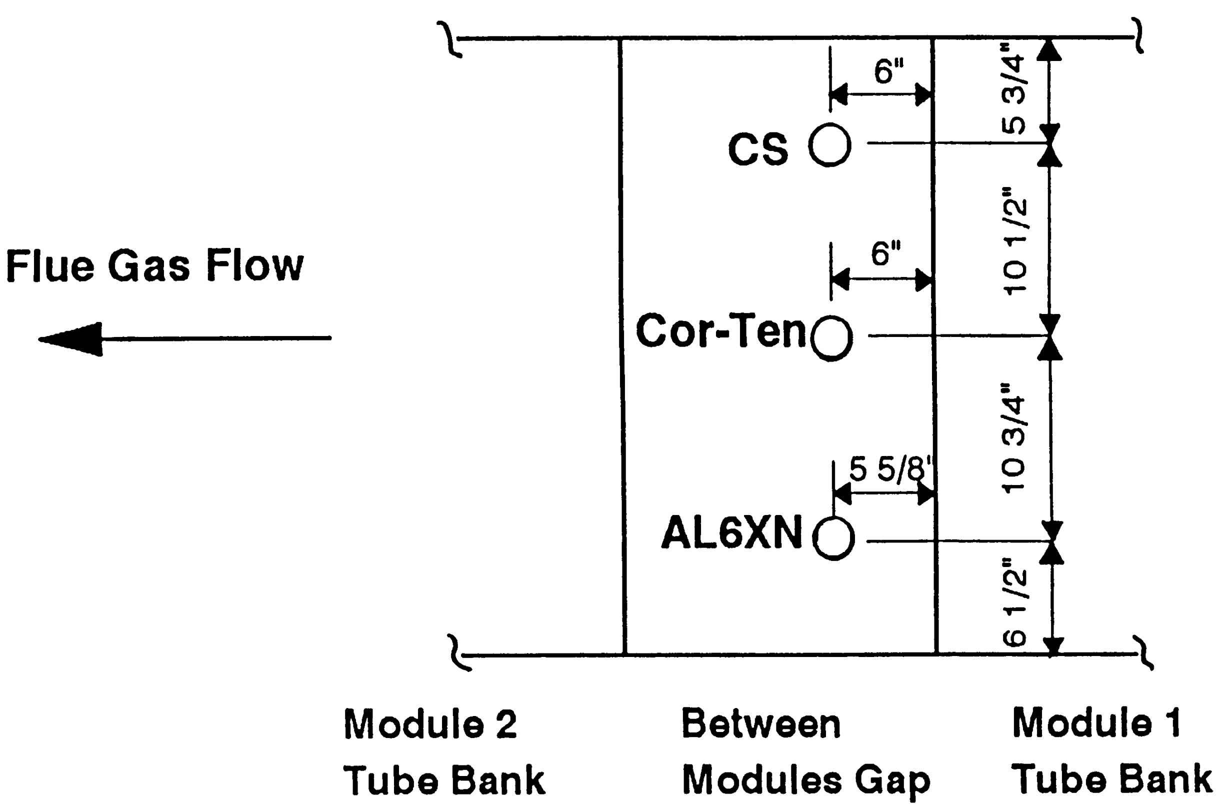


Module 1 Tube Bank

View From Supply Side Duct

Figure 3

LOCATION OF ABB HEAT PIPES (POSITION B)



View From Supply Side Duct

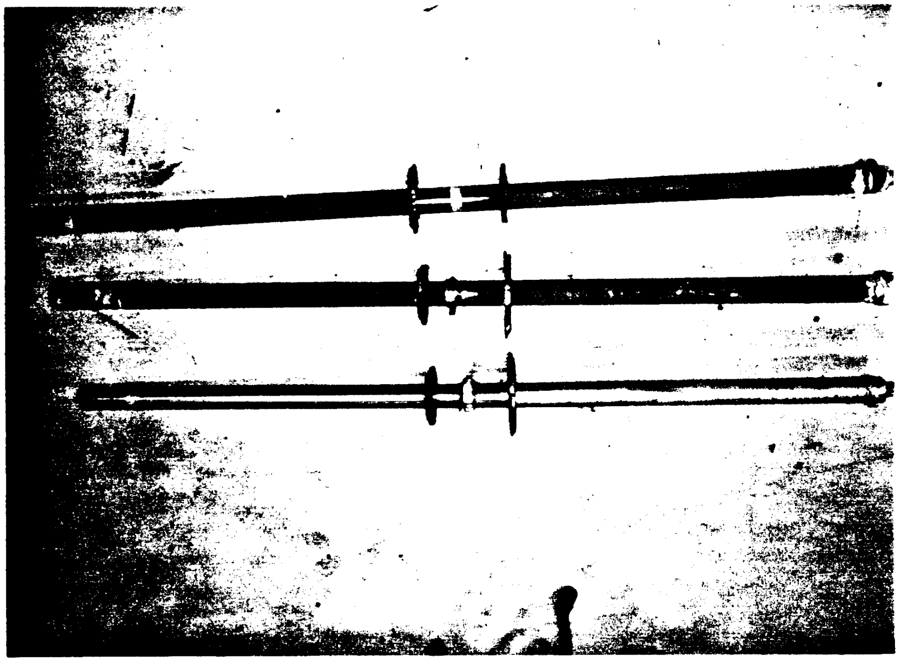


Figure 4

Showing all of the test heat pipes from Location A.

Carbon Steel	Top
Cor-Ten B®	Middle
AL-6XN®	Bottom

Magnification: 0.06X

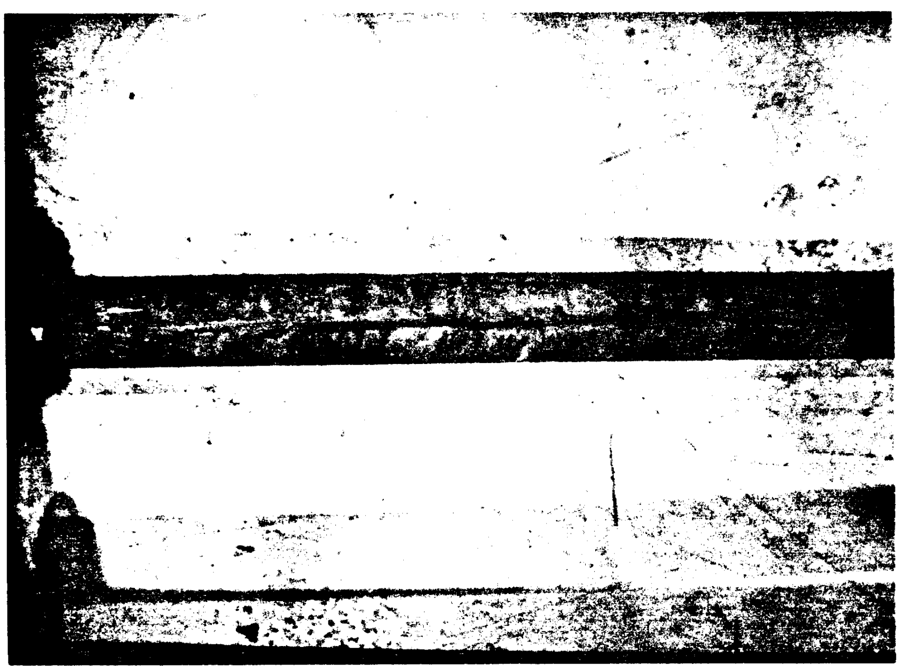


Figure 5

Showing the bottom of the carbon steel test pipe. NOTE: the "grooving" on the top portion of the heat pipe as shown in the photo.

Magnification: 0.24X

Figure 6

Showing a pencil tracing of the "grooving"
on a section of the carbon steel heat pipe
Location A, return side.

Full size

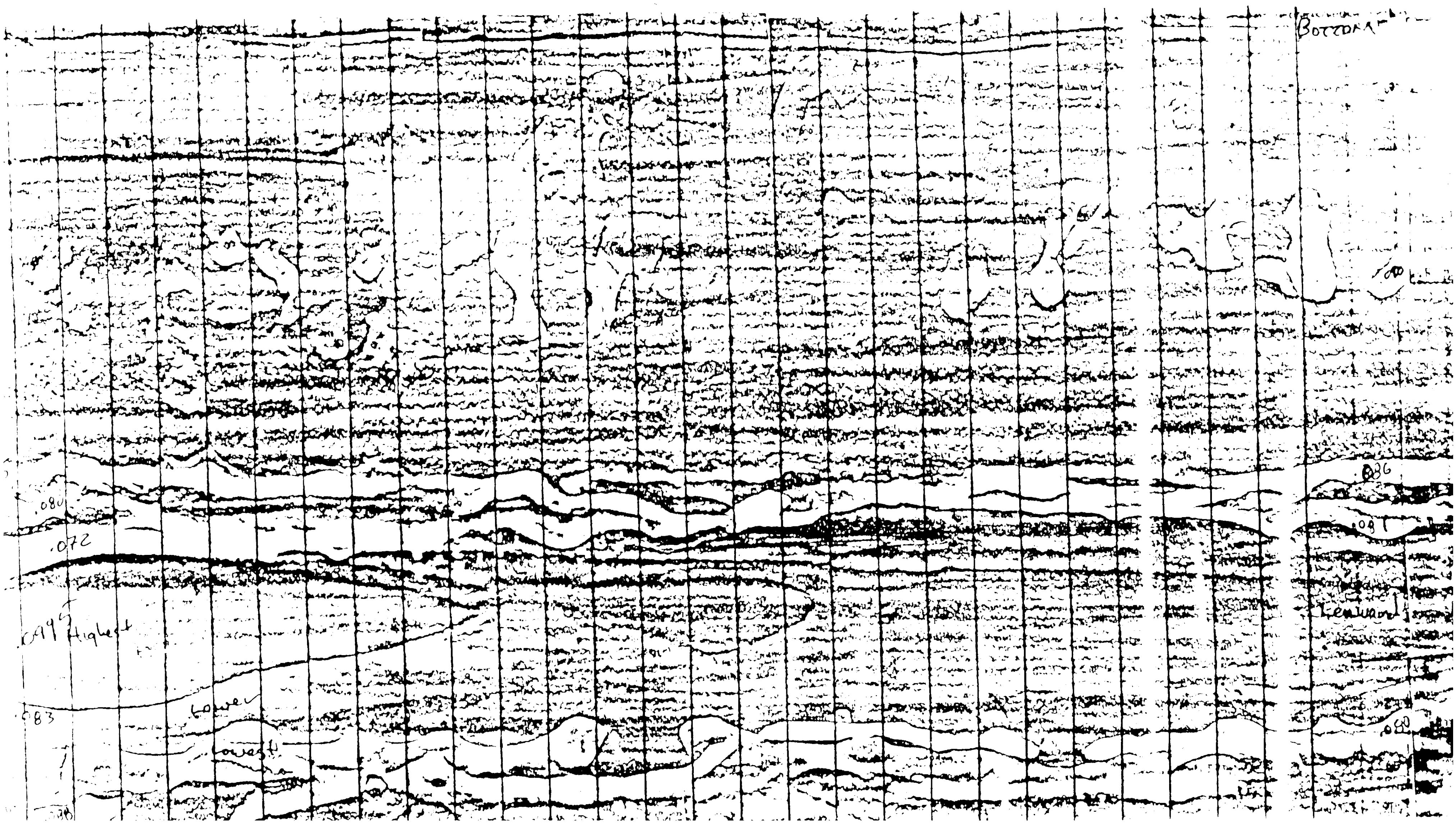


Figure 7

Showing the corrosion (pitting) of the AL-6XN® heat pipe, Location A, return side.

Magnification: 0.6X

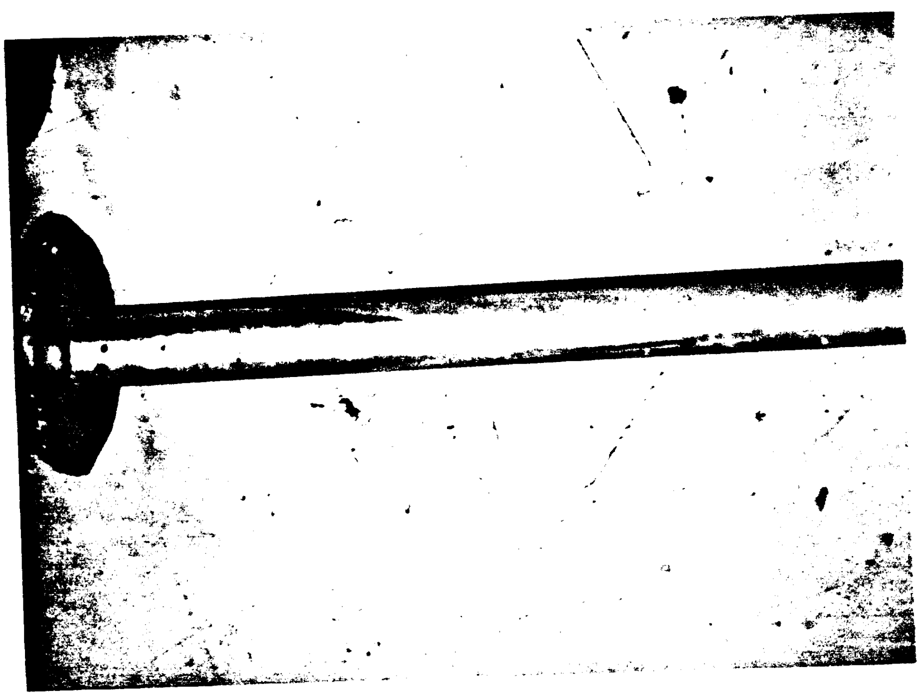


Figure 8

Showing the corrosion patterns on the AL-6XN®, Location A, return side.

Magnification: 0.22X

Figure 9

Showing the end of the carbon steel heat pipe. Location A, supply side.

Magnification: 0.25X

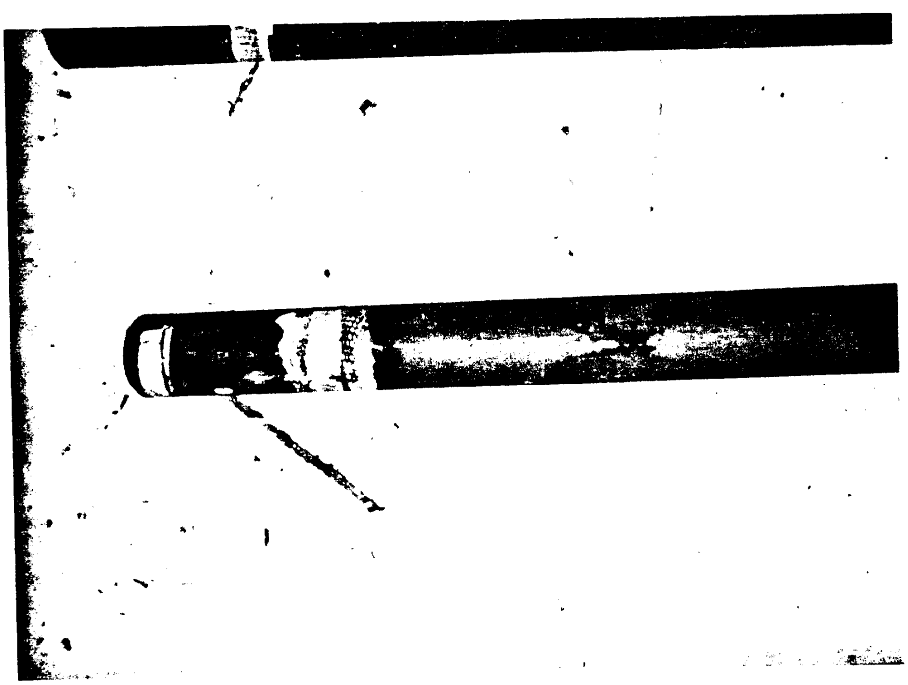


Figure 10

Showing the end of the Cor-Ten B® heat pipe. Location A, supply side.

Magnification: 0.22X

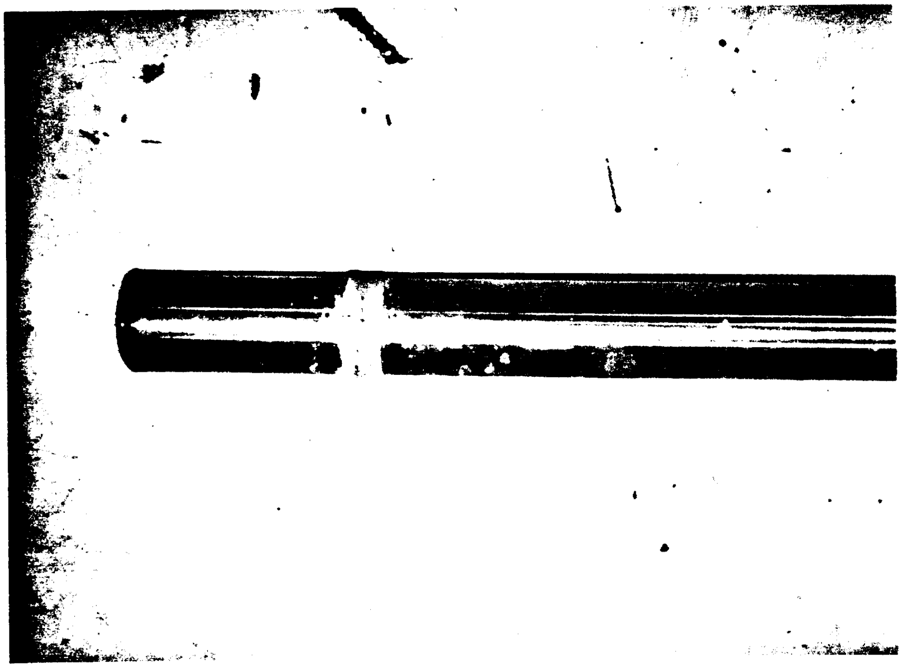


Figure 11

Showing the end of the AL-6XN®. Location A, supply side.

Magnification: 0.26X

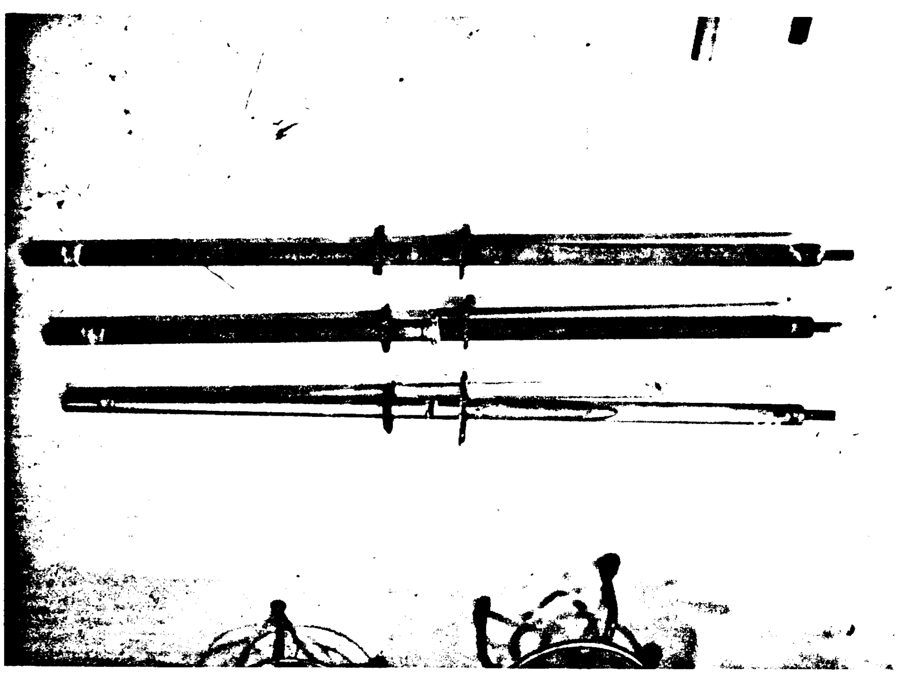


Figure 12

Showing the three heat pipes from Location B.

Carbon steel	Top
Cor-Ten B®	Middle
AL-6XN®	Bottom

Magnification: 0.06X

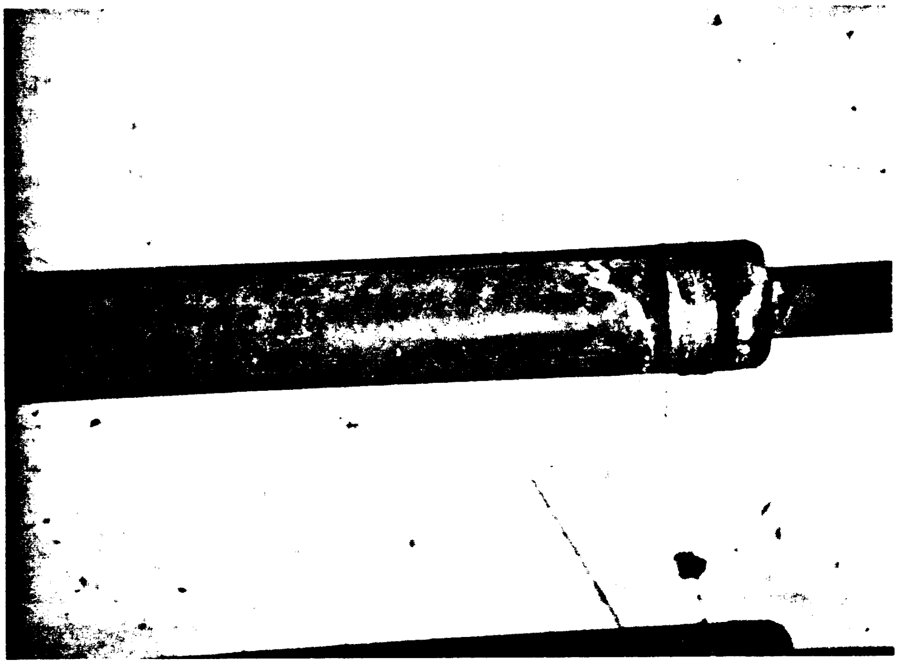


Figure 13

Showing the end of the carbon steel heat pipe. Location B, return side.

Magnification: 0.31X

Figure 14

Showing the end of the Cor-Ten B® heat pipe. Location B, return side.

Magnification: 0.36X

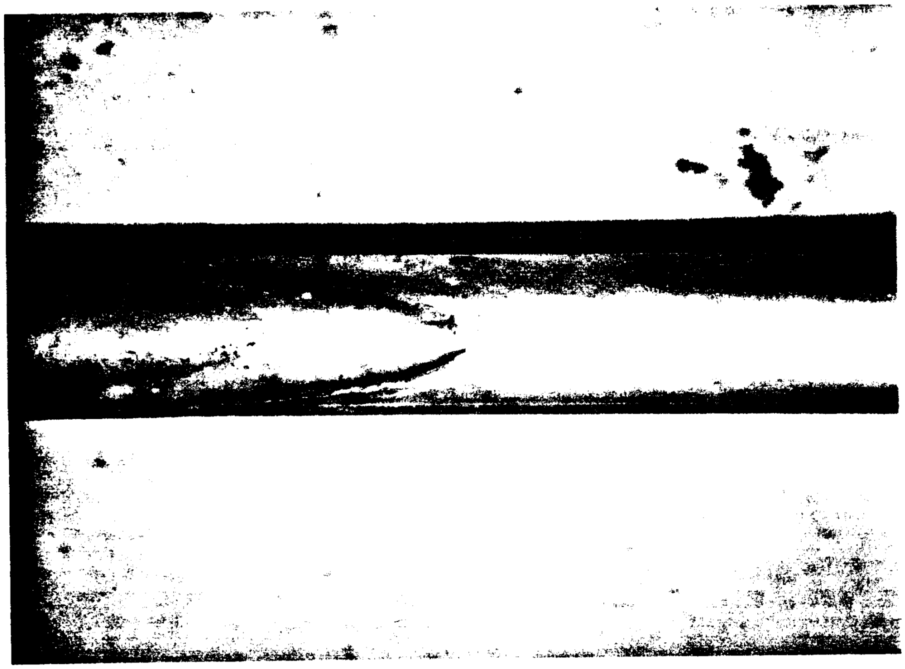


Figure 15

Showing the corrosion stain on the AL-6XN® heat pipe. Location B, return side.

Magnification: 0.43X

Figure 16

Showing the end of the carbon steel heat pipe. Location B, supply side.

Magnification: 0.29X

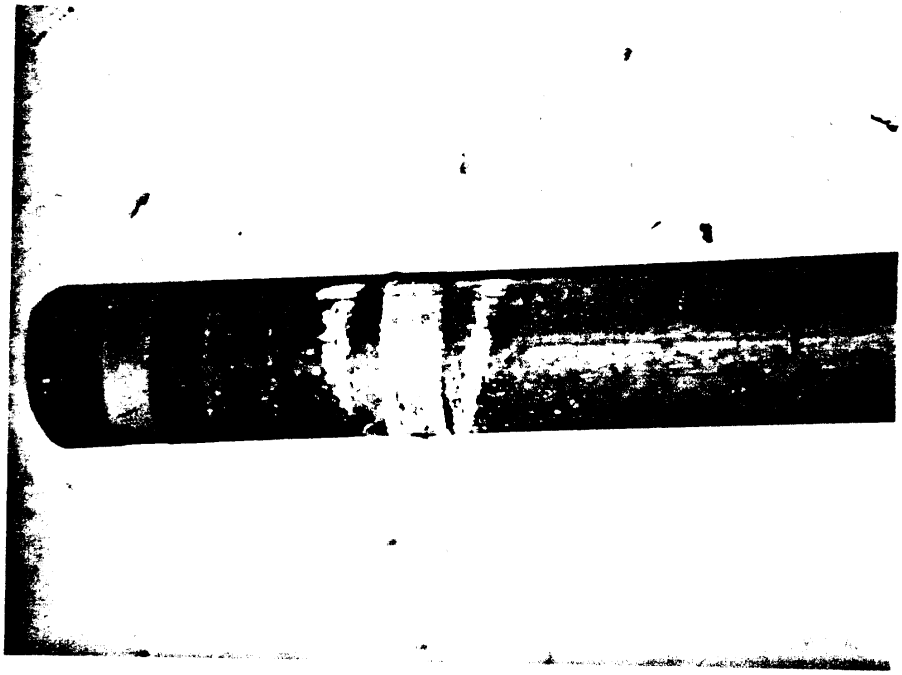


Figure 17

Showing the end of the Cor-Ten B® heat pipe. Location B, supply side.

Magnification: 0.42X

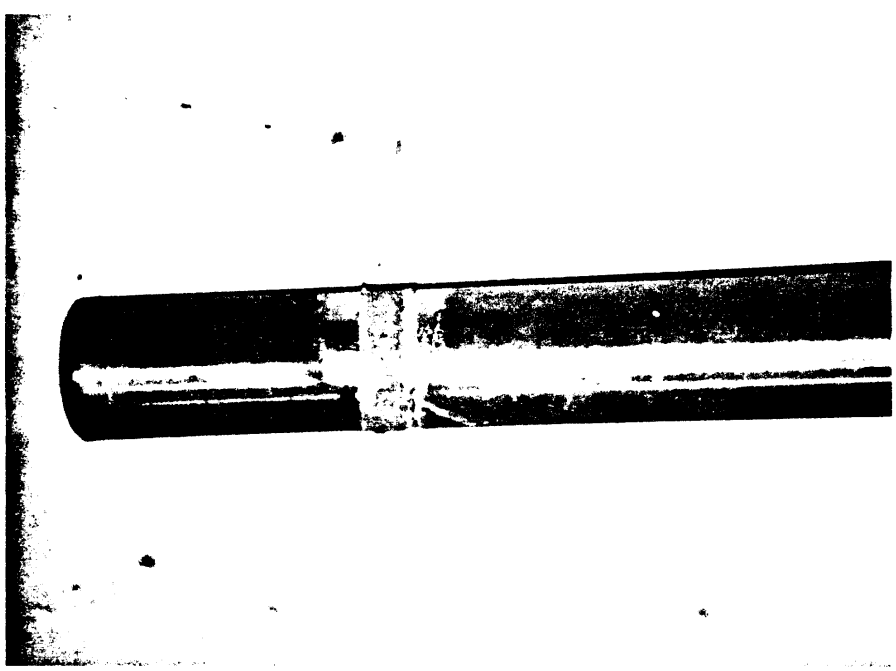


Figure 18

Showing the end of the AL-6XN® heat pipe. NOTE the mill's line marking. Location B, supply side.

Magnification: 0.38X

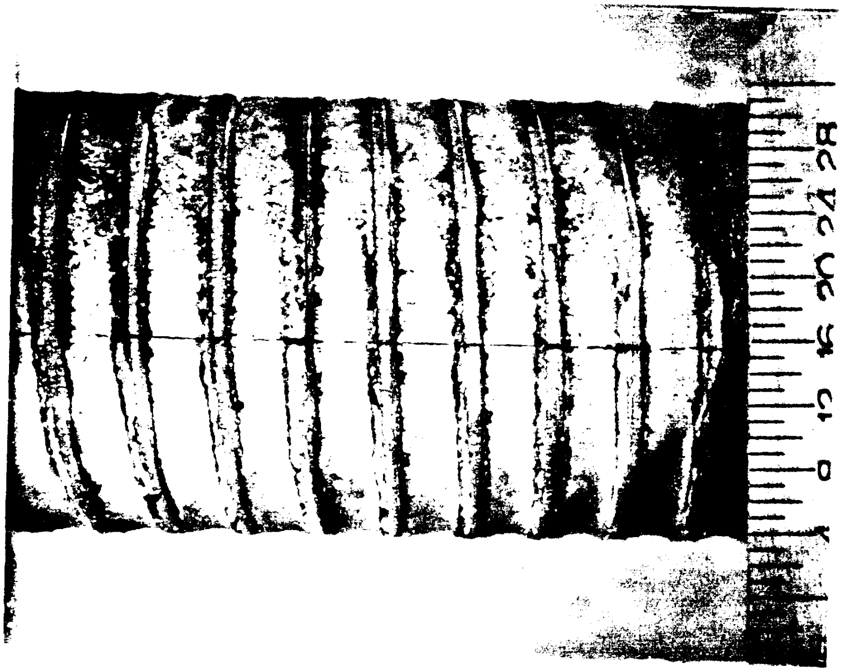


Figure 19

Showing the corrosion attack on the bottom of the alloy 2205 tube. Return side.

Magnification: 2.8X

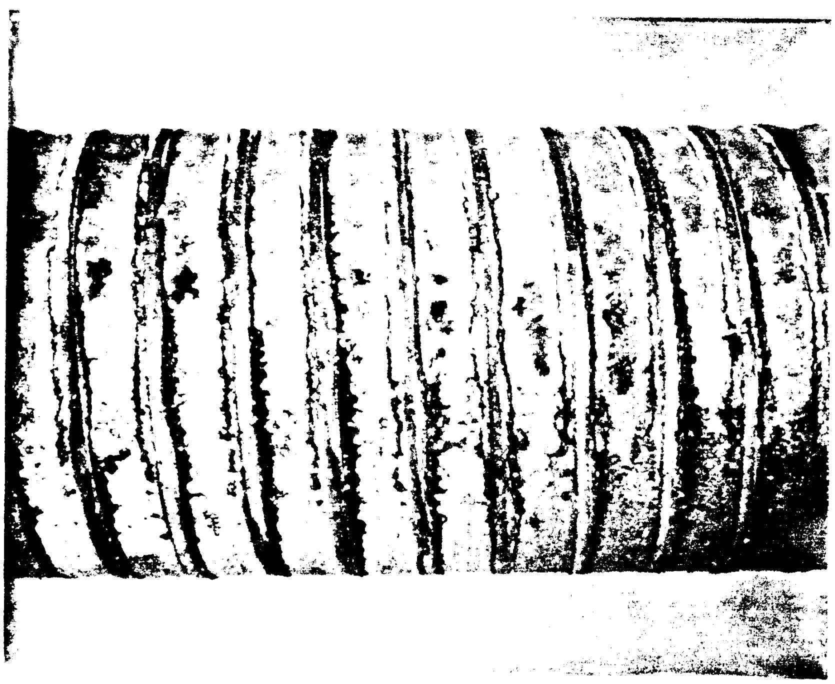


Figure 20

Showing the corrosion attack on the leading edge of alloy 2205 tube. Return side.

Magnification: 2.8X

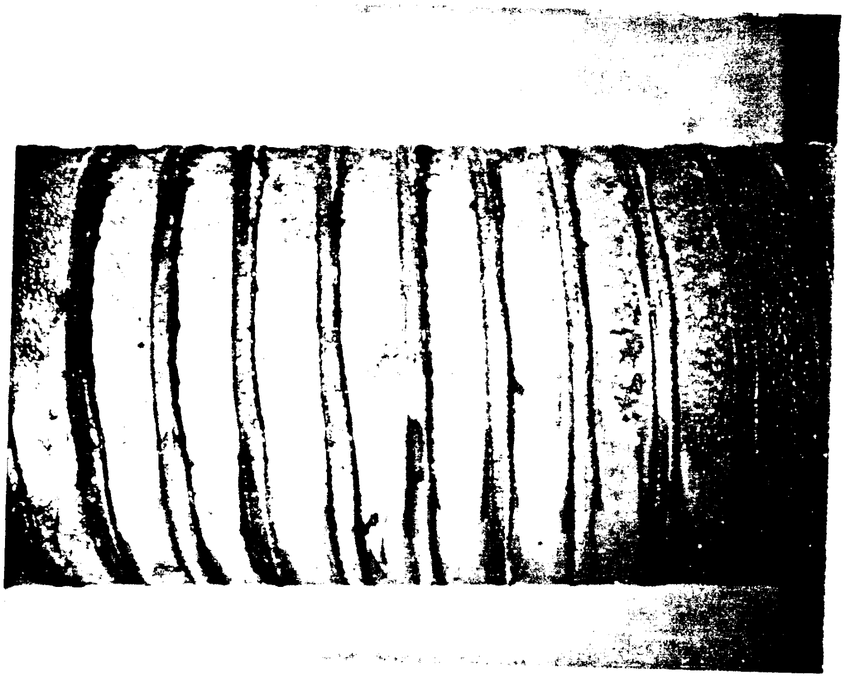


Figure 21

Showing the corrosion attack on the bottom of the alloy 2205 tube. Return side.

Magnification: 2.8X

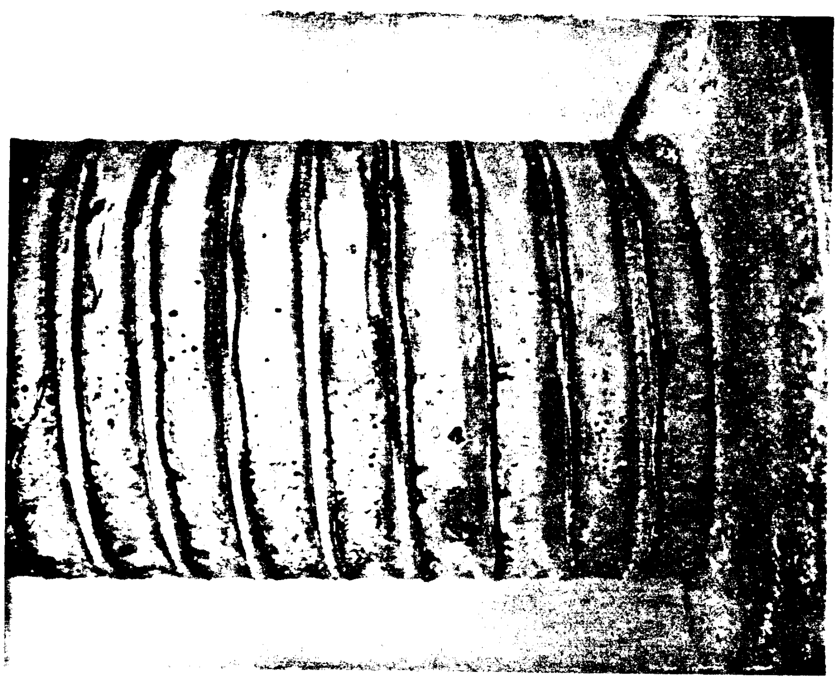


Figure 22

Showing the corrosion attack on the trailing edge of the alloy 2205 tube. Return side.

Magnification: 2.8X

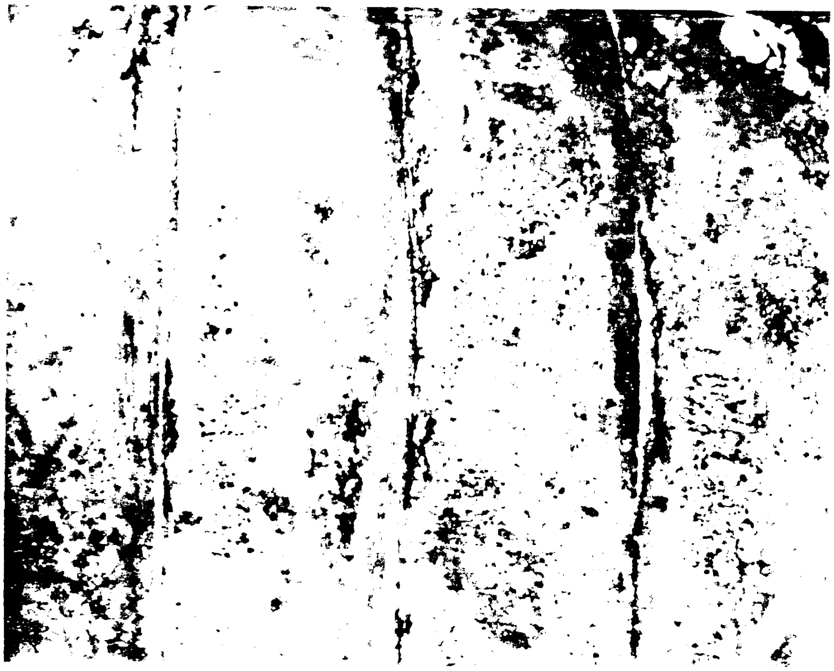


Figure 23

Showing the pitting corrosion on the alloy 2205 tube. Supply side.

Magnification: 5.4X

Figure 24

Showing the locations of the metallographic samples taken from the alloy 2205 tube. Mount 1797 was examined but was not significantly different from mount 1798.

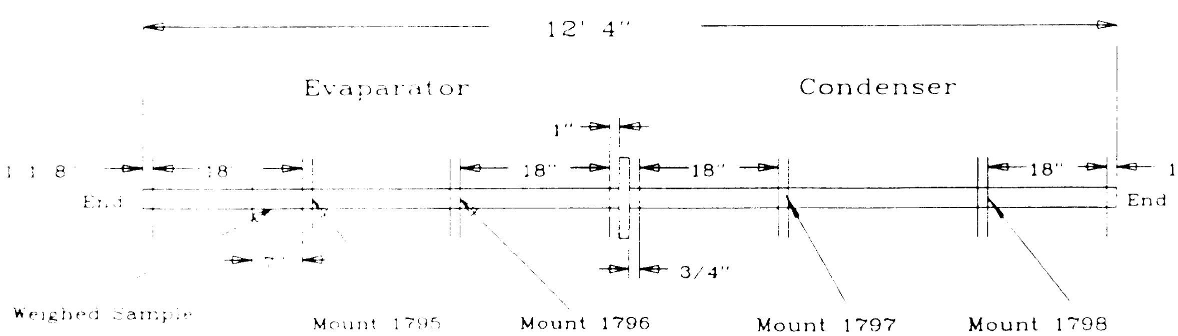


Figure 25

Thickness and Corrosion Results - Return Side - Leading Edge of Tube Mount #1795
(Alloy 2205 Tube/AISI 409 Fin Materials)

All thickness measurements are in inches

Tube - Under Fin

Covered	Uncovered
0.0767	0.0762
0.0766	0.0738
0.0768	

Corrosion Rate, mpy

Uncovered
0.4
2.5

Tube- Exposed

	1/4	midpt	3/4
A	0.0748	0.0706	0.0716
B	0.0742	0.0711	0.0756

Corrosion Rate, mpy

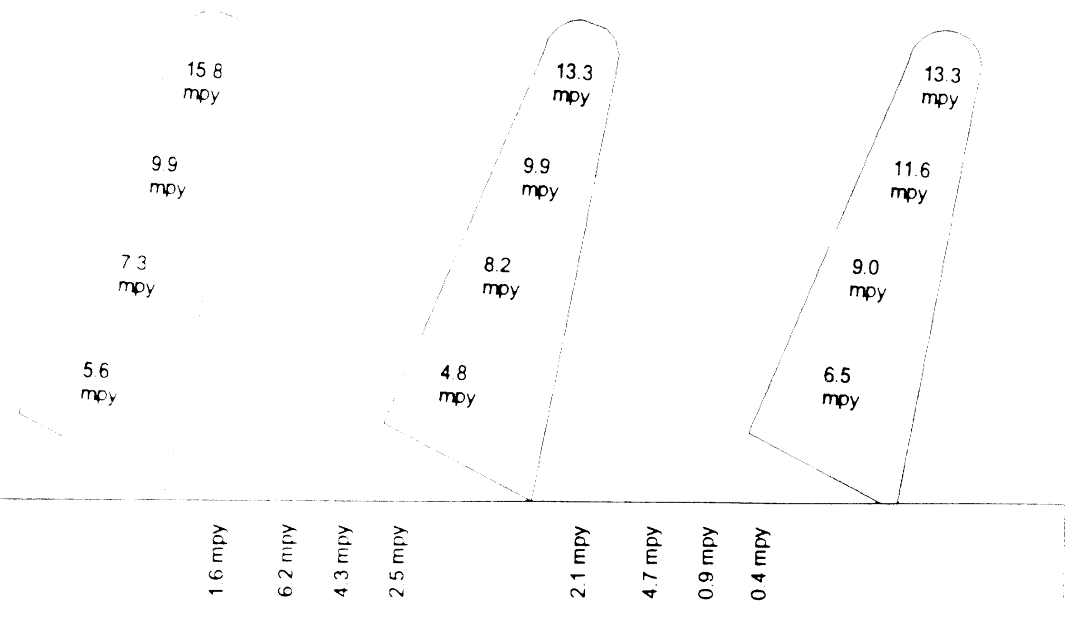
1/4	midpt	3/4
1.6	5.2	4.3
2.1	4.7	0.9

Fin

	Base	1/4	midpt	3/4	Tip
1	0.044	0.038	0.035	0.032	0.03
2	0.046	0.040	0.036	0.034	0.03
3	0.047	0.039	0.037	0.034	0.027

Corrosion Rate, mpy

1/4	midpt	3/4	Tip
6.5	9.0	11.6	13.3
4.8	8.2	9.9	13.3
5.6	7.3	9.9	15.8



Showing the corrosion rates on a graphical representation on the examined section

File Kintigh3 Sam

Figure 26

Thickness and Corrosion Results - Return Side - Trailing Edge of Tube Mount #1796
(Alloy 2205 Tube/AISI 409 Fin Materials)

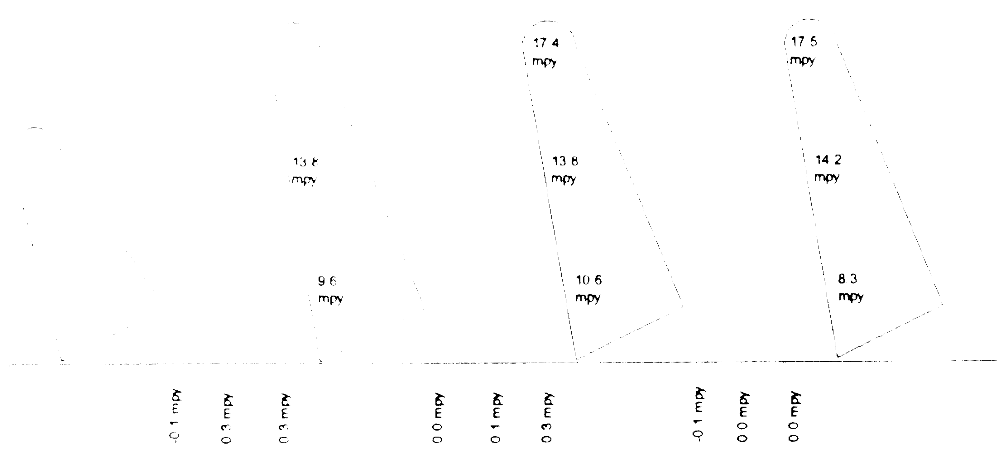
All thickness measurements are in inches

Tube - Under Fin

Covered	Uncovered	
0.0792	0.0788	
0.0783	0.0784	Average
0.0786	0.0788	0.0787
0.0788		

	Tube- Exposed			**Corrosion Rate, mpy**		
	1/4	midpt	3/4	1/4	midpt	3/4
A	0.0788	0.0784	0.0784	-0.1	0.3	0.3
B	0.0787	0.0786	0.0784	0.0	0.1	0.3
C	0.0788	0.0787	0.0787	-0.1	0.0	0.0

	Fin				**Corrosion Rate, mpy**		
	Base	1/3	2/3	Tip	1/3	2/3	Tip
1	0.0512	0.0396	0.0347		9.6	13.8	
2	0.0505	0.0384	0.0346	0.0304	10.6	13.8	17.4
3	0.0511	0.0411	0.0342	0.0303	8.3	14.2	17.5



Showing the corrosion rates on a graphical representation of the examined section.

File: Kintigh4.SAM

Figure 27

Showing the cracking in the bottom of the pits in the AL-6XN®. Location A, return side.

Magnification: 200X

Unetched

Figure 28

Showing the details of the AL-6XN® cracking.

Magnification: 200X

Etchant: Mixed acids followed by electrolytic 10% Oxalic Acid

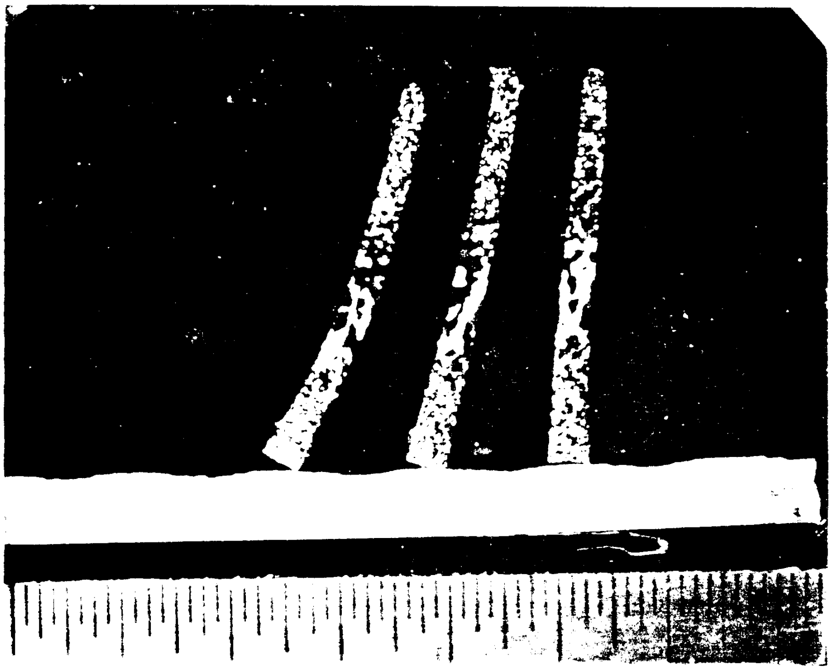


Figure 29

Showing the preferential corrosion attack of the leading edge of the alloy 2205 tube.

Magnification: 4.8X

Etchants: Glyceregia followed by Electrolytic 10N KOH

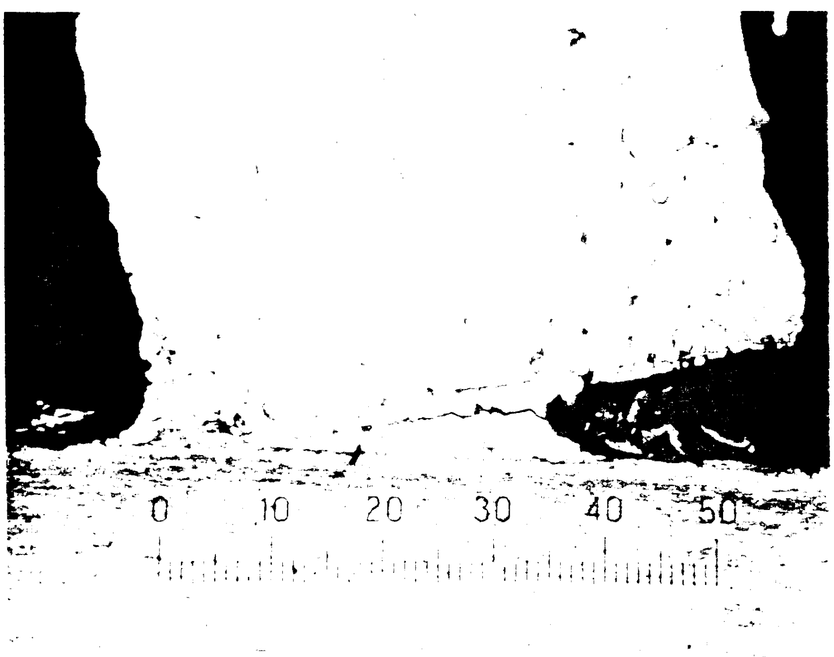


Figure 30

Showing the details of an AISI 409 fin to alloy 2205 tube braze joint.

Magnification: 75X

Etchants: Glyceregia followed by Electrolytic 10N KOH

Figure 31

Showing a group of pits in alloy 2205

Magnification: 100X

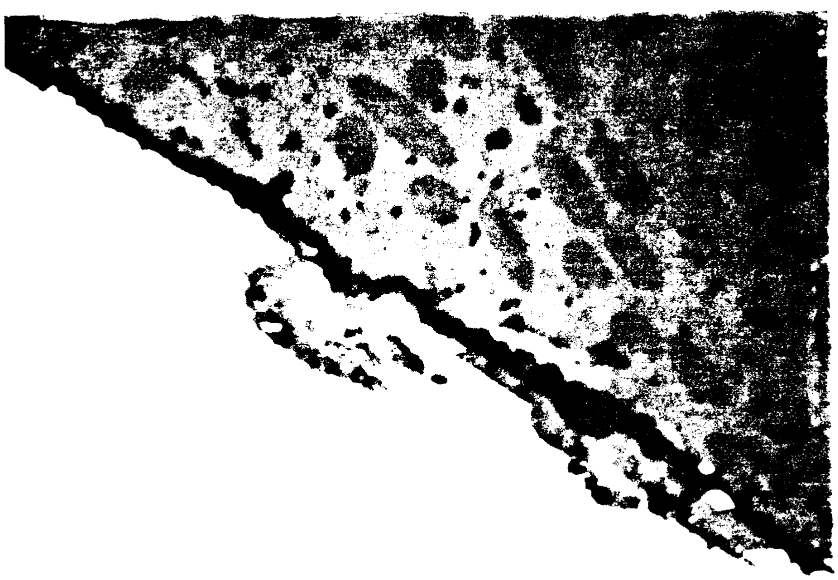


Figure 32

Showing one of the pits in Figure 31 at higher magnification. Note the corrosion product "fingers" penetrating into the material.

Magnification: 400X

Figure 33

Showing a large pit in the alloy 2205. The light phase is austenite and the dark phase is ferrite. This pit does not exhibit the prefferential attack as does Figure 32.

Magnification: 400X

Etchants: Glyceregia followed
by Electrolytic
10N KOH

TABLE 1

CORROSION RATES FOR KINTIGH STATION EXPERIMENTAL HEAT PIPES

Based on 3310 hours of operation

20-Dec-93

LOCATION KEY

#1 Adiabatic section
#2 Evaporator, 12" from center duct Return Side
#3 Evaporator, 24" from center duct Return Side
#4 Near Evaporator end Return Side
#5 Condenser, 18" from center duct Supply Side
#6 Near Condenser end Supply Side

			WALL THICKNESS, INCHES				CORROSION RATE, MPY				
	Location	Section	TOP	SIDE	BOTTOM	SIDE	TOP	SIDE	BOTTOM	SIDE	GREATEST
Carbon Steel Toluene	B	CT1	0.104	0.102	0.101	0.101					
	B	CT2	0.101	0.102	0.1	0.103	7.9	0	2.6	-5.3	
	B	CT3	0.102	0.101	0.101	0.102	5.3	2.6	0	-2.6	
	B	CT4	0.103	0.102	0.099	0.101	2.6	0	5.3	0	7.9
Carbon Steel Freon	A	CF1	0.098	0.102	0.102	0.103					
	A	CF2	0.099	0.102	0.099	0.096	-2.6	0	7.9	18.5	
	A	CF3	0.095	0.091	0.098	0.099	7.9	29.1	10.6	10.6	
	A	CF4	0.093	0.0975	0.1	0.086	13.2	11.9	5.3	45	45
	A	CF5	0.099	0.101	0.079	0.101	-2.6	2.6	60.8	5.3	
	A	CF6	0.097	0.101	0.1	0.101	2.6	2.6	5.3	5.3	60.8
		MISC	0.085	0.083	0.086	0.081	43	48.3	40.3	53.6	
		FIGURE 6	0.08	0.072	0.088	0.09	56.2	77.4	35.1	29.8	
			0.086	0.085	0.0995	0.08	40.3	43	4.6	56.2	77.4
Cor-Ten Freon	A	AF1	0.257	0.255	0.252	0.252					
	A	AF2	0.246	0.247	0.246	0.243	29.1	21.2	15.9	23.8	
	A	AF3	0.246	0.247	0.246	0.246	29.1	21.2	15.9	15.9	
	A	AF4	0.241	0.253	0.252	0.246	42.3	5.3	0	15.9	42.3
AL-6XN Toluene	B	ST1	0.06	0.061	0.061	0.059					
	B	ST2	0.061	0.062	0.059	0.061	-2.6	-2.6	5.3	-5.3	
	B	ST3	0.059	0.06	0.059	0.059	2.6	2.6	5.3	0	
	B	ST4	0.06	0.06	0.06	0.06	0	2.6	2.6	-2.6	5.3
AL-6XN Freon	A	SF1	0.061	0.06	0.061	0.059					
	A	SF2	0.06	0.057	0.06	0.055	2.6	7.9	2.6	10.6	
	A	SF3	0.061	0.059	0.06	0.059	0	2.6	2.6	0	
	A	SF4	0.06	0.059	0.06	0.059	2.6	2.6	2.6	0	10.6

Table 2

Thickness and Corrosion Results

Alloy 2205 Heat Pipe

All thickness measurements are in inches

1. **Base Thickness - Under Center Collar**

0.0774	0.0771	0.0771	0.0782
0.0769	0.0772	0.0780	

Average 0.0774

2. **Thickness Supply Side of the Unfinned End** / **Corrosion Rate, mpy** / **Greatest**

0.057	0.0685	0.063	17.3	7.5	12.2	18.1
0.068	0.056		8.0	18.1		

3. **Thickness Return Side of Unfinned End** / **Corrosion Rate, mpy**

0.067	0.07	0.071	0.071	8.8	6.3	5.4	5.4	9.7
0.071	0.07	0.066	0.068	5.4	6.3	9.7	8.0	

APPENDIX A

Appendix is not included since information is confidential to ABB API.

MILLIKEN CLEAN COAL TECHNOLOGY DEMONSTRATION PROJECT

MILLIKEN UNIT 2 ESP AND SLIPSTREAM HEAT PIPE CORROSION TESTS
July 15, 1993 to May 21, 1994
Final Report

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LIST OF ABBREVIATIONS

Amp	Ampere
Avg	Average
CCT-IV	Clean Coal Technology IV
CS	Carbon Steel
ECN	Electro Chemical Noise
ESP	Electrostatic Precipitator
g	Gram
Mils	0.001 inches
MW	Megawatt
ppmv	Parts Per Million by Volume
SCR	Selective Catalytic Reduction
SDEV	Standard Deviation
SS	Stainless Steel
TC	Thermocouple
NYSEG	New York State Electric & Gas
OD	Outside Diameter
dia	Diameter
R	Overall Corrosion Rate (Equation 1)
RH	Relative Humidity

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ABSTRACT

Corrosion monitoring tests were conducted at the Milliken Station to determine the performance of SA-178A carbon steel (CS), Cor-Ten™ A, and 2205 duplex stainless steel in the flue gas environment that will exist at the outlet of the new Unit 2 heat pipe air heater. Two types of probes, manual air-cooled and real-time CAPCIS electronic probes, were used to measure corrosion rates. Corrosion rates were measured in flue gas environments with and without fly ash and with fly ash and ammonia present. The 2205 SS was eliminated from the test program because of deep, rapid pitting. The test results showed that Cor-Ten A exhibited a low corrosion rate, typically about 2 mils/yr, and was a suitable material of construction for the heat pipe cold-end outlet. The test results also indicate that SA-178A CS is a suitable material for the ductwork downstream of the heat pipe. The electronic corrosion probe results showed that high corrosion rates can occur during shutdown periods, particularly for carbon steel. The off-line corrosion is likely due to wall sweating when ambient relative humidity is high. Failure to adequately sootblow fly ash deposits appears to result in severe localized metal attack on Con-Ten A.

SUMMARY

Two heat pipe air heaters were installed on the Milliken Station Unit 2 boiler as part of the thermal performance improvement modifications for the CCT-IV test program. Prior to installing the new heat pipes, tests were conducted at the Milliken Station to determine the corrosion rates of candidate materials of construction for the cold-ends of the air heaters. Two types of corrosion probes were used for the tests; simple air-cooled probes and electronic CAPCIS probes. The air-cooled probes required manual measurement of diameters for estimation of corrosion rates. The CAPCIS probes provided real-time corrosion rates that changed with operating conditions.

The simple air-cooled probes were made of Cor-Ten A™ (two probes) and 2205 stainless steel (SS). These probes were placed in the ducts between the 2A and 2B Ljungstrom air heaters and the 2A and 2B ESPs for long term exposure to a flue gas/fly ash environment. The CAPCIS probes were made of SA-178A carbon steel (CS) (probe 1) and Cor-Ten A (probe 2). The probes were used in two locations; the outlet of the 2A ESP (SA-178A probe only), in a flue gas without fly ash environment, and the outlet of the slipstream heat pipe (both probes), in a fly ash and ammonia containing flue gas environment. The ammonia was from an upstream NO_x removal process.

The test results indicate that both SA-178A CS and Cor-Ten A are suitable materials of construction for the cold-end of the heat pipe while 2205 SS is not suitable. During short-term testing, 2205 SS pitted severely when exposed to a flue gas environment. The test results indicate that SA-178A is suitable for the ductwork downstream of the heat pipe.

The test results demonstrated that high corrosion rates could occur for carbon steel during shutdown periods when humid ambient air enters the ductwork. Although not measured by the real-time probe, rapid blistering of the manual probe indicates humid air conditions also may cause increased corrosion of Cor-Ten. Controlling ductwork humidity during a shutdown is one method of limiting or eliminating this form of corrosion.

RESULTS

Results for the corrosion test program are:

Air-Cooled Corrosion Probes

- Flue gas environment corrosion rates are typically less than 3 mils/yr for the Cor-Ten A probes regardless of whether the probes are operated at average target temperatures of 172°F, 192°F or 202°F.

- The corrosion rates for 2205 SS operated at 170°F are less than 5 mils/yr. However, extensive surface pitting occurs where fly ash is deposited. Because pitting corrosion causes rapid penetration of tube walls with little metal loss, the test results demonstrate that 2205 SS is not suitable for use in the cold-end of the full-scale heat pipe air heater.

- Corrosion rates based on probe diameter measurements do not indicate a general trend with distance from the cold end to the hot end of the probe. However, one Cor-Ten A probe did visually appear more corroded over the bottom 4" (the coldest portion of the probe) than over the top 12".

- There is evidence that severe metal attack of Cor-Ten A may occur under fly ash deposits which are left in place for prolonged periods. The probable cause is continued acid deposition on the probes when the metal surface temperatures are below the sulfuric acid dew point. This eventually depletes any components in the fly ash which neutralize the acid. Adequate sootblowing to remove fly ash deposits before they become acid saturated should minimize this form of corrosion.

CAPCIS Probes

- At the ESP outlet, the CAPCIS corrosion rates for SA-178A are low and do not differ significantly for the two metal surface temperatures tested. Corrosion rates are 1.9 mils/yr at 168°F and 2.3 mils/yr at 231°F. The low corrosion rates were confirmed by manual measurements of the sensing elements. This showed that the measured electronic corrosion rate was below the potential error associated with the precision or resolution of caliper measurements (i.e., 2.7 mils/yr and 2.9 mils/yr for the 168°F and 231°F tests, respectively). These results indicate that carbon steel should be a suitable material for the duct work downstream of the ESP.

- At the slipstream heat pipe outlet, the CAPCIS probes were exposed to a flue gas environment containing both fly ash and ammonia from a pilot NO_x removal process. Measured corrosion rates based on sensing element diameter changes are low for both SA-178A and Cor-Ten A materials. Overall rates based on manual measurements for SA-178A are between 2.9 to 3.5 mils/yr at 176°F and for Cor-Ten A are between 1.7 to 1.9 mils/yr at 174°F. These results indicate that Cor-Ten A is the most corrosion resistant of the two materials. Either material would be suitable for cold-end heat pipe construction. Based on a corrosion rate of 3.5 mils/yr for SA-178A and 1.9 mils/yr for Cor-Ten A, minimum tube wall thicknesses are 0.085" and 0.053", respectively, assuming 20-year life and the need for 15 mils minimum metal thickness for pressure containment.

- At the slipstream heat pipe outlet, the CAPCIS corrosion rate for SA-178A averaged 3.5 mils/yr. This corrosion rate, based on the electrical response of the CAPCIS probe, was confirmed by manual diameter measurements of the sensing elements.

- Corrosion rates based on manual measurements of probe diameters indicated that the corrosion rate coefficient previously developed for Cor-Ten B over predicts by about seven times the corrosion rate for Cor-Ten A.

- Fly ash in the flue gas appears to provide some protection against SO_3 and/or ammonium bisulfate, $(NH_4)HSO_4$, attack. Ammonia slip during the Milliken heat pipe tests averaged about 2.5 ppmv. Corrosion rates for both SA-178A and Cor-Ten A were generally lower than experienced at the Kintigh Station for SA-178A and Cor-Ten B in a fly ash free flue gas with 2 ppmv ammonia slip. At Kintigh, corrosion rates for SA-178A did not drop to 2-4 mils/yr until temperatures were greater than about 195°F and remained high (>10 mils/yr) for Cor-Ten B even at the highest test temperatures (up to 230°F).

CONCLUSIONS

Based on the corrosion test results the following conclusions are made:

- Cor-Ten A appears to be an acceptable construction material for the heat pipes in the cold-end module of the Unit 2 air heater.

- Purging the ductwork with dry or heated air may reduce corrosion during downtime periods by eliminating the metal sweating which allows corrosion to occur.

- Providing cold-end sootblowing so that tube surface deposits are routinely removed in a timely fashion will likely prevent deposits from becoming acid soaked and should minimize corrosion rates.

- Visual inspections of the air-cooled corrosion probes indicate increased corrosion for metal temperatures below 170°F. To minimize corrosion, the heat pipe should be operated to maintain tube metal skin temperatures at or above 170°F.

- When using the CAPCIS probes to monitor corrosion rates, a corrosion rate coefficient of 4.39×10^8 mils/(yr-amp) should be used for SA-178A and 6.44×10^7 mils/(yr-amp) for Cor-Ten A.

INTRODUCTION

General

As part of the Clean Coal Technology IV (CCT-IV) program, a full-scale heat pipe air heater was installed at the Milliken Station to improve system thermal efficiency. A corrosion study was conducted at the Milliken Station between July 15, 1993, and May 22, 1994, to test candidate materials of construction for the air heater cold-end heat pipes and outlet ductwork.

The testing utilized two types of corrosion probes. Both types used air cooling for temperature control. In this report, to differentiate between the two probe types, the first type will be referred to simply as "air-cooled probes" and the second type as "CAPCIS probes." The air-cooled probes were used to measure overall corrosion rates based on probe diameter changes over time. The CAPCIS probes used electronic sensors and a proprietary computer code to estimate the instantaneous corrosion rates. Diameter measurements of the CAPCIS probe sensing elements were used to confirm the CAPCIS corrosion rates and to adjust the corrosion rate coefficient in the corrosion software.

Probe Design

Figure 1 shows the general construction of the corrosion monitoring tip of the air-cooled probes. Two Cor-Ten A probes and one 2205 SS probe were constructed by CONSOL R&D for the test program.

As shown in Figure 1, the probe design consists of a 2" OD tube with a sealed base end. An external thermocouple (TC) at the probe base measures surrounding process gas stream temperatures. Three internal TCs welded to the wall of each probe provide surface metal temperatures and local gradients. Normally, the center wall TC (see view A-A) was connected to an on/off temperature controller which maintained the probe temperature to about ±5°F of the set point. An air line down the center of the probe provides cooling air to the probe tip. Heated air from the tip flows in the annular space between the air line and the probe wall and vents out the back end of the probe to the atmosphere. To remove fly ash deposits from the probe surface, there are three 1/4" dia. air nozzles spaced equidistance around the circumference.

To allow accurate location of reference diameter measurement points on the probes, circumferential and axial lines were scribed in the probe surface. The circumferential lines are spaced every 2" from the bottom end and the two axial lines are 60° apart. Measurements were always taken as close as possible to the circumferential-axial line intersection points.

The second type of corrosion probe was purchased from CAPCIS March Limited by NYSEG. Two probes (one made of SA-178A and one made of Cor-Ten B) were originally purchased by NYSEG for tests at the Kintigh Station in 1993. After the Kintigh Station tests, the probe sensing elements were refurbished by CAPCIS in SA-178A and Cor-Ten A.

The sensing end of a typical probe is shown in Figure 2. The sensor element consists of thirteen nominally 2.5" diameter metal rings made of the corrosion test material. The rings are separated by Viton® spacers and are wired to corrosion monitoring electronics. Voltage, current, and resistance signals from the probes are monitored by the electronics and converted to corrosion rates by CAPCIS software. The CAPCIS probes include an external TC for measuring the gas temperature around the sensing elements. Internal TCs are used to monitor and control the sensing element temperature. An air line down the center of the probe provides cooling air to the probe tip. Heated air from the tip flows back up the probe to the open end where it is vented to the atmosphere. Like the air-cooled probes, a cooling air on/off controller maintains metal temperatures.

After exposure to the flue gas environment, manual measurement of the sensing element diameters confirmed electronic indicated corrosion rates. The elements were measured across two orthogonal radii with the location of the gas TC as a reference.

Probe Location

The location, operating temperature, and operating period for each corrosion probe is shown in Figure 3. Start dates are different because the probes were installed as they became available.

The No. 1 Cor-Ten A air-cooled probe was installed on July 15, 1993, in Port 1 of the 2B flue gas duct (see Figure 4) running between the Milliken Station air heater outlet and the inlet to the ESP. At this location, the corrosion probe was exposed to a flue gas/fly ash/SO_3 environment similar to that at the cold-end outlet of the new heat pipe air heater. The probe was initially operated at target temperature of 172°F to simulate the cold-end design metal temperature for the full-scale heat pipe operating at a 250°F outlet flue gas.

During the corrosion test program, Milliken Station Units 1 and 2 operated with Ljungstrom air heaters. As shown in Figure 5, Ljungstrom air heaters generate large temperature gradients across the outlet ductwork. The No. 1 air-cooled probe was installed in a port where the flue gas temperatures were typically 240-260°F. The port location was selected based on the assumption that the severest corrosion might occur when the gas temperature is below the acid dew point.

On August 11, 1993, the first air-cooled probe was moved from Port 1 of Duct 2B to Port 9 of Duct 2A. This placed the probe in line with the No. 1 CAPCIS probe which was later installed in the 2A ESP outlet duct. In the new location, the No. 1 air-cooled probe could be used to directly compare ESP inlet/outlet corrosion rates since relatively little gas mixing occurs in ESPs. After completion of the ESP outlet corrosion monitoring program, the No. 1 air-cooled probe was moved to a high temperature region of Duct 2A because other corrosion probe tests indicated slightly higher corrosion rates for the high temperature zones.

The No. 2 air-cooled probe was also made of Cor-Ten A and was installed in a high temperature zone of Duct 2B. The probe was initially operated at a target temperature of 201°F to simulate the operating conditions for an alternate air heater design with flue gas outlet temperatures of 280°F. During the last stage of testing, the target control temperature for this probe was reduced to 172°F (174°F actual average).

The No. 3 air-cooled probe was made of 2205 duplex SS and was installed in a port next to the No. 1 air-cooled probe. Because of severe pitting attack, the probe was removed from service after only 35 days in operation.

On August 23, 1993, the No. 1 CAPCIS probe was installed in the outlet duct from the 2A ESP. This part of the program was to study corrosion in the ductwork downstream of the ESP and to monitor the corrosion in real time to see if process changes effected the corrosion rate. The flue gas temperature at the probe location was between 240°F to 250°F initially. The probe control temperature was set at about 230°F to simulate the temperature of insulated ductwork. Later, the probe temperature was set at 168°F (170°F target) to simulate a moderate cold spot which might exist due to ductwork insulation loss or to heat conduction through supports.

When the ESP tests were completed, the No. 1 CAPCIS probe was cleaned and sensing element dimensions were measured for an independent determination of corrosion rates. On February 7, 1994, the probe was relocated to the outlet duct of a pilot heat pipe. The heat pipe and a pilot NO_x reduction process were installed on a flue gas slipstream between the Milliken Unit 2B air heater inlet duct and the 2B ESP inlet. The No. 2 CAPCIS probe (Cor-Ten A material) was received from the supplier and installed at the heat pipe outlet.

These two probes were then used to monitor corrosion rates in flue gas containing fly ash, SO_3, and ammonia (NH_3); an environment which would exist downstream of the full-scale heat pipe if a NO_x reduction system was installed on Unit 2. The operating temperatures for the probes was maintained at about 172°F to simulate design cold-end temperatures in the full-scale heat pipe.

DISCUSSION

Air-Cooled Probe Temperatures

As shown in Figure 1, each of the air-cooled corrosion probes had three wall TCs to monitor metal temperatures. The TCs were spaced 2" apart and the center TC was normally used to control the cooling air purge rate. Figures 6, 7, and 8 show metal temperatures for corrosion probes 1, 2, and 3, respectively. The data are single point values taken once a day from locally mounted data recorder strip charts. For most of the testing, the probes were operated unattended. Gaps in the data, other than for probe inspections and dimensional measurements, are due to running out of chart paper or printer failures. Printer failures were caused by the high dust environment (above the Unit 2 ash silo) and to extreme cold temperatures. Except for a four-day period (2/7/94 to 2/10/94), the probe temperature control instrumentation was found to be functioning properly whenever printer failures were discovered. We assumed that probe temperatures remained close to desired set point temperatures during periods when data were not recorded.

The target operating temperature for the No. 1 air-cooled probe was 172°F for the 7/15/93 to 1/14/94 test period. As shown in Figure 6, the center control skin temperature normally remained within ±5 degrees of this target. The axial temperature gradient averaged about 12°F over the 4" distance from the coldest to hottest TC and was not linear with distance from the cold end.

The second time the air-cooled probes were removed from the system for inspection and dimension measurements, the top TC connector head for the No. 1 air-cooled probe was accidentally broken. The probe was reinstalled with only the bottom and middle TCs operational. Because of faulty wiring, control was switched to the bottom TC. Although the bottom TC temperature was controlled between about 172°F and 182°F, the control point change resulted in an increase in the average probe temperature. To place the operation on a common basis with other tests, an average temperature of 192°F for the period 2/5/94 to 5/22/94 is used based on the center TC reading for reference.

The temperature data for the No. 2 air-cooled probe is presented in Figure 7. For the first test period (7/29/93 to 1/14/94), the target control temperature was 202°F. This was achieved and temperature control was stable with the middle or center control temperature remaining within about ±5°F of the set point. Because corrosion rates were low for 202°F operation, the target control temperature was lowered to 172°F (174°F actual value achieved) for the 2/5/94 to 5/22/94 test period. Again, temperature control was stable.

Figure 8 presents the temperature data for the No. 3 air-cooled probe. As for the other two probes, the temperature control was tight and stable.

Air-Cooled Probe Corrosion Rates

Table 1 summarizes the corrosion data for the air-cooled probes based on diameter measurements. For each probe, diameter measurements were taken at eight locations along two axial scribe lines (see Figure 1). The probe dimensional measurements are presented in Appendix Tables 1A, 2A, and 3A. The data summarized in Table 1 are average corrosion rates taken over the length of the probe. Average rates are presented since the bulk of the data do not show a general corrosion rate trend with distance from the cold end (see Figures 9 to 15). Table 1 results show that overall corrosion rates for all temperatures investigated were low. The rate averaged generally less than 2 mils/yr. This indicates that Cor-Ten A should hold up well in the low temperature end of the full-scale heat pipe.

The results also indicate a low average corrosion rate for 2205 SS ranging from 0.9 to 2.5 mil/yr. However, as discussed in the Corrosion Probe Inspections Section, severe surface pitting corrosion occurred in areas covered by fly ash deposits. Areas where deposits were absent had smooth uncorroded surfaces. The likely cause of the corrosion is sulfuric acid attack under the deposits. Because of the pitting attack, the 2205 SS material was not tested further.

The negative corrosion rates shown in Figures 9, 10, 11, and 12 can be attributed to: (1) errors in reading the caliper correctly, (2) errors associated with not duplicating exactly the measurement locations at the beginning and end of a test, and (3) the presence of a surface deposit. Efforts were made to minimize all the aforementioned errors by: having the same technician do all the measurements with the same caliper (which was stored and not used between measuring periods), providing scribe marks on the probes for caliper positioning, and by carefully cleaning the probes. Appendix Tables 1A and 4A present data where the technician was asked to repeat measurements without reference to the original readings. Pooled standard deviations of the differences in the readings for the air-cooled probes ranged from 0.00011" to 0.00016" and for the CAPCIS probes 0.00044" to 0.00059" at 95% confidence level. These results mean that the technician was generally able to find the correct measurement location and to measure the probe or sensor element diameters to about the resolution accuracy of the calipers, which for the air-cooled probes was 0.0001" and for the CAPCIS probes was 0.0005". Due to the narrowness of the CAPCIS probe sensor elements, a second caliper with a resolution of 0.0005" had to be used for these diameter measurements.

Since corrosion rates were very low and the test times relatively short, the accuracy of the calculated rates was also low. Often, the reported rate is similar to the potential error that could occur due to caliper resolution (i.e., (2 x caliper resolution x 8760000)/(2 x test hours) = mils/yr). In other words, the maximum measurement error would be generated if the beginning and ending diameter measurements for a point were each off in opposite directions by the caliper resolution. For the air-cooled probes, diameter changes greater than 0.0002" were required for the measured corrosion to be greater than the maximum error associated with caliper resolution. For the CAPCIS probes the actual corrosion had to be 5 times this value (i.e., exceed 0.001") due to the need to use a poorer resolution caliper.

System SO_3 Levels

The flue gas SO_3 data which were taken at various times throughout the test program are shown in Table 2. The ESP inlet data were not taken at a specific corrosion probe port location, but are average duct values based on a composite sample of ten port traverses. In all cases, the flue gas temperatures were at least slightly above the estimated acid dew points. Since corrosion probes were normally operated at 170°F-201°F, the probe temperatures were usually far below the ambient acid dew points. As a result, acid condensation on the probes was likely. The low measured corrosion rates indicate that the fly ash may provide protection by neutralizing some of the acid.

The flue gas particulate loadings were not determined for the SO_3 measurements. However, the SO_3 content of the solids collected on fiber glass filter plugs used at the inlet of the sampling probes was determined. These data show a trend of higher SO_3 levels on flue gas solids with declining flue gas temperature. It is likely that sulfuric acid is absorbing on the solids/filter or condensing in the pores of the solids as the dew point temperature is approached.

The ESP outlet data for the location where the SA-178A CAPCIS probe was installed shows a low level of SO_3 in the gas phase and a very high proportion of the total SO_3 on the solids collected by the probe filter plug. Again, this indicates either acid condensation or absorption on the very small amount of particulate present at this location, or the presence of an acid fog. The fact that the flue gas temperature at the ESP outlet was 8°F above the estimated acid dew point argues against acid fog formation. However, the temperatures are close; and the dew point is an estimated, not a measured, value. As a result, some fog may have formed.

CAPCIS Probe Corrosion Rates

Table 3 presents a summary of the CAPCIS probe corrosion rate data including both the manually determined corrosion rates and the integrated rates based on electro-chemical responses from the probes. Detailed data for the manually determined corrosion rates are presented in Tables 4A through 7A in the Appendix while the daily average electro-chemical signal results are presented in Appendix Tables 8A through 10A.

ESP Outlet Results. At the ESP outlet, the SA-178A CAPCIS corrosion probe was purposefully located on the side of the ESP where temperatures were low due to the operation of the upstream Ljungstrom air heater. In this location, the flue gas would be at, or near, the SO_3 acid dew point and the probe would be exposed to any acid fog which might be produced by the air heater operation.

The manually determined corrosion rates for SA-178A were low and ranged from 0.2 to 1.9 mils/yr for probe operation at 231°F, and 0.1 to -0.6 mils/yr for probe operation at 168°F. The corrosion rate absolute values are suspect since they fall below the maximum error due to caliper resolution (2.9-2.7 mils/yr for the two test periods, respectively). The bottom line is that the actual corrosion rates are low and are less than 2.9-2.7 mils/yr.

Figure 16 shows the continuous corrosion rate response of the SA-178A probe for two test periods. Corrosion rates were low for both test periods. No correlation was found between corrosion rate and either flue gas temperature or probe temperature (see Figures 17 and 18).

Based on CAPCIS corrosion monitoring system output, the average corrosion rate at the 231°F temperature level was 2.3 mils/yr. This compares reasonably well with the 0.2 to 1.9 mils/yr rates based on measured probe diameters. The comparison was not as good for the 168°F test where the CAPCIS system rate was 1.9 mils/yr versus -0.6 to 0.1 mils/yr for rates based on diameter measurements. However, the standard deviations for the manually measured corrosion rates are high, so the actual corrosion rate should fall between the sample estimate rate and ± about two standard deviations with 90 to 95% confidence. For the -0.6 mils/yr calculated average, the population mean is expected to fall between 0.0 mils/yr and 5.1 mils/yr. For the 0.1 mils/yr calculated average, the population mean should fall between 0.0 mils/yr and 1.7 mils/yr. Similarly, for the probe responses, the mean corrosion rate for the 168°F operation should fall between 0.5 mils/yr to 3.3 mils/yr.

As shown in Figure 16, during the last month of testing (December 1993 to January 1994), rates tended to vary more widely, fluctuating between <1 mils/yr to about 4 mils/yr. This may have been due to changes in the probe surface deposit chemistry caused by the rather low (208°F to 230°F) and variable flue gas temperatures.

The low level of corrosion at the ESP outlet is somewhat surprising since there are few solids present which might neutralize acid. When the probe was operated at 168°F, the metal was far below the acid dew point (i.e., 218°F see Table 2). A similar situation occurred during the 1993 Kintigh Station tests with the CAPCIS probes. For probe temperatures up to 160°F, corrosion rates as high as 20 mils/yr were recorded by the carbon steel CAPCIS probe in a high SO_3 environment with no fly ash. However, when probe temperatures were increased to 175°F, the corrosion rate dropped to <5 mils/yr. This indicates perhaps, that the acid deposition rate on the probes decreased substantially at the higher temperatures or that the surface chemistry changed.

Slipstream Heat Pipe Outlet Results. At the slipstream heat pipe outlet, the corrosion probes were exposed to an environment containing fly ash, SO_3, and ammonia (NH_3). At this location, SO_3 and NH_3 levels tended to vary considerably due to changes in the outlet temperature of the heat pipe and to variable testing of the upstream pilot NO_x removal process. The average CAPCIS system corrosion rate for SA-178A operated at 176°F was 4.2 mils/yr. For comparison, rates based on measured probe diameters were between 2.9 and 3.5 mils/yr (see Table 3). These manually determined values should be reasonably accurate since rates were above the expected maximum error of 1.8 mils/yr due to caliper resolution. The good agreement between the CAPCIS system rate and the rate based on diameter changes indicates that the corrosion rate coefficient, which was determined for carbon steel during tests at the Kintigh Station in 1993, still holds for the Milliken tests.

In Figure 19, the indicated probe corrosion rate for SA-178A and the flue gas and probe temperatures are plotted for the test duration. The plot shows a general low level of corrosion for most of the test period with an increase in the corrosion rate during the two week shutdown period. The shutdown period corrosion rate increase was probably caused by changes in the chemistry of probe deposits or corrosion products. Hydration of corrosion products such as iron sulfates, or condensed sulfuric acid, may have occurred and caused the indicated corrosion rate increases. During the last week of operation, the CAPCIS system corrosion rates were higher than during the first four months of operation. However, for the last three operating days, corrosion rates declined steeply towards the previous levels.

For the general surface corrosion experienced during the Milliken tests, the corrosion rate is calculated by:

$$R = 4.39x10^8(ECN) \qquad (1)$$

Where:

ECN = *Electro Chemical Noise Signal, amps*

R = *Overall Corrosion Rate, mils/yr*

Figure 20 presents the on-line indicated corrosion rate data for the Cor-Ten A probe based on this calculation. The average overall indicated rate is almost seven times the rate based on measured diameters (see Table 3). This means that the corrosion rate coefficient developed for Cor-Ten B during the 1993 Kintigh Station tests does not hold for the new Cor-Ten A probe. The current results indicate that the coefficient should be $6.44x10^7$ mils/(yr-amp). Using the new coefficient, the corrosion rates for Cor-Ten A are replotted in Figure 21.

A comparison of Figures 19 and 21 shows that switching from 1.4% S to 2.8% sulfur coal did not cause a significant change in the indicated corrosion rates of either SA-178A or Cor-Ten A materials. Both indicated corrosion rates tended to drift lower while the high sulfur coal was fired. This is a desirable result, however, the testing may not have been long enough to assess the impact of coal sulfur changes. The two figures show a difference in the corrosion responses of the two CAPCIS probes during the shutdown period (4/29/94 to 5/14/94). Higher corrosion rates were indicated for SA-178A and lower rates for Cor-Ten A. The difference is probably due to the chemistry of the protective scale which supposedly forms on the Cor-Ten material. When the two probes were placed back in service, the corrosion rate for the SA-178A probe was somewhat higher than before the shutdown; while the rate for the Cor-Ten A probe was about the same as before the shutdown.

Figures 22 and 23 present the corrosion rate data for the SA-178A CAPCIS probe plotted against flue gas temperature and probe temperature, respectively. Neither figure shows a temperature trend for corrosion. The figures do show higher rates of corrosion for the last week of operation (5/14/94 to 5/22/94). Also, erratic and high levels of corrosion are indicated during the shutdown period when hydration of surface deposits may have occurred.

Similar plots for the Cor-Ten A CAPCIS probe are provided as Figures 24 and 25. Figure 24 indicates a trend of slightly higher corrosion with decreasing flue gas temperatures in the range of about 230°F to 330°F. No trend was established for probe temperature nor would one be expected since the temperature was tightly controlled at one level. A comparison of Figures 23 and 25, however, shows that the temperature control for the Cor-Ten A probe was much better than that for the SA-178A probe. This indicates the need for equipment maintenance to improve the temperature control of the carbon steel probe. As mentioned above, Figures 23 and 25 clearly show the much lower corrosion rate for Cor-Ten A over SA-178A during the shutdown period.

The average daily NH_3 slip from the upstream NO_x control process to the heat pipe and the CAPCIS probe corrosion rates are shown in Figures 26 and 27. During the Kintigh Station corrosion tests, the presence of NH_3 in the flue gases appeared to increase the corrosion rate for Cor-Ten B material. At a 2 ppmv level, corrosion rates up to 60 mils/yr were recorded at temperatures up to 175°F and rates were still 15-20 mils/yr at temperatures as high as 230°F. For SA-178A ammonia appeared to provide some protection. For the current tests, the level of NH_3 does not appear to increase the corrosion rate of either SA-178A or Cor-Ten A materials.

Corrosion Probe Inspections

Typical corrosion probe installations are shown in Figures 28 and 29 for the air-cooled and CAPCIS probes, respectively. The condition of the air-cooled probes when they were removed for the first inspection are shown in Figures 30, 31, and 32. As shown in Figure 28, the air-cooled probes were installed horizontally, with flue gas flow vertically upward through the duct. For these probes, fly ash deposits tended to accumulate on the bottom or windward side with little or no deposits on the top or leeward side.

When the air-cooled probes were withdrawn from the ductwork, the surface fly ash deposits were always crusty and appeared bone dry. With exposure to ambient air, the deposits would become damp or even wet, would swell, and begin to flake off. Figures 33, 34, and 35 show the first inspection condition of the two Cor-Ten A and the 2205 SS air-cooled probes one day after removal from the Milliken ductwork. During this period, the ambient humidity was relatively high so probe sweating began quickly. As shown in the figures, the deposits became dark in color and began to spall from the probe. The 2205 SS probe became wet with a yellowish, oily liquid forming under the deposits. The water absorption by the deposits is likely due to hydration of condensed sulfuric acid or iron sulfate corrosion products. It is likely that a significant amount of corrosion occurs when this happens. In the Figure 36 close-up view of the No. 1 air-cooled Cor-Ten A corrosion probe, the deposits appear as blisters; some of which have erupted open. This indicates a high rate of corrosion with gas generation when the deposits absorbed water from the air.

Figure 37 presents a close-up view of the 2205 SS air-cooled corrosion probe before cleaning. In the figure, the area not covered by deposits is smooth and uncorroded but areas covered by deposits are corroded and highly pitted. Clearly, the presence of the fly ash deposits is a factor in the corrosion of 2205 SS.

In the book "Dew Point Corrosion,"[1] it is pointed out that fly ash deposits containing residual amounts of sulfuric acid are hygroscopic and will become damp during off-load or shutdown periods. The hydrolysis of potassium, aluminum, and iron sulfates formed from the ash and metal work will create an acidic film on metal surfaces and lead to further corrosion. However, the off-load corrosion can be essentially eliminated if the relative humidity (RH) is reduced and maintained at 33% or less[2]. Based on the current program results, it is recommended that the RH in the ductwork be controlled, if feasible, to minimize corrosion in the air heater during shutdown periods. Possible control methods are to: (1) circulate dehumidified air or, (2) slightly heated air through the flue gas side of the heat pipe and downstream ductwork. As an example, with ambient conditions at 80°F and 60% RH, heating the air with a steam coil heater to 98°F would reduce the RH to 33%.

Overall and close-up views of the cleaned air-cooled probes after the first inspection for dimensional measurements are shown in Figures 38 to 43. Figures 38 and 39 show little or no corrosion on the No. 1 air-cooled probe. The machine marks on the No. 1 probe are clearly visible in Figure 39. Because of short notice for construction, two machinists were used to manufacture the probes. This resulted in differences in the probe surface dressings with the No. 1 probe being coarse and the other two fine.

Figures 40 and 41 also show very little surface attack of the No. 2 air-cooled Cor-Ten A probe after 832 hours of service. Only a slight discoloration of the cold-end tip can be seen in Figure 41, where temperatures were below about 185°F (see Figure 7). However, for this same short test period, severe corrosion of the 2205 SS probe is clearly indicated in Figures 42 and 43. The pitting extended the entire length of the probe. The probe was not tested further because the corrosion resistance was not adequate for the test environment.

Figure 44 is an overall view of a cleaned No. 1 air-cooled Cor-Ten A probe taken at the end of all testing. The probe had been operated (middle thermocouple) at nominally 172°F for 3832 hours and at 192°F for 2474 hours. As shown in the figures, this probe suffered little corrosion. At the end of testing, the coarse machine marks were still clearly visible for this probe.

Overall and close-up views of the No. 2 air-cooled probe are shown in Figures 46 and 47, respectively. This probe had been operated at nominally 201°F for 3496 hours and at 174°F for the last 2378 hours. Generally, the probe showed little or no corrosion except for the bottom 4" and in one other area 10"-12" from the bottom end. Corrosion of the bottom end was not unexpected since temperatures were below 160°F over the last 2378 hours of operation. During the period when the No. 1 air-cooled probe was operated at 172°F, the probe was installed in an area where flue gas temperatures were low due to the operation of the upstream Ljungstrom air heater (see Figures 3 and 4). In such downstream areas from Ljungstrom units, flue gas SO_3 levels are often greatly reduced because of condensation in the Ljungstrom. A lower SO_3 flue gas level would explain why the No. 2 air-cooled probe shows less corrosion than the No. 1 probe.

The area of high localized attack for the No. 2 air-cooled probe is shown in Figures 48 and 49. The corrosive attack appeared along an interface line between a fly ash deposit covered area and a deposit-free area. The corrosion occurred on the probe where temperatures were much higher than the control temperature so corrosion would be expected to be generally low. Figure 48 shows that the corroded area is directly downstream of one of the air sootblower nozzles. One possible explanation is that the sootblower operation did not remove the deposits, but rather cooled them momentarily allowing residual acid to absorb moisture. This briefly diluted the acid, making it more corrosive. Alternately, it may be that in this area, the neutralizing capacity of the deposits was depleted. The deposits became acid soaked and this lead to attack of the underlying metal. Sootblowers must provide adequate removal of fly ash deposits before the deposits become acid soaked to prevent this form of corrosion.

The conditions of the CAPCIS probes immediately after removal from the system following the ESP and slipstream heat pipe tests are shown in Figures 50 to 52. Each time the probes were removed for sensing element dimension measurements, the elements had a uniform corrosion scale. This scale, the rust-colored coating shown in the figures, is required for proper operation. For the ESP tests, only the SA-178A probe was installed. As expected, there were never any ash deposits on the probe. The probes removed from the slipstream heat pipe outlet were, however, coated with fly ash solids.

Figures 53 and 54 are close-up views of the cleaned sensing elements for the SA-178A and Cor-Ten A probes, respectively. The photographs show the final condition of the probes at the end of the testing. The surface of the SA-178A probe appears slightly rougher than that of the Cor-Ten A probe. This is to be expected since the probe was in operation longer and the manually measured corrosion rates for the SA-178A probe are about double those of the Cor-Ten A probe.

There was one interesting observation concerning the corrosion scales on the SA-178A probe. The scale was easily removed following the ESP operations by scrubbing the sensing elements using Bon-Ami™, water, and a plastic scrub pad. The scale formed during the slipstream operations when the probe was exposed to fly ash, SO_3, and NH_3 was extremely tight and hard. Using the plastic scrub pad and Bon-Ami only caused spotty chipping of the scale. To speed up the scale removal so that the corroded diameters of the sensing elements could be measured, inhibited HCl solution (5g/l 1,3,Dibutyle-2-thiourea) was used. This quickly removed the deposit and provided a very clean surface.

REFERENCES

1. Holmes, D. R., ed. "Dew Point Corrosion," John Wiley & Sons, New York, N.Y., 1985, p. 64.

2. ibid., pp. 69-70.

Table 1
Corrosion Rates For Air-Cooled Probes
(Based On Dimension Changes)

Probe No.	1					
Location	Unit 2 Air Heater Outlet					
Port # - Duct	#1 - 2B/#9 - 2A		#1 - 2B/#9 - 2A		#4 - 2A	
Material	Cor-Ten A					
Period	7/15/93 - 9/2/93		7/15/93 - 1/14/94		2/05/93 - 5/22/94	
Operating Hours	1168		3832		2474	
Avg Probe Control Temp, deg F	172		172		192	
Avg Gas Temp, deg F	256		243		278	
Avg Corrosion Rate, mils/yr						
Axial Scribe Line "A"	1.1	0.7 SDEV	0.6	0.2 SDEV	0.5	0.6 SDEV
Axial Scribe Line "B"	0.0	0.7 SDEV	0.1	0.1 SDEV	0.7	0.2 SDEV
Potential Rate Error Due To Caliper Resolution of 0.0001", mils/yr	0.8		0.2		0.4	
Probe No.	2					
Location	Unit 2 Air Heater Outlet					
Port # - Duct	#5 - 2B		#5 - 2B		#6 - 2B	
Material	Cor-Ten A					
Period	7/29/93 - 9/2/93		7/29/93 - 1/14/94		2/05/94 - 5/22/94	
Operating Hours	832		3496		2378	
Avg Probe Control Temp, deg F	201 (1)		201 (1)		174 (2)	
Avg Gas Temp, deg F	287		279		276	
Avg Corrosion Rate, mils/yr						
Axial Scribe Line "A"	1.8	1.1 SDEV	1.3	0.3 SDEV	0.9	0.8 SDEV
Axial Scribe Line "B"	1.3	1.7 SDEV	0.9	0.9 SDEV	0.9	0.8 SDEV
Potential Rate Error Due To Caliper Resolution of 0.0001", mils/yr	1.1		0.3		0.4	
Probe No.	3					
Location	Unit 2 Air Htr Outlet					
Port # - Duct	#2 - 2B/#8 - 2A					
Material	2205 SS					
Period	7/29/93 - 9/2/93					
Operating Hours	832					
Avg Probe Control Temp, deg F	170 (2)					
Avg Gas Temp, deg F	265					
Avg Corrosion Rate, mils/yr						
Axial Scribe Line "A"	2.5	1.5 SDEV				
Axial Scribe Line "B"	0.9	0.3 SDEV				
Potential Rate Error Due To Caliper Resolution of 0.0001", mils/yr	1.1					

(1) Temperature Control Target 202 deg F.

(2) Temperature Control Target 172 deg F.

Table 2
Flue Gas SO2/SO3 Levels
Milliken Station

Date Location Number of Samples	09/01/93 CAPCIS Probe Port Unit 2 ESP Outlet 3		01/13/94 Slipstream Heat Pipe Outlet (1) 4		04/21/94 Slipstream Heat Pipe Outlet (1) 2		04/17/94 ESP Inlet Duct Duct 2A 2 (2)		04/17/94 ESP Inlet Duct Duct 2B 2 (2)	
	Avg	SDEV	Avg	SDEV	Avg	SDEV	Avg	SDEV	Avg	SDEV
Flue Gas Temp, deg F	226	12	315	1	259	16	276	1	267	1
SO2										
@ Duct Conditions, ppmv	671	46	1042	24	982	4	1011	3	1007	37
@ 0% Oxygen, ppmv	1125	21	1472	33	1523	11	1554	12	1525	7
SO3 (Gas Phase)										
@ Duct Conditions, ppmv	0.5	0.12	5.7	1.00	1.3	0.78	3.4	0.21	4.4	0.28
@ 0% Oxygen, ppmv	0.9	0.21	8.1	1.41	2.0	1.20	5.2	0.21	6.6	0.71
% Total SO3 on Solids	43.5	6.27	4.6	1.94	38.4	35.14	17.8	6.29	15.0	3.54
Approx Acid Dewpoint, deg F	218		262		235		251		256	

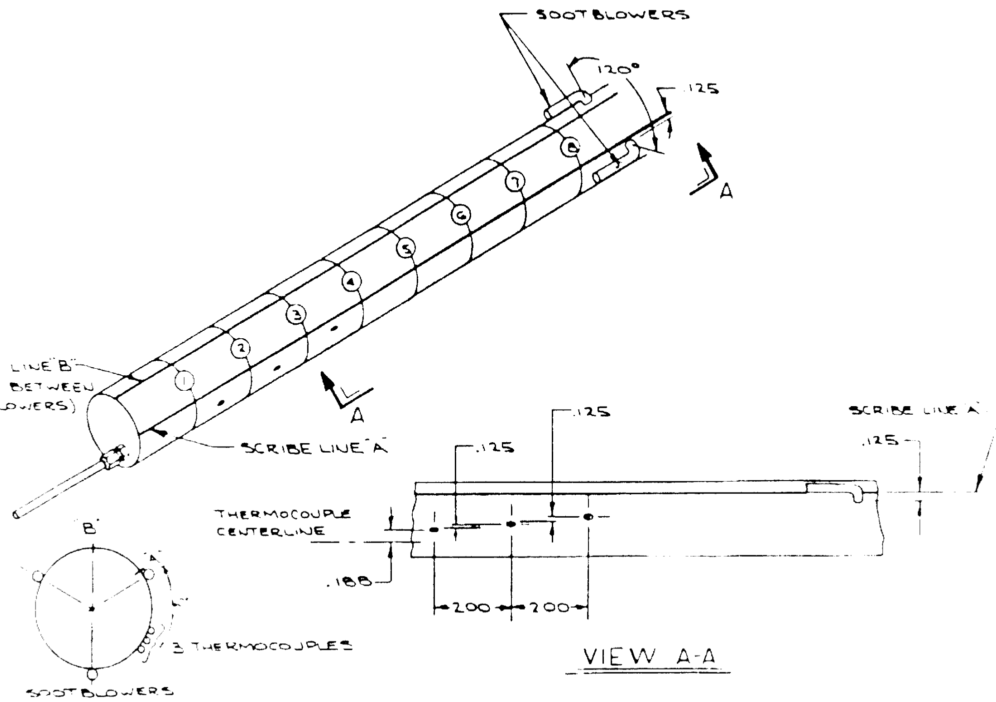
(1) Note heat pipe was located downstream of SCR catalyst beds which caused some SO2 conversion to SO3.
(2) Each sample was a 10 port composite with 3 points at each port.

Table 3
Corrosion Rates For CAPCIS Probes
(Based On Electronic Results and Dimension Changes)

Probe No.	1		1	
Location	Unit 2 ESP Outlet		Unit 2 ESP Outlet	
Material	SA-178A		SA-178A	
Period	8/25/93 - 10/27/93		11/08/93 - 1/14/94	
Operating Hours	1501		1609	
Avg Probe Control Temp, deg F	231		168	
Avg Gas Temp, deg F	235		221	
Avg Corrosion Rate, mils/yr				
Probe Indicated Rate	2.3	0.6 SDEV	1.9	0.7 SDEV
Based On Measured Dimensions				
Orientation "A" (1)	0.2	2.3 SDEV	0.1	0.8 SDEV
Orientation "B" (1)	1.9	1.9 SDEV	-0.6	2.9 SDEV
Potential Rate Error Due To Caliper Resolution of 0.0005", mils/yr	2.9		2.7	
Probe No.	1		2	
Location	Heat Pipe Outlet		Heat Pipe Outlet	
Material	SA-178A		Cor-Ten A	
Period	2/07/94 - 5/22/94		2/07/94 - 5/22/94	
Operating Hours	2487		2487	
Avg Probe Control Temp, deg F	176		174	
Avg Gas Temp, deg F	283		282	
Avg Corrosion Rate, mils/yr				
Probe Indicated Rate (2)	3.4	2.6 SDEV	13.5	5.6 SDEV
Probe Indicated Overall Rate (3)	4.1	4.2 SDEV	12.3	6.3 SDEV
Based On Measured Dimensions				
Orientation "A" (1)	3.5	0.7 SDEV	1.7	0.5 SDEV
Orientation "B" (1)	2.9	1.0 SDEV	1.9	0.5 SDEV
Potential Rate Error Due To Caliper Resolution of 0.0005", mils/yr	1.8		1.8	

(1) See Appendix Tables 4A, 5A, 6A, and 7A for orientation.
(2) Corrosion rates for shutdown periods not included.
(3) Corrosion rates for shutdown periods included.

Figure 1
Corrosion Probe Tip Construction



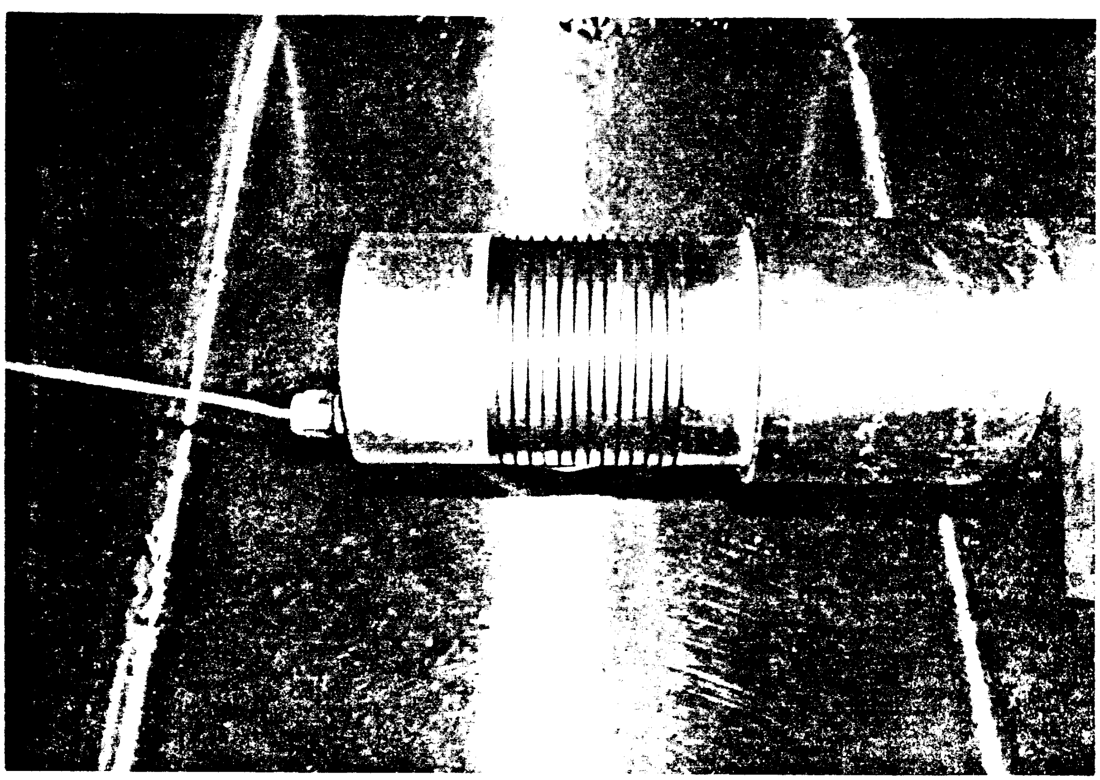
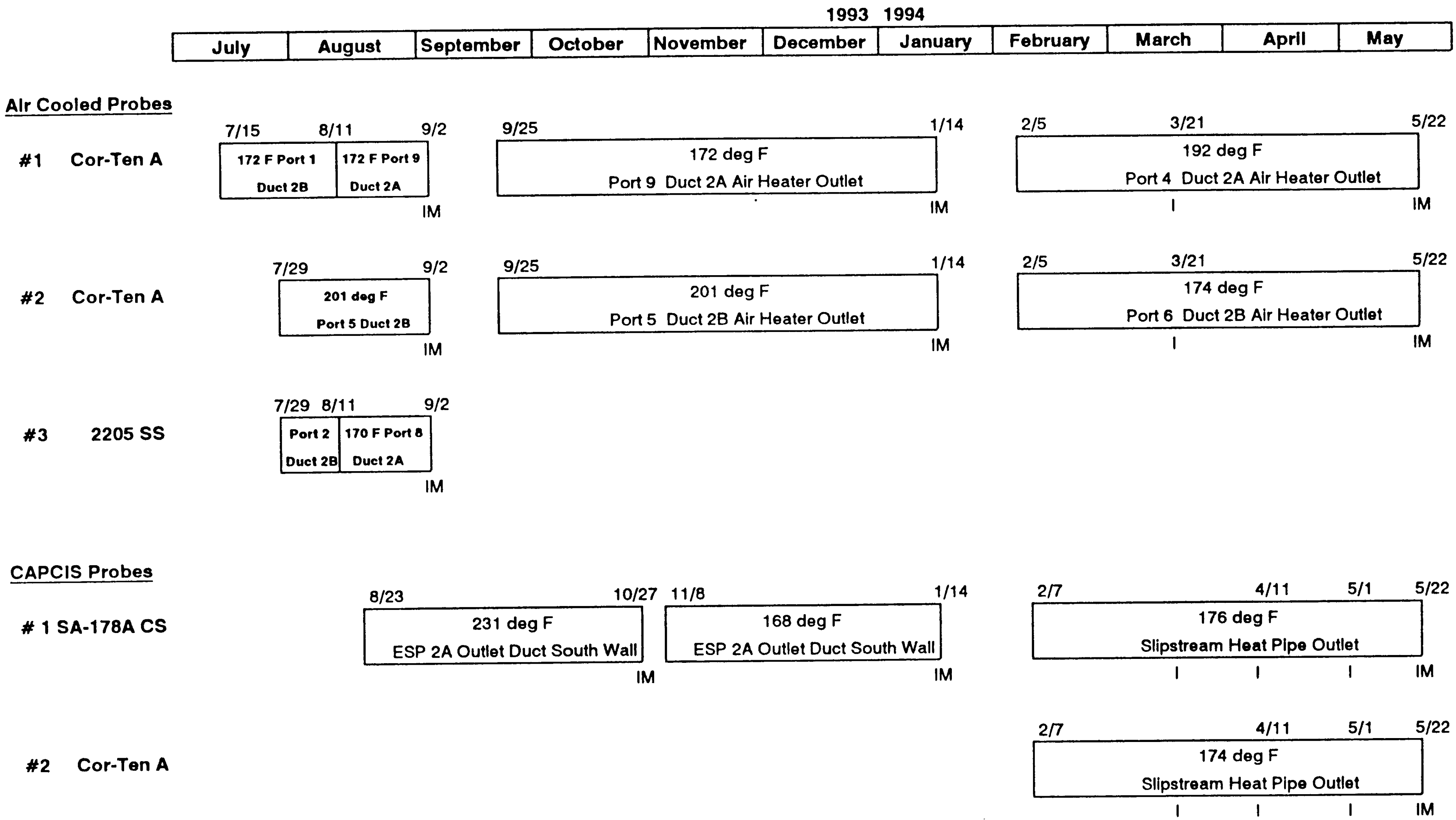


Figure 2. Sensor end of CAPCIS probe. External gas thermocouple and the thirteen sensing elements are shown. Sensing elements are separated by Viton® spacers.

Figure 3
Corrosion Probe Operating Times
Milliken Station July 1993 to May 1994



I = Inspection

IM = Inspection & Dimensions Measurement

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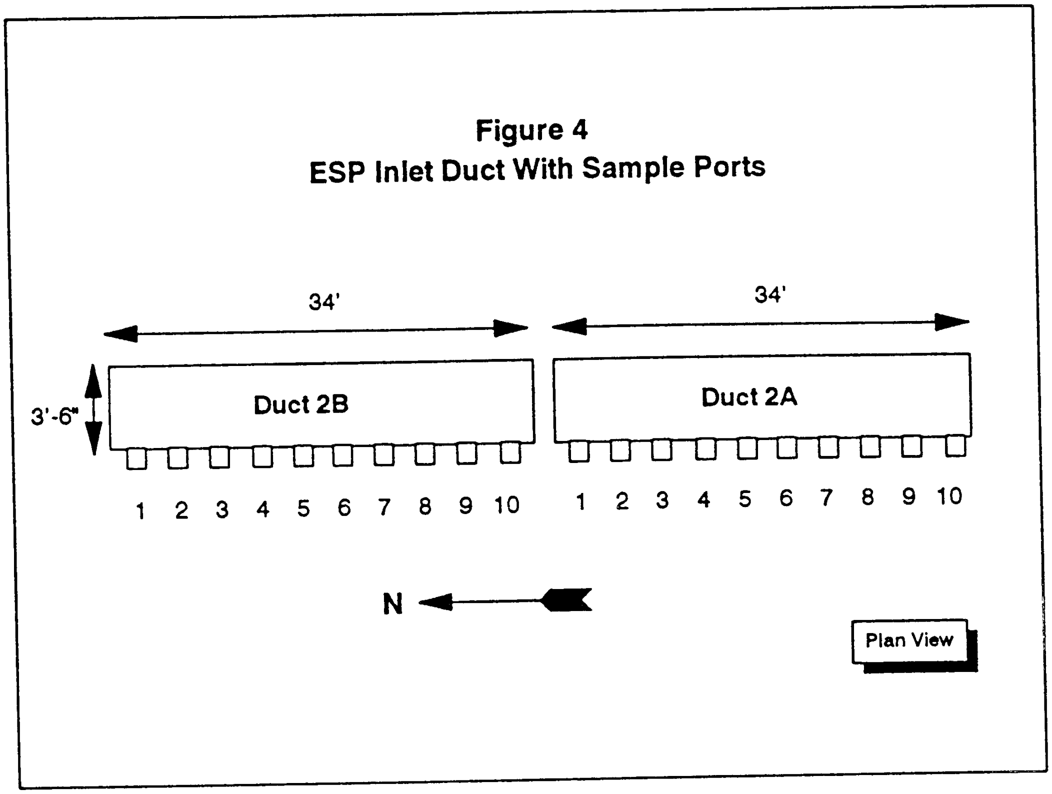


Figure 4
ESP Inlet Duct With Sample Ports
34'
34'
3'-6"
Duct 2B
Duct 2A
1 2 3 4 5 6 7 8 9 10
1 2 3 4 5 6 7 8 9 10
N
Plan View

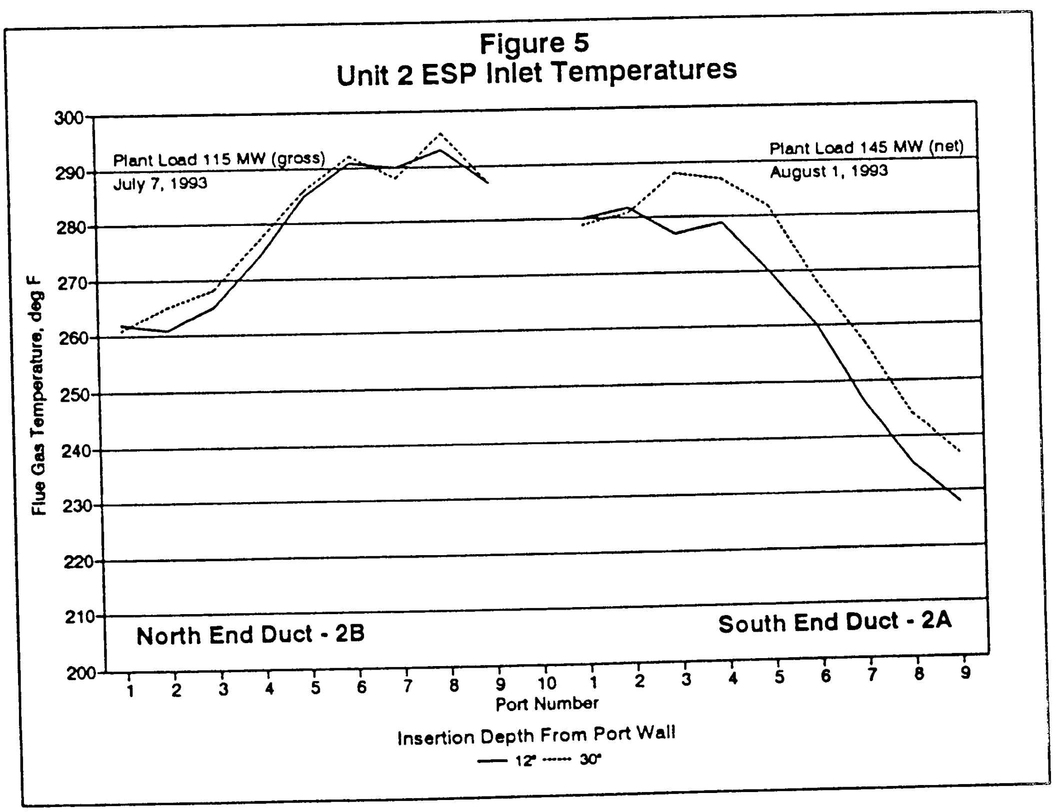


Figure 5
Unit 2 ESP Inlet Temperatures
Plant Load 115 MW (gross)
July 7, 1993
Plant Load 145 MW (net)
August 1, 1993
Flue Gas Temperature, deg F
300
290
280
270
260
250
240
230
220
210
200
North End Duct - 2B
South End Duct - 2A
1 2 3 4 5 6 7 8 9 10 1 2 3 4 5 6 7 8 9
Port Number
Insertion Depth From Port Wall
12" 30"

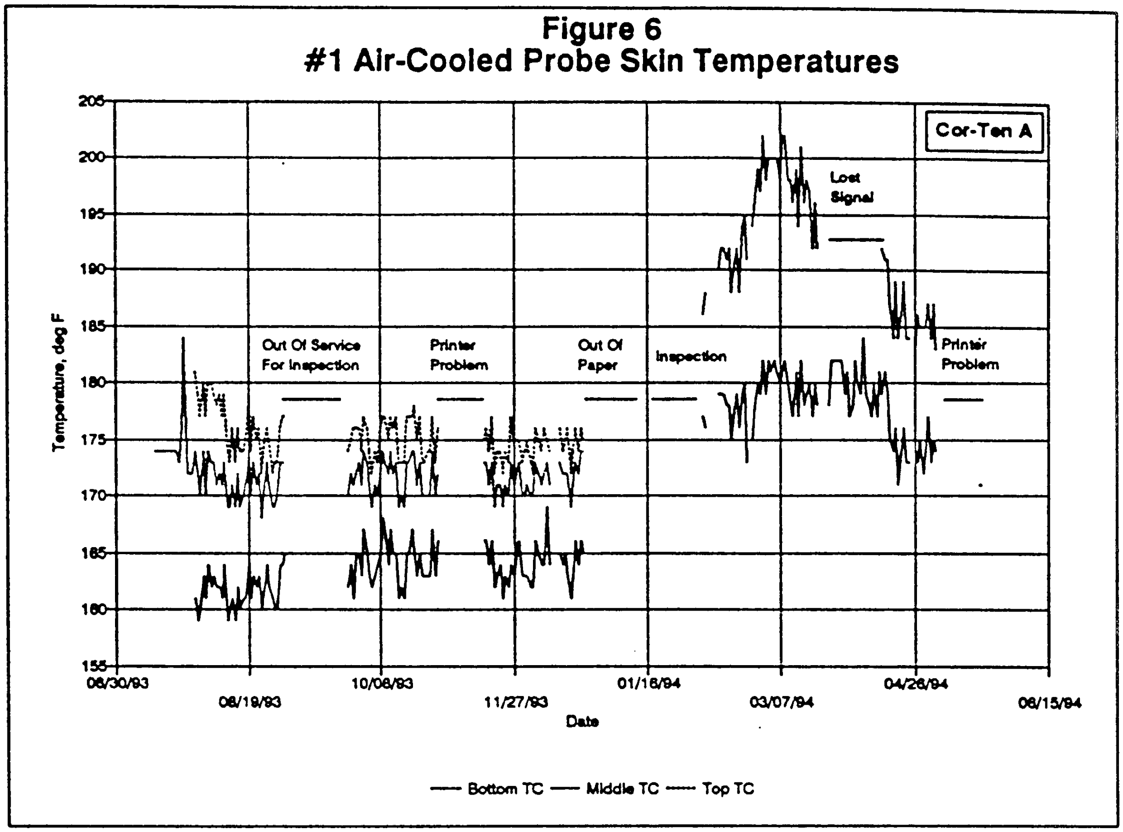


Figure 6
#1 Air-Cooled Probe Skin Temperatures
Cor-Ten A
Lost Signal
Out Of Service For Inspection
Printer Problem
Out Of Paper
Inspection
Printer Problem
Temperature, deg F
Date
08/30/93
08/19/93
10/08/93
11/27/93
01/16/94
03/07/94
04/26/94
06/15/94
Bottom TC
Middle TC
Top TC

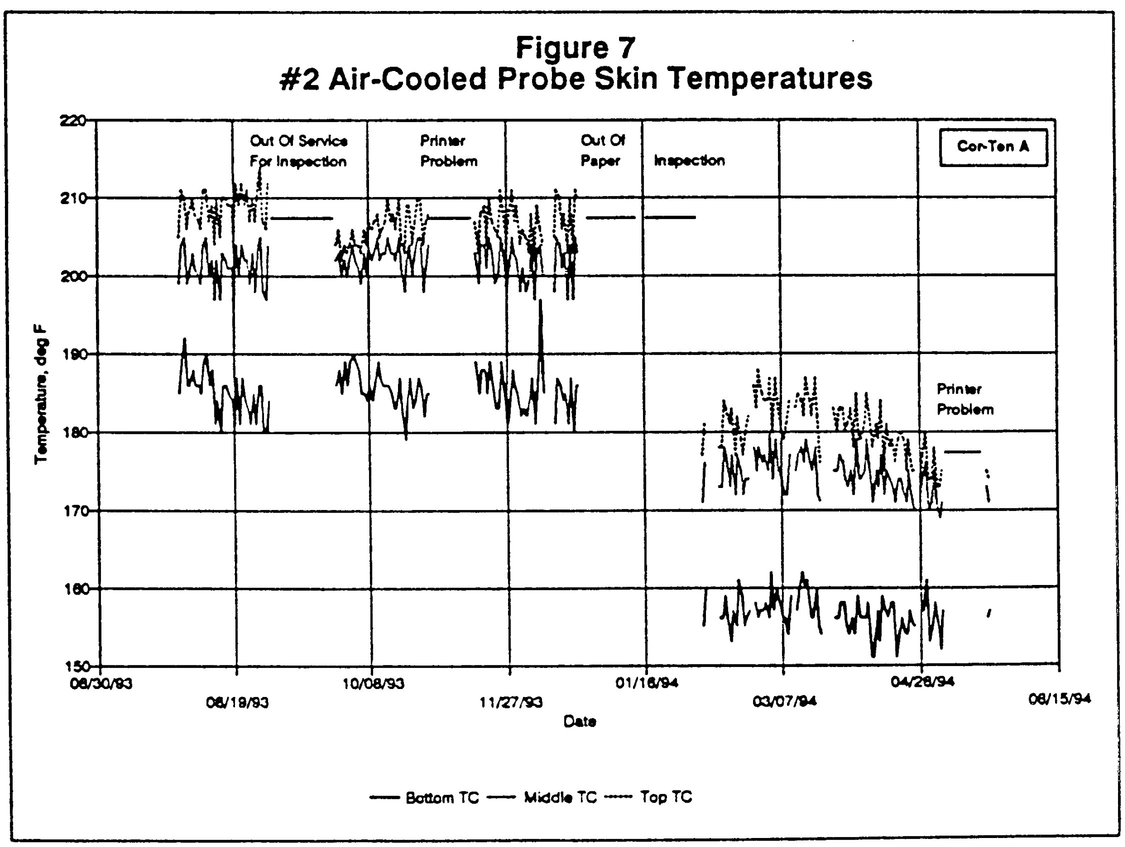


Figure 7
#2 Air-Cooled Probe Skin Temperatures
Out Of Service For Inspection
Printer Problem
Out Of Paper
Inspection
Cor-Ten A
Printer Problem
Temperature, deg F
Date
08/30/93
08/19/93
10/08/93
11/27/93
01/16/94
03/07/94
04/26/94
06/15/94
Bottom TC
Middle TC
Top TC

224

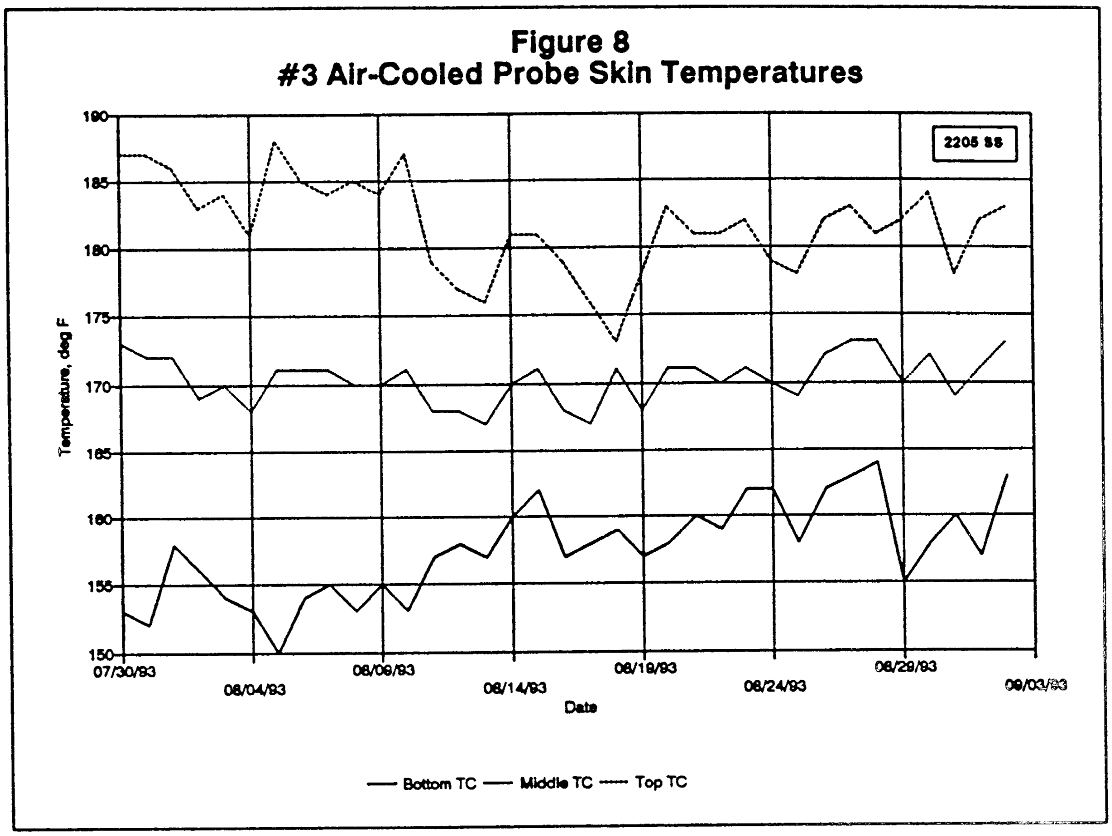


Figure 8
#3 Air-Cooled Probe Skin Temperatures
2205 SS
Temperature, deg F
190
185
180
175
170
165
160
155
150
07/30/93
08/04/93
08/09/93
08/14/93
08/19/93
08/24/93
08/29/93
09/03/93
Date
Bottom TC
Middle TC
Top TC

225

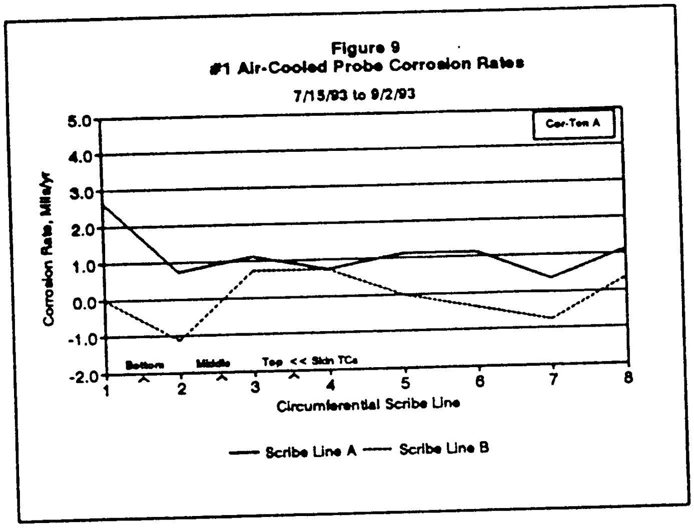


Figure 9
#1 Air-Cooled Probe Corrosion Rates
7/15/93 to 9/2/93

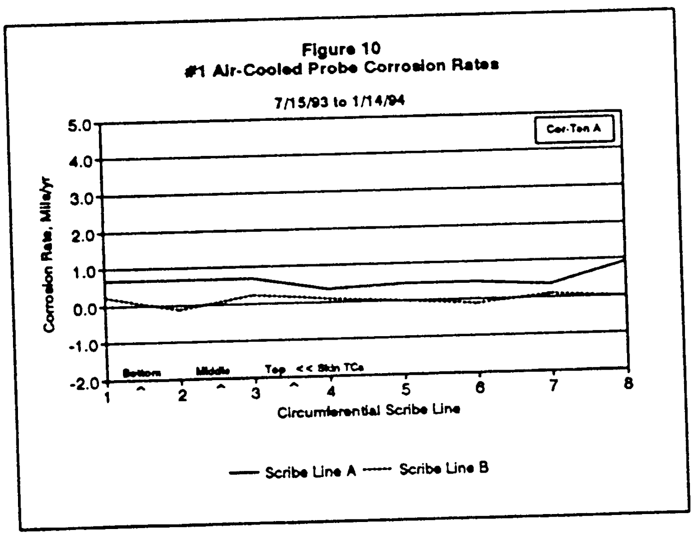


Figure 10
#1 Air-Cooled Probe Corrosion Rates
7/15/93 to 1/14/94

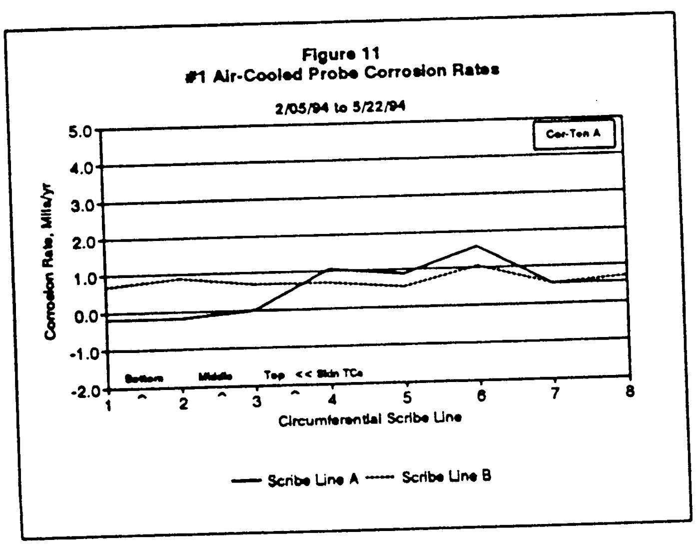


Figure 11
#1 Air-Cooled Probe Corrosion Rates
2/05/94 to 5/22/94

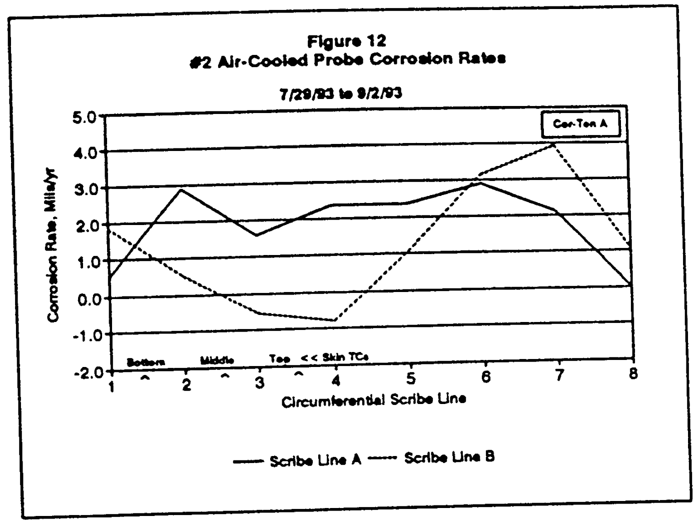


Figure 12
#2 Air-Cooled Probe Corrosion Rates
7/29/93 to 9/2/93

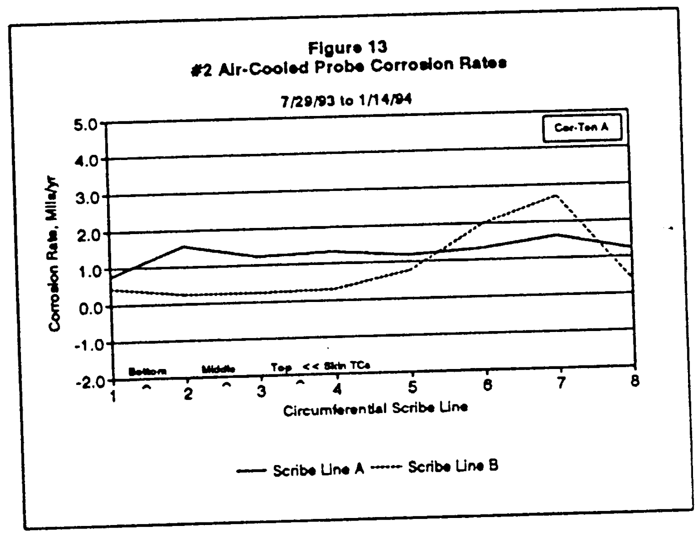


Figure 13
#2 Air-Cooled Probe Corrosion Rates
7/29/93 to 1/14/94

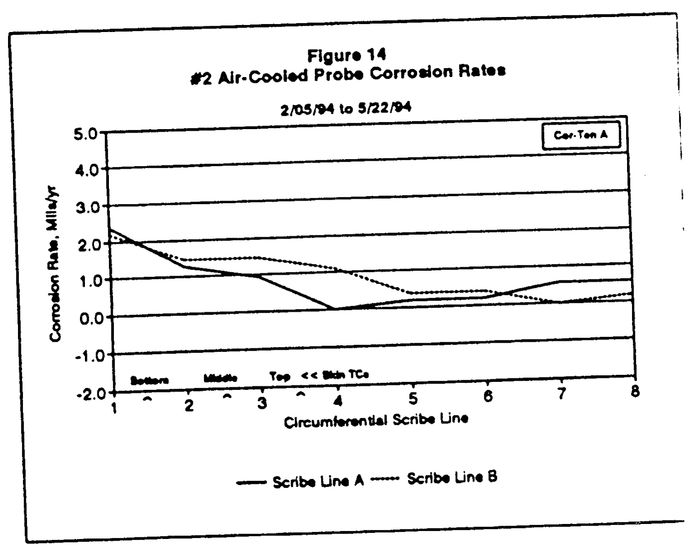


Figure 14
#2 Air-Cooled Probe Corrosion Rates
2/05/94 to 5/22/94

Figure 15
#3 Air-Cooled Probe Corrosion Rates
7/29/93 to 9/2/93

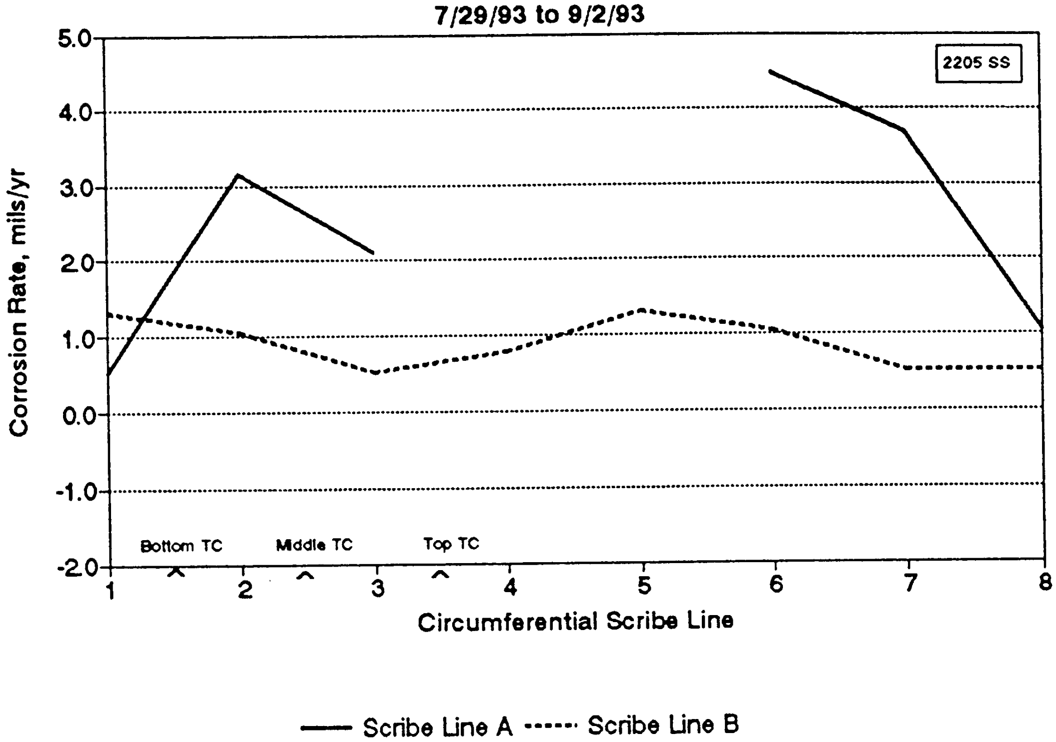
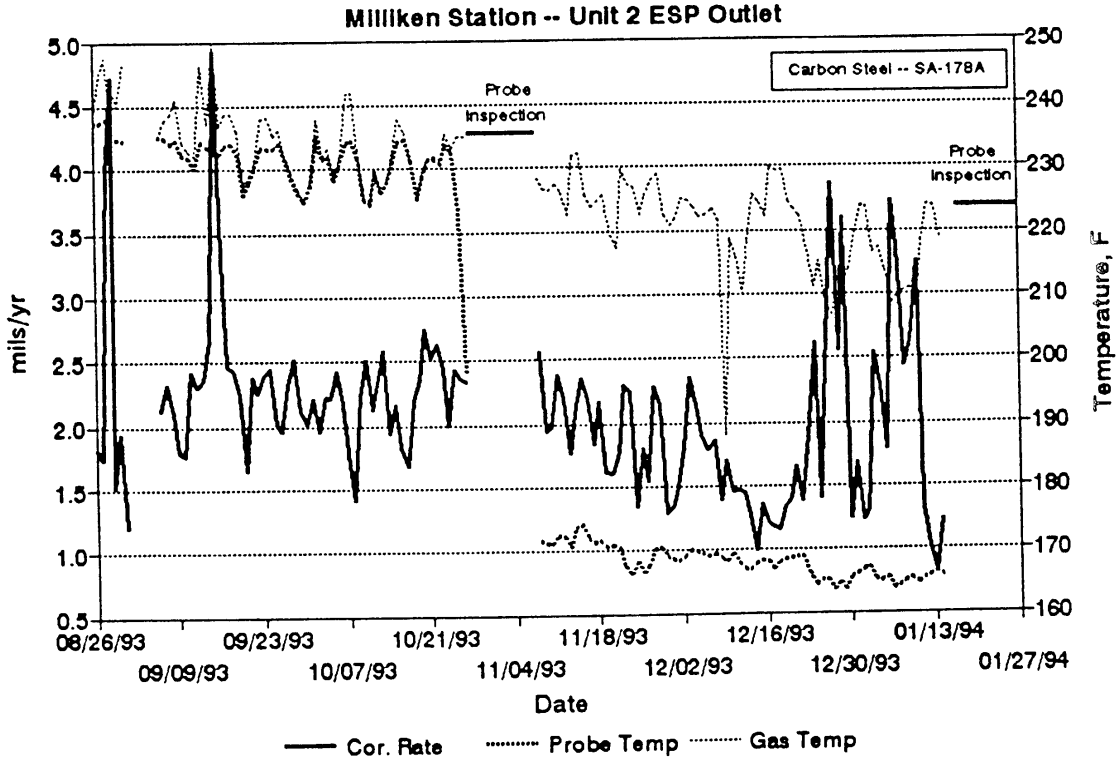


Figure 16
CAPCIS Probe Indicated Corrosion Rates
Milliken Station -- Unit 2 ESP Outlet



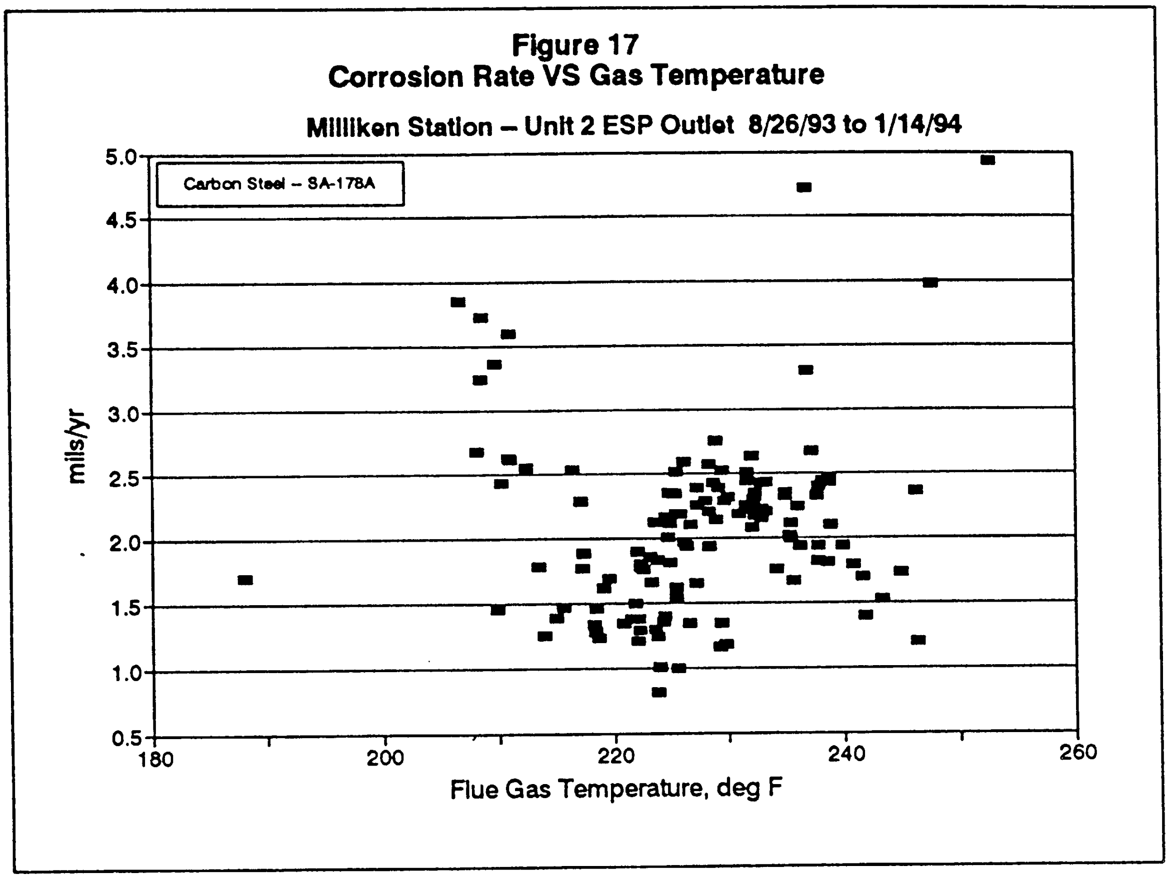


Figure 17
Corrosion Rate VS Gas Temperature
Milliken Station -- Unit 2 ESP Outlet 8/26/93 to 1/14/94
Carbon Steel -- SA-178A
mils/yr
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
180
200
220
240
260
Flue Gas Temperature, deg F

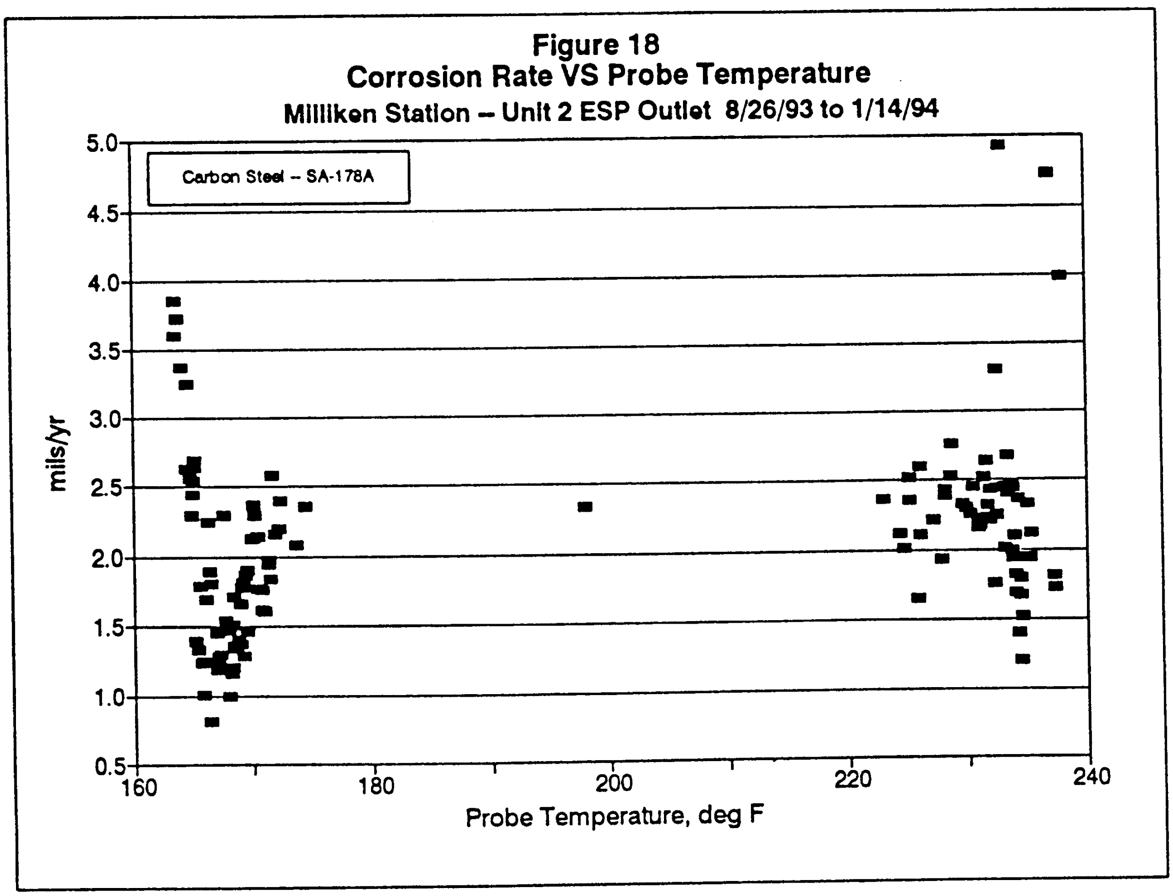


Figure 18
Corrosion Rate VS Probe Temperature
Milliken Station -- Unit 2 ESP Outlet 8/26/93 to 1/14/94
Carbon Steel -- SA-178A
mils/yr
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
160
180
200
220
240
Probe Temperature, deg F

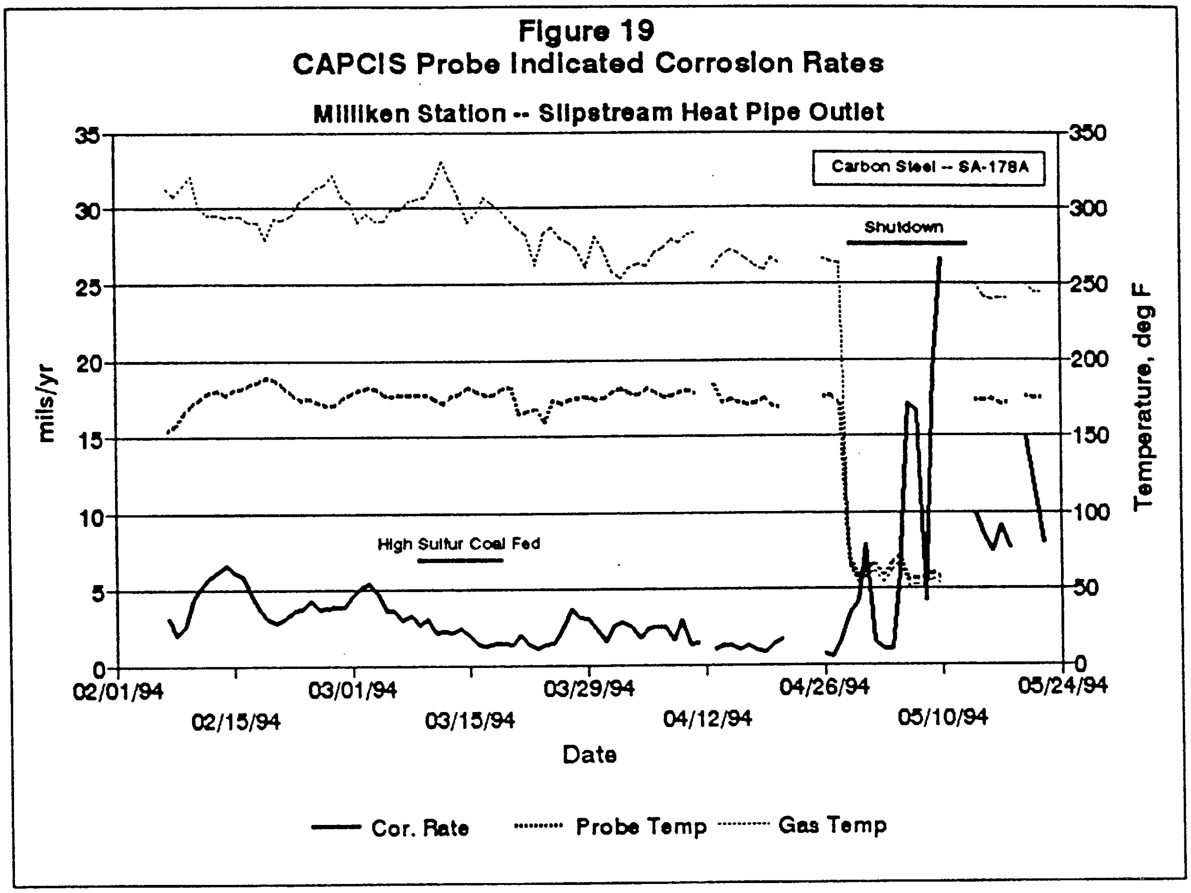


Figure 19
CAPCIS Probe Indicated Corrosion Rates
Milliken Station -- Slipstream Heat Pipe Outlet
Carbon Steel -- SA-178A
Shutdown
High Sulfur Coal Fed
mils/yr
Temperature, deg F
0
5
10
15
20
25
30
35
0
50
100
150
200
250
300
350
02/01/94
02/15/94
03/01/94
03/15/94
03/29/94
04/12/94
04/26/94
05/10/94
05/24/94
Date
Cor. Rate
Probe Temp
Gas Temp

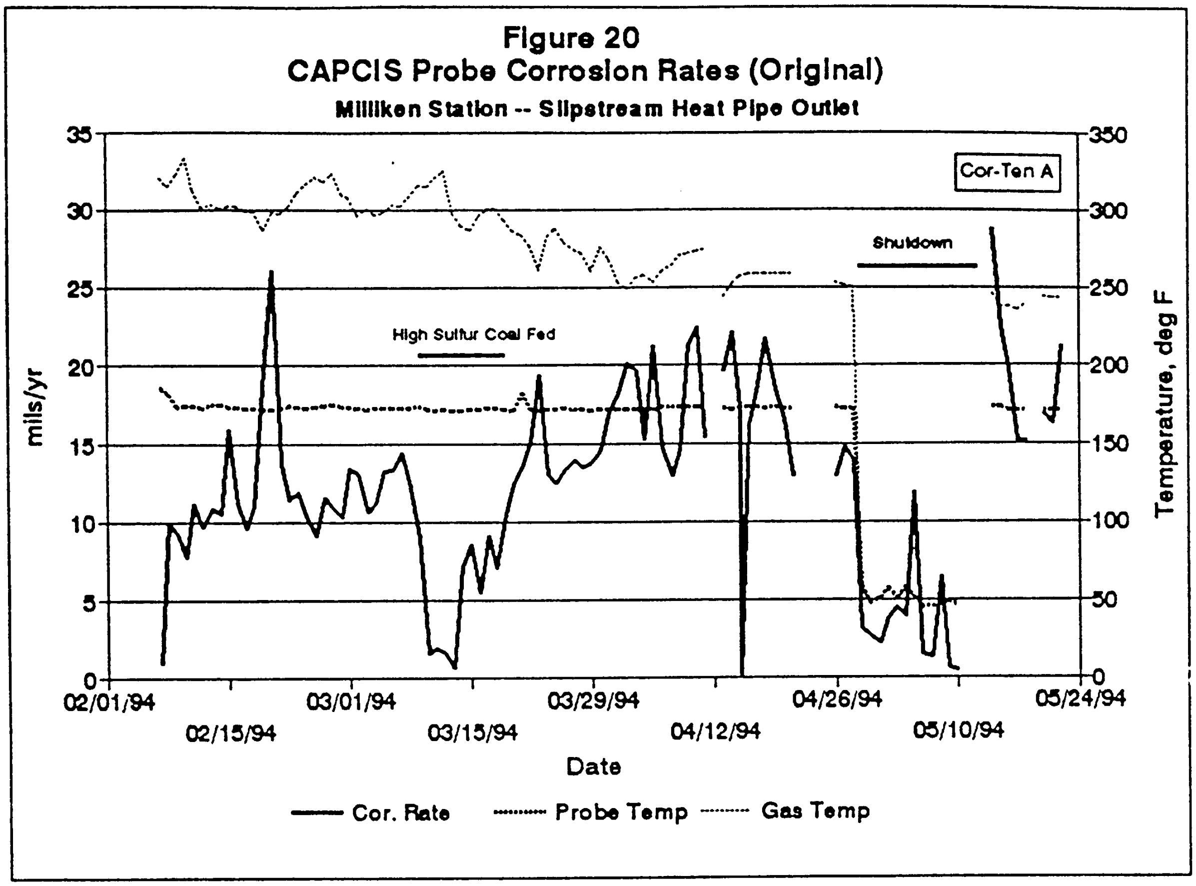


Figure 20
CAPCIS Probe Corrosion Rates (Original)
Milliken Station -- Slipstream Heat Pipe Outlet
Cor-Ten A
Shutdown
High Sulfur Coal Fed
mils/yr
Temperature, deg F
Date
02/01/94
02/15/94
03/01/94
03/15/94
03/29/94
04/12/94
04/26/94
05/10/94
05/24/94
Cor. Rate
Probe Temp
Gas Temp

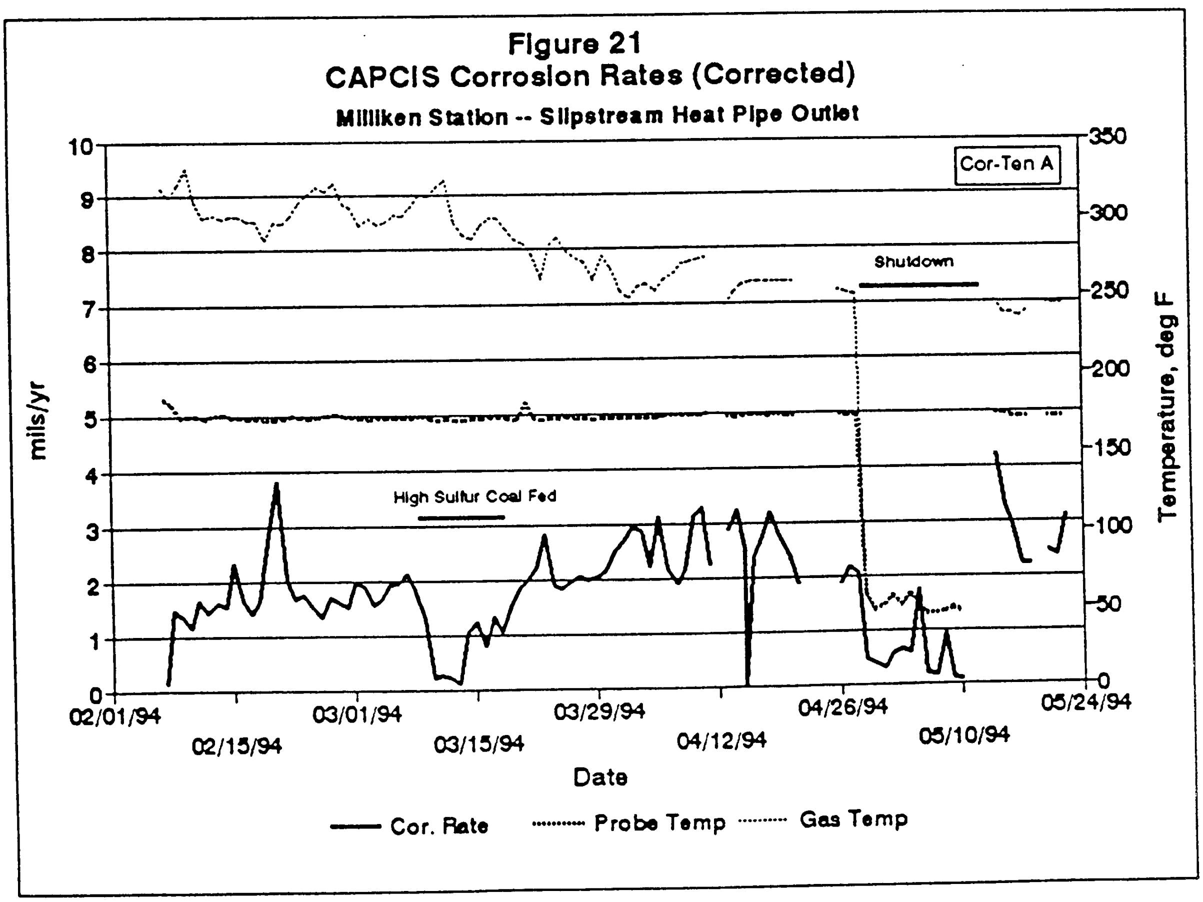


Figure 21
CAPCIS Corrosion Rates (Corrected)
Milliken Station -- Slipstream Heat Pipe Outlet
Cor-Ten A
Shutdown
High Sulfur Coal Fed
mils/yr
Temperature, deg F
Date
02/01/94
02/15/94
03/01/94
03/15/94
03/29/94
04/12/94
04/26/94
05/10/94
05/24/94
Cor. Rate
Probe Temp
Gas Temp

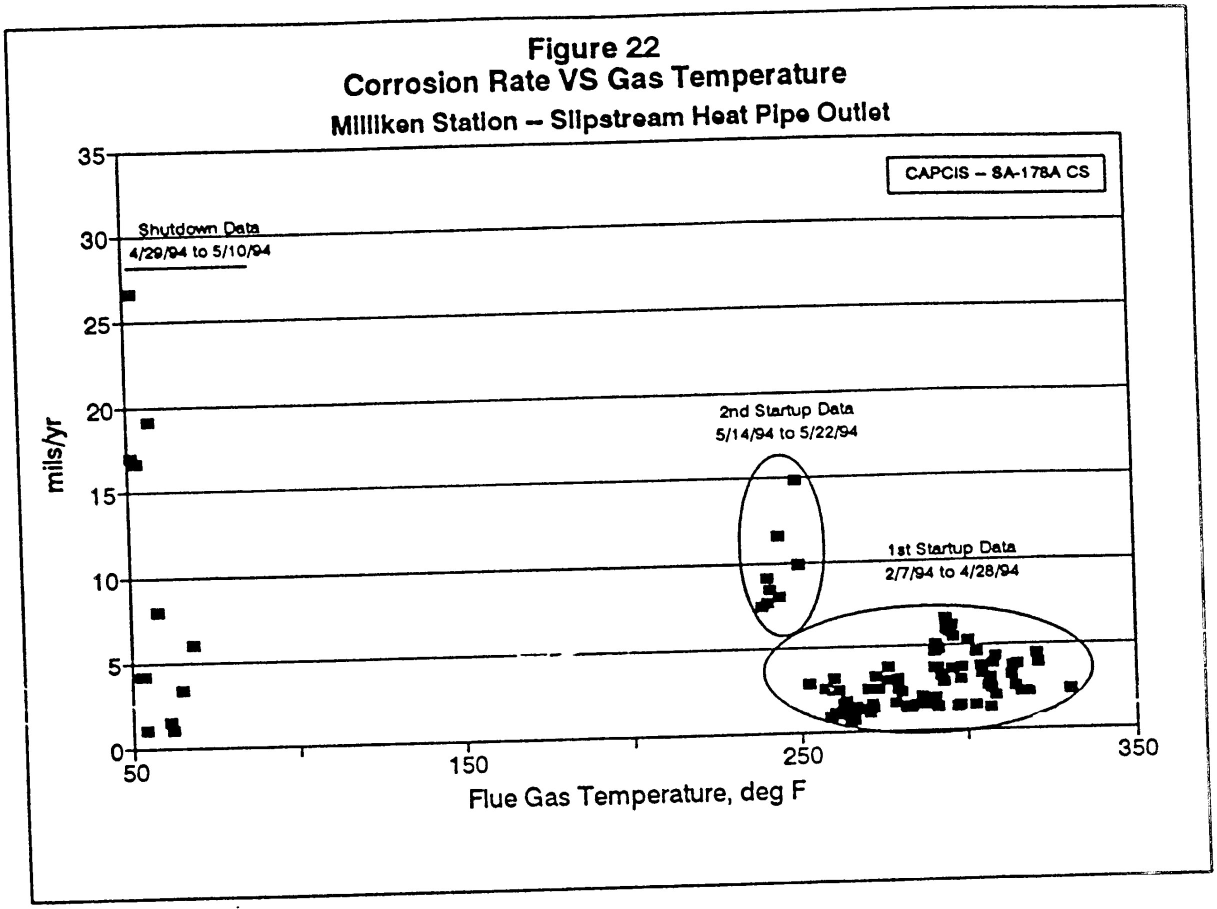


Figure 22
Corrosion Rate VS Gas Temperature
Milliken Station -- Slipstream Heat Pipe Outlet
CAPCIS -- SA-178A CS
Shutdown Data
4/29/94 to 5/10/94
2nd Startup Data
5/14/94 to 5/22/94
1st Startup Data
2/7/94 to 4/28/94
mils/yr
Flue Gas Temperature, deg F
0
5
10
15
20
25
30
35
50
150
250
350

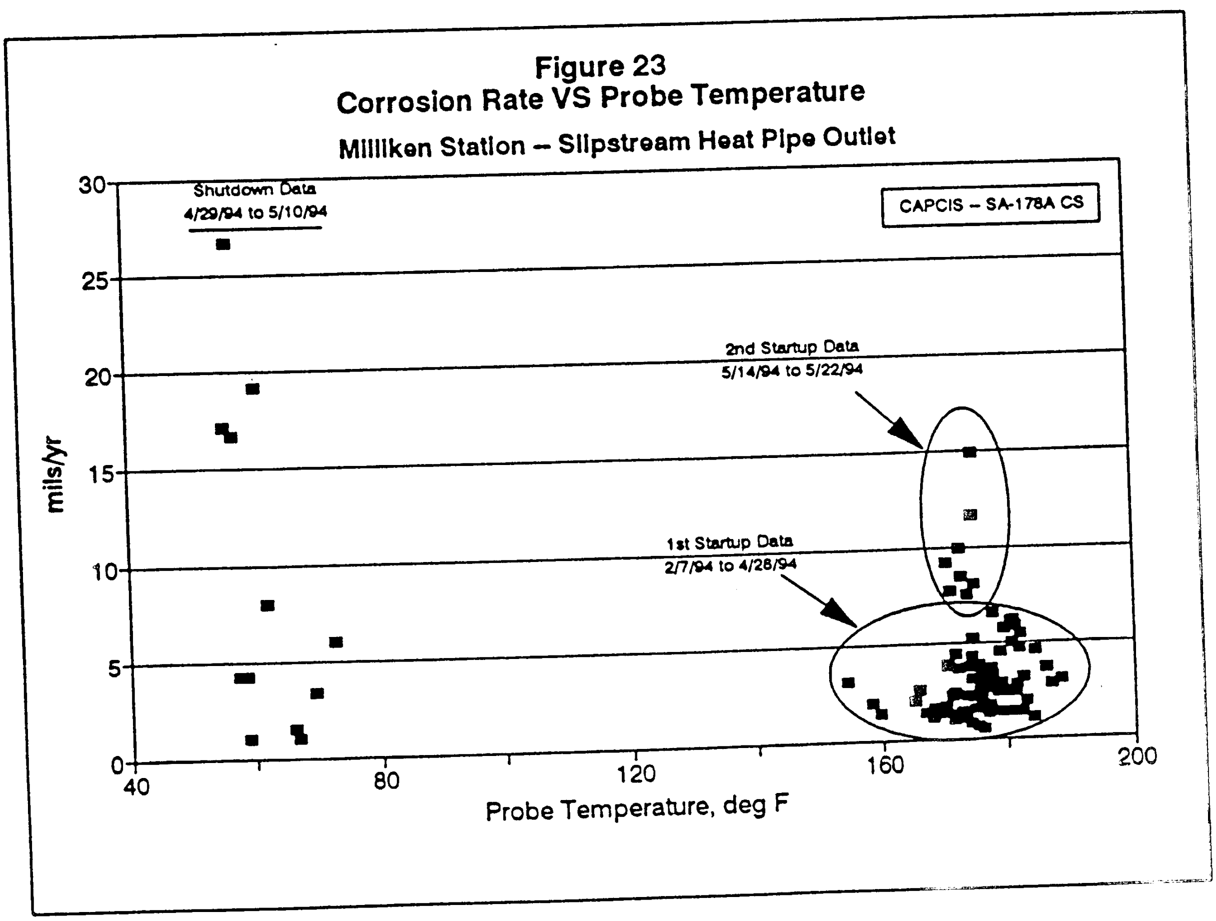


Figure 23
Corrosion Rate VS Probe Temperature
Milliken Station -- Slipstream Heat Pipe Outlet
CAPCIS -- SA-178A CS
Shutdown Data
4/29/94 to 5/10/94
2nd Startup Data
5/14/94 to 5/22/94
1st Startup Data
2/7/94 to 4/28/94
mils/yr
Probe Temperature, deg F
0
5
10
15
20
25
30
40
80
120
160
200

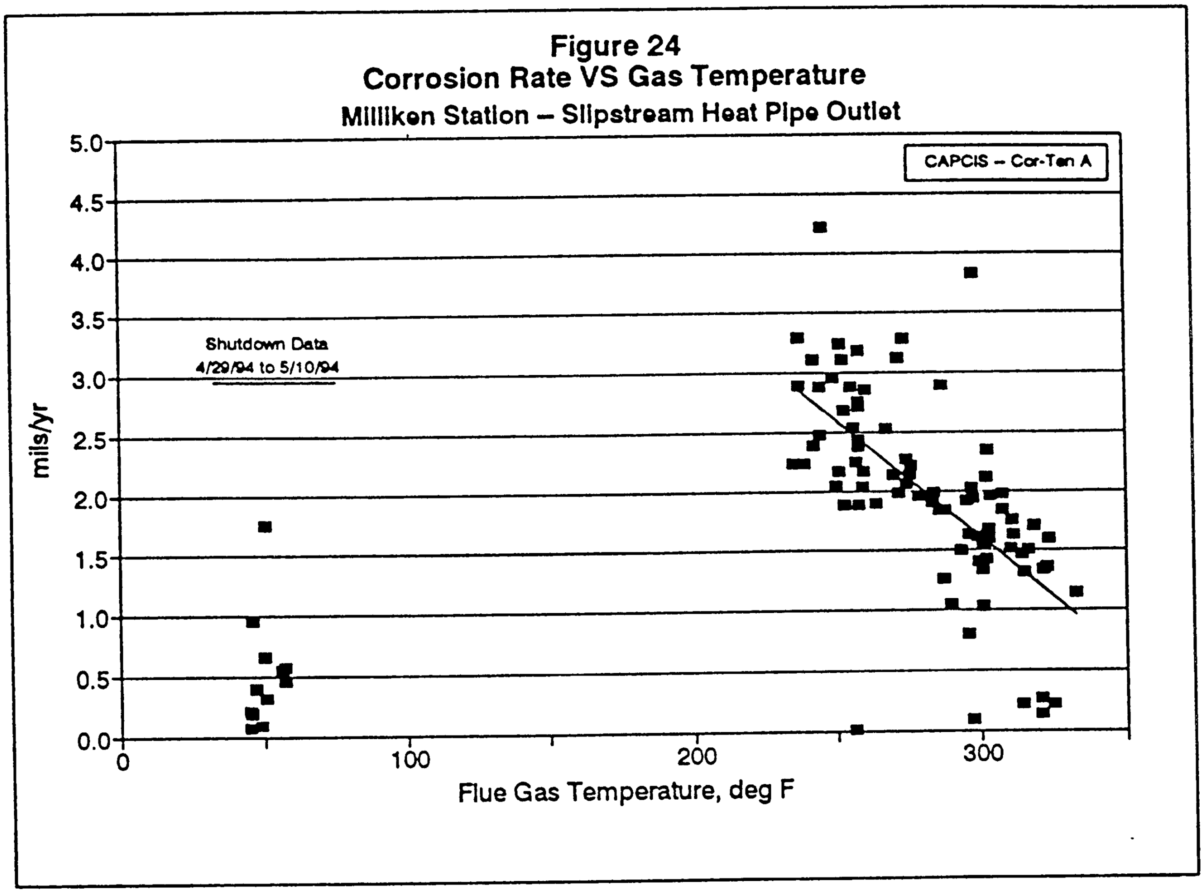


Figure 24
Corrosion Rate VS Gas Temperature
Milliken Station -- Slipstream Heat Pipe Outlet
CAPCIS -- Cor-Ten A
Shutdown Data
4/29/94 to 5/10/94
mils/yr
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
0
100
200
300
Flue Gas Temperature, deg F

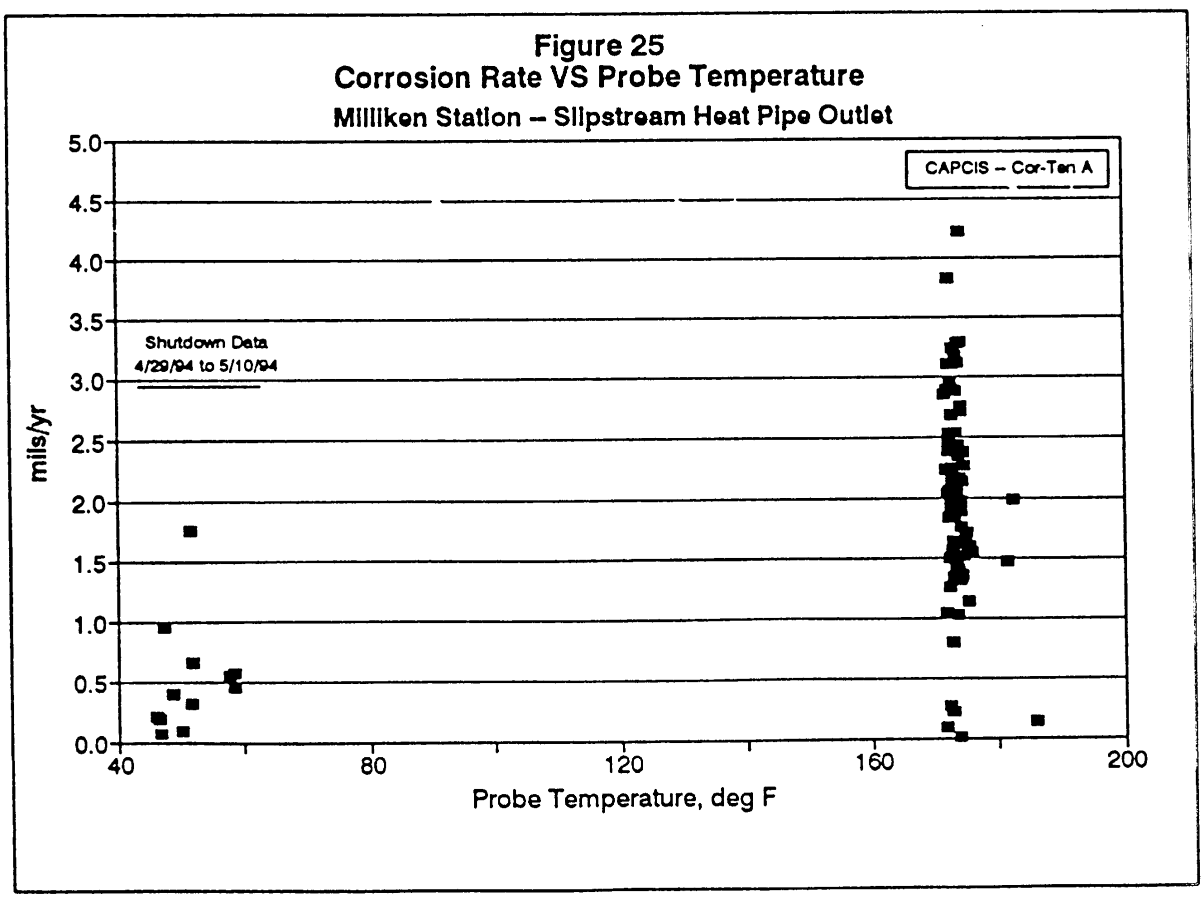


Figure 25
Corrosion Rate VS Probe Temperature
Milliken Station -- Slipstream Heat Pipe Outlet
CAPCIS -- Cor-Ten A
Shutdown Data
4/29/94 to 5/10/94
mils/yr
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
40
80
120
160
200
Probe Temperature, deg F

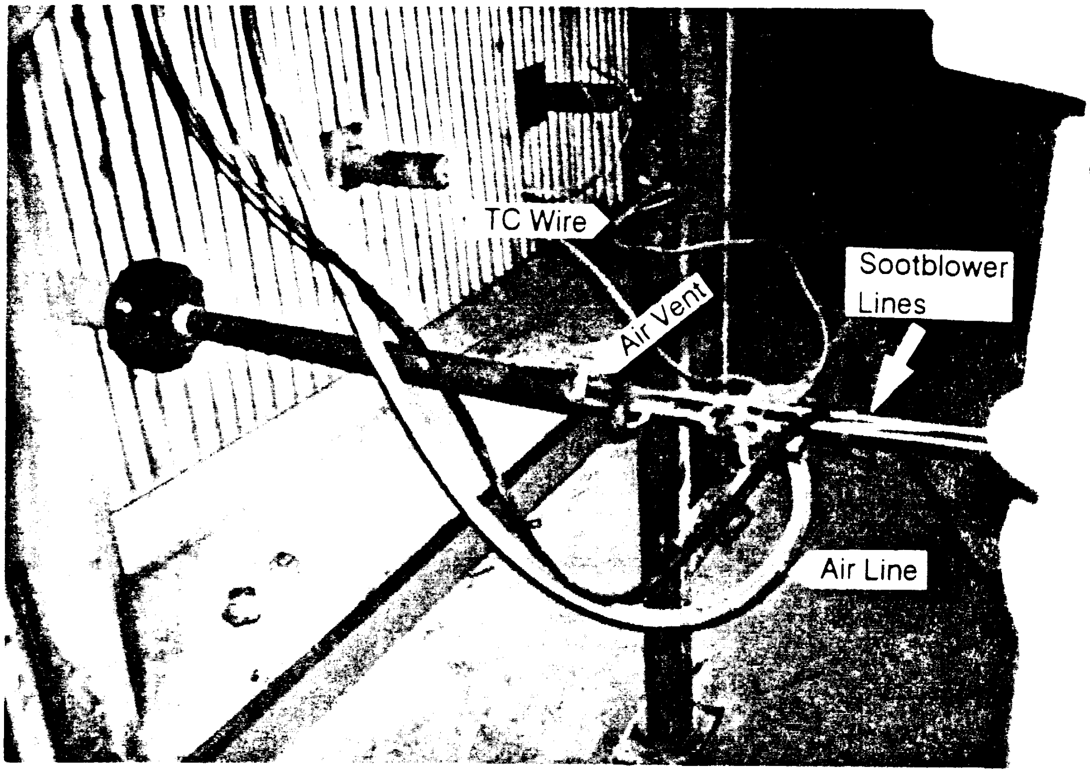


Figure 28. Typical installation for air-cooled corrosion probes.

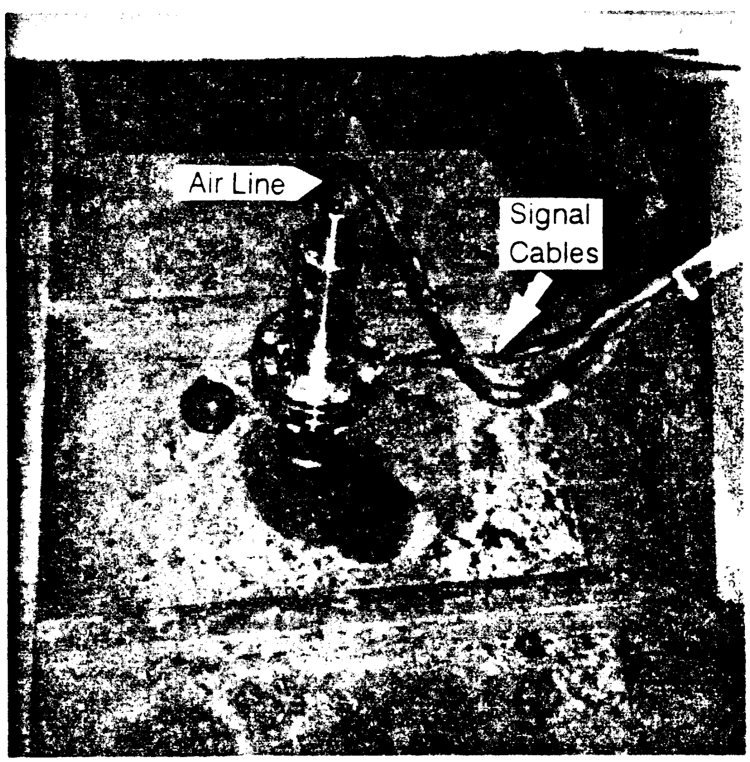


Figure 29. Typical installation of CAPCIS corrosion monitoring probes. Location at ESP outlet.

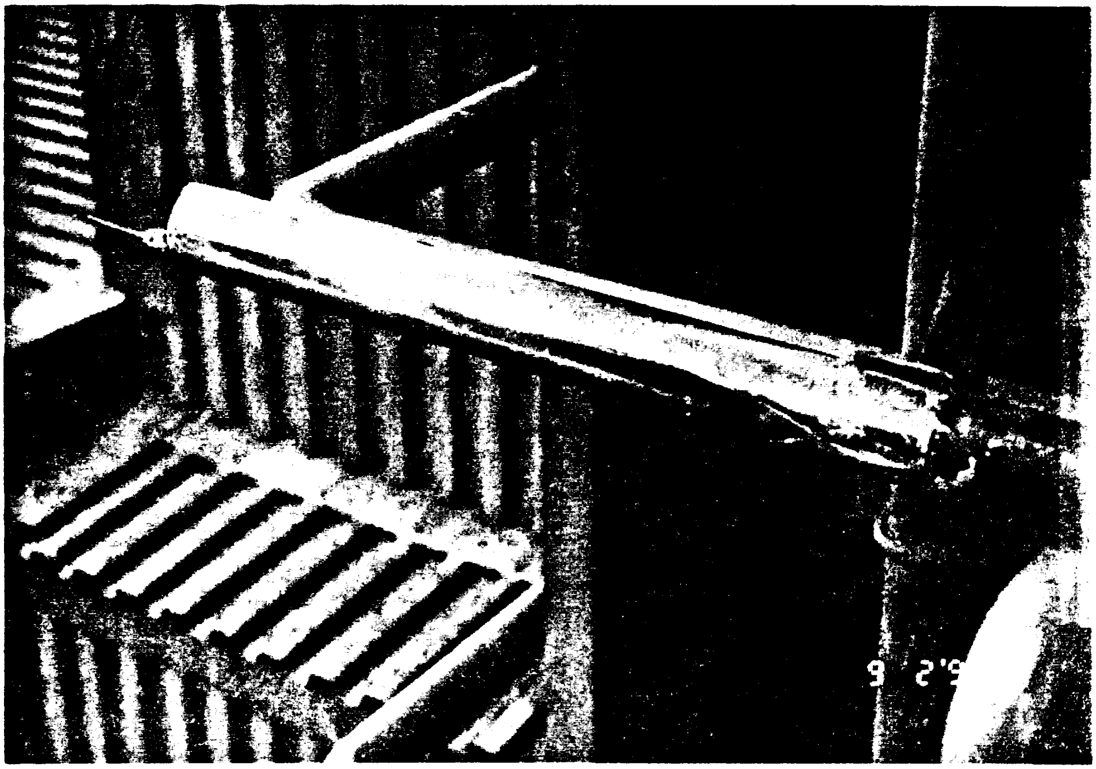


Figure 30. Condition of No. 1 air-cooled, Cor-Ten A corrosion probe after 1168 hours in operation. Surface deposits were bone dry when probe was removed from system.

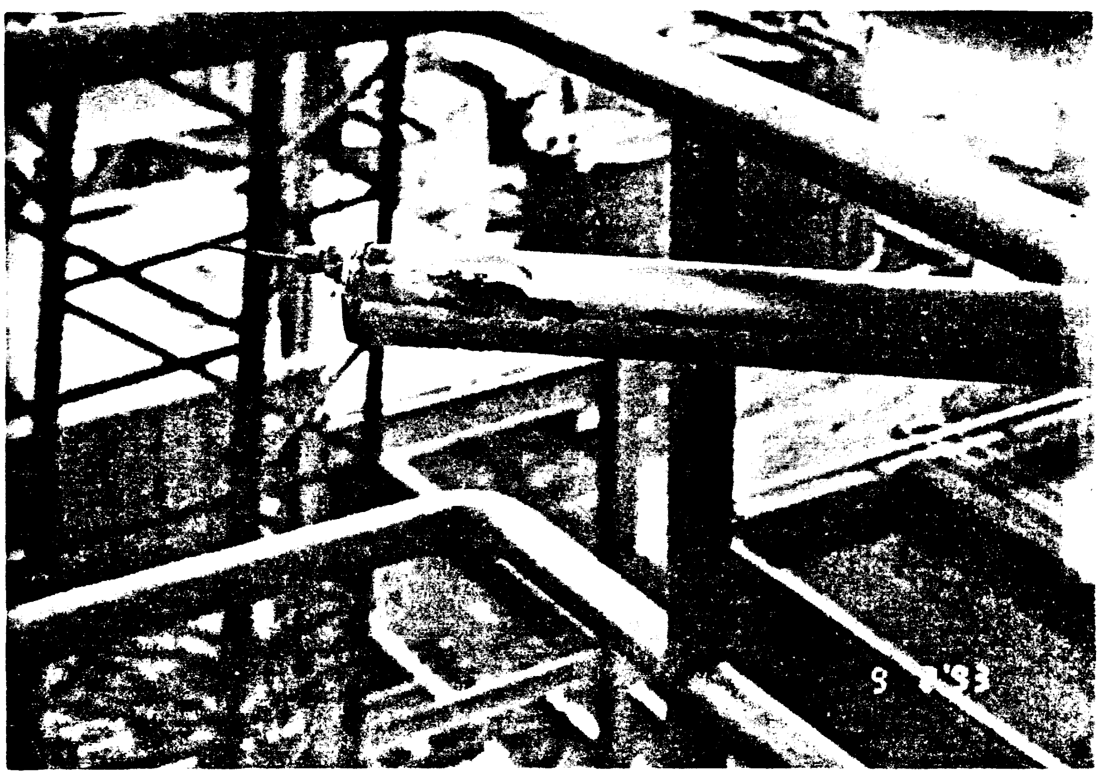


Figure 31. Condition of No. 2 air-cooled, Cor-Ten A corrosion probe after 832 hours in operation. Surface deposits were bone dry when probe was removed from system.

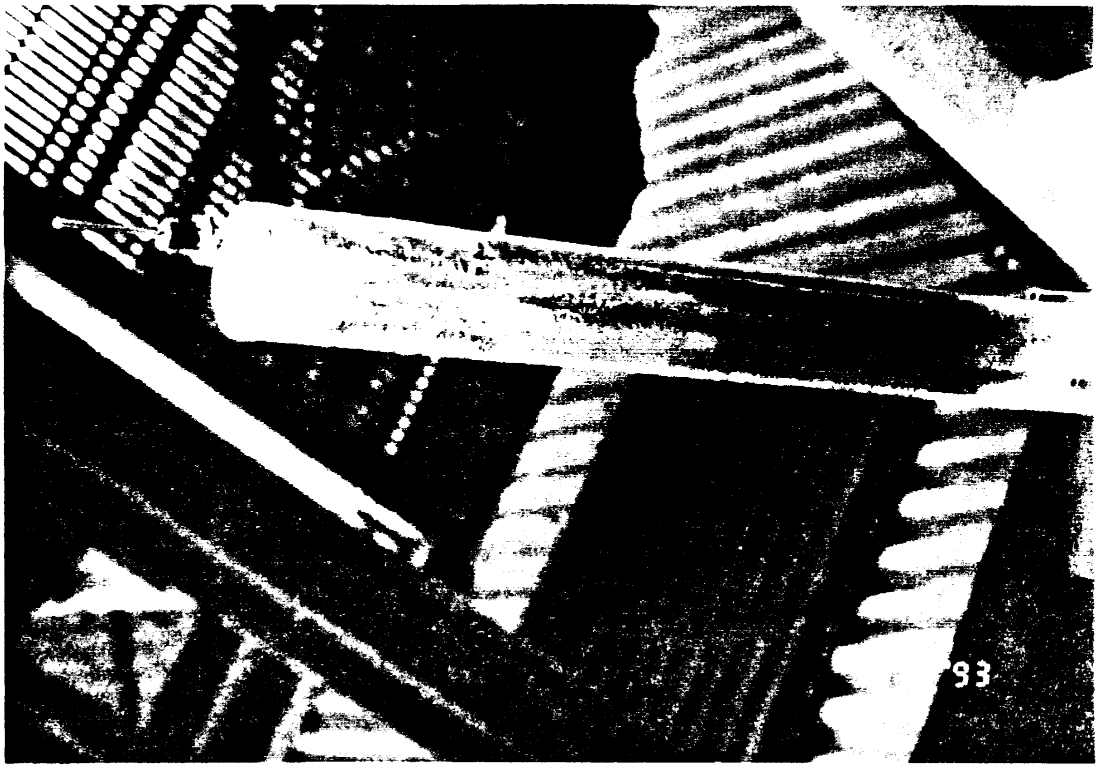


Figure 32. Condition of No. 3 air-cooled, 2205 SS corrosion probe after 832 hours in operation. Like for the Nos. 1 and 2 air-cooled probes, the surface deposits were bone dry when probe was removed from system.

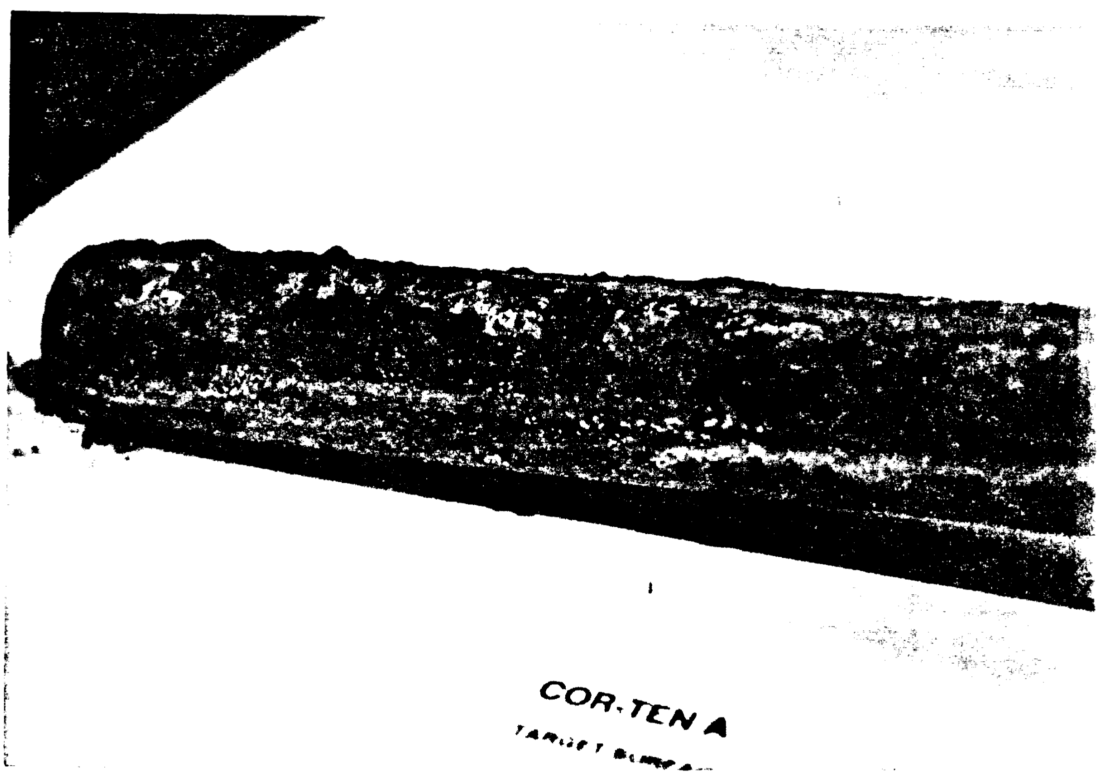


Figure 33. View of cold-end tip of No. 1 air-cooled, Cor-Ten A corrosion probe (1168 hours in operation) after removal from system and one day exposure to humid air. Note spalling damp deposits.

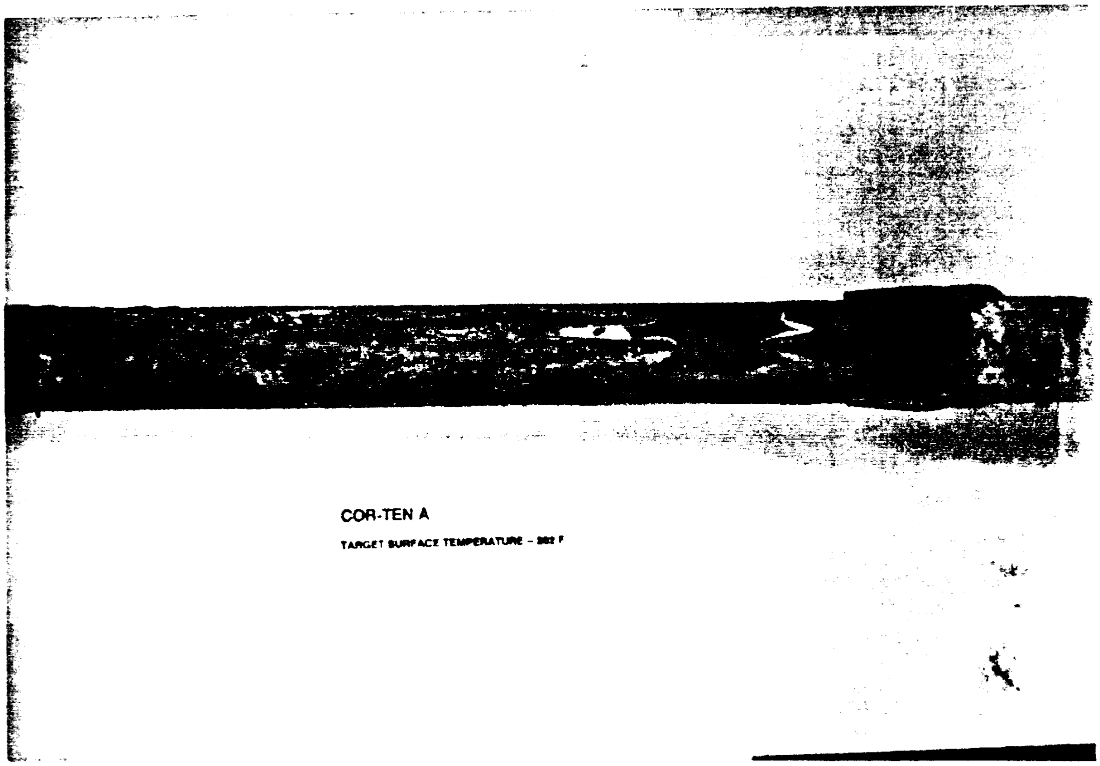


Figure 34. Overall, windward side view of No. 2 air-cooled, Cor-Ten A corrosion probe (832 hours in operation) after removal from system and one day exposure to humid air. Solids are damp.

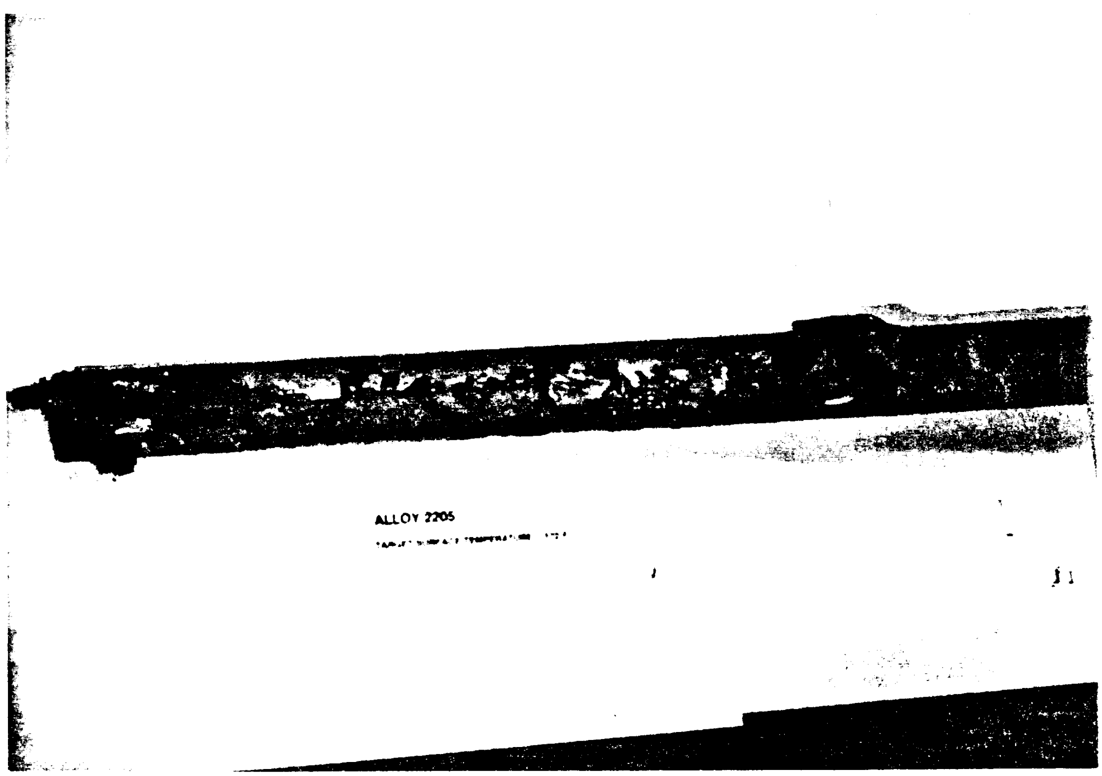


Figure 35. Overall view of No.3 air-cooled, 2205 SS corrosion probe (832 hours in operation) after removal from system and one day exposure to humid air. Solids were damp to wet and surface was partially coated with an oily liquid.

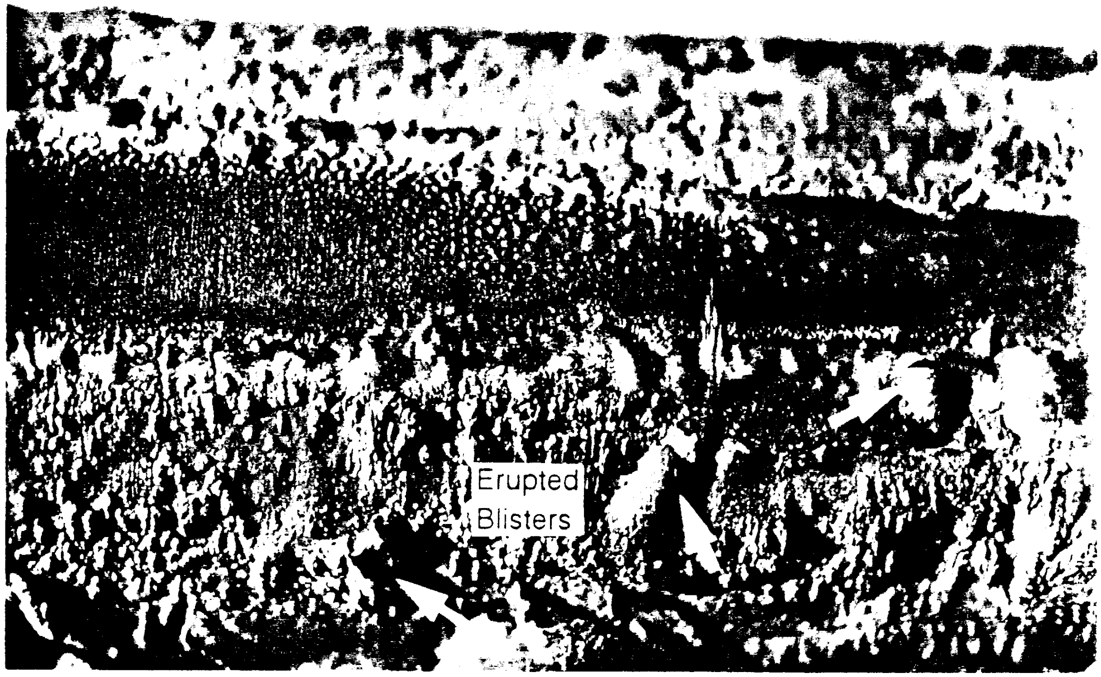


Figure 36. Close-up of spalling damp deposits on No. 1 air-cooled probe shown in Figure 33. Note deposit blisters which formed when surface became damp.

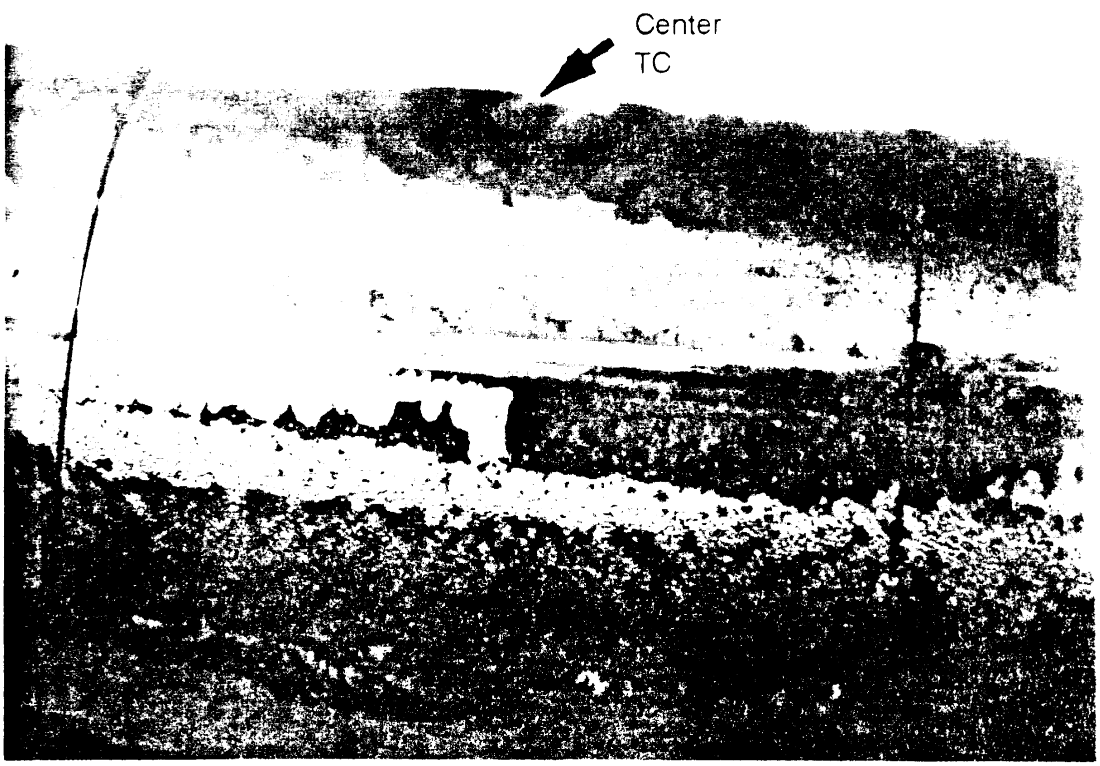


Figure 37. Close-up of 2" long scribe line demarcated section which contains center skin thermocouple for No. 3 air-cooled, 2205 SS corrosion probe. Note surface pitting in areas normally covered by deposits.

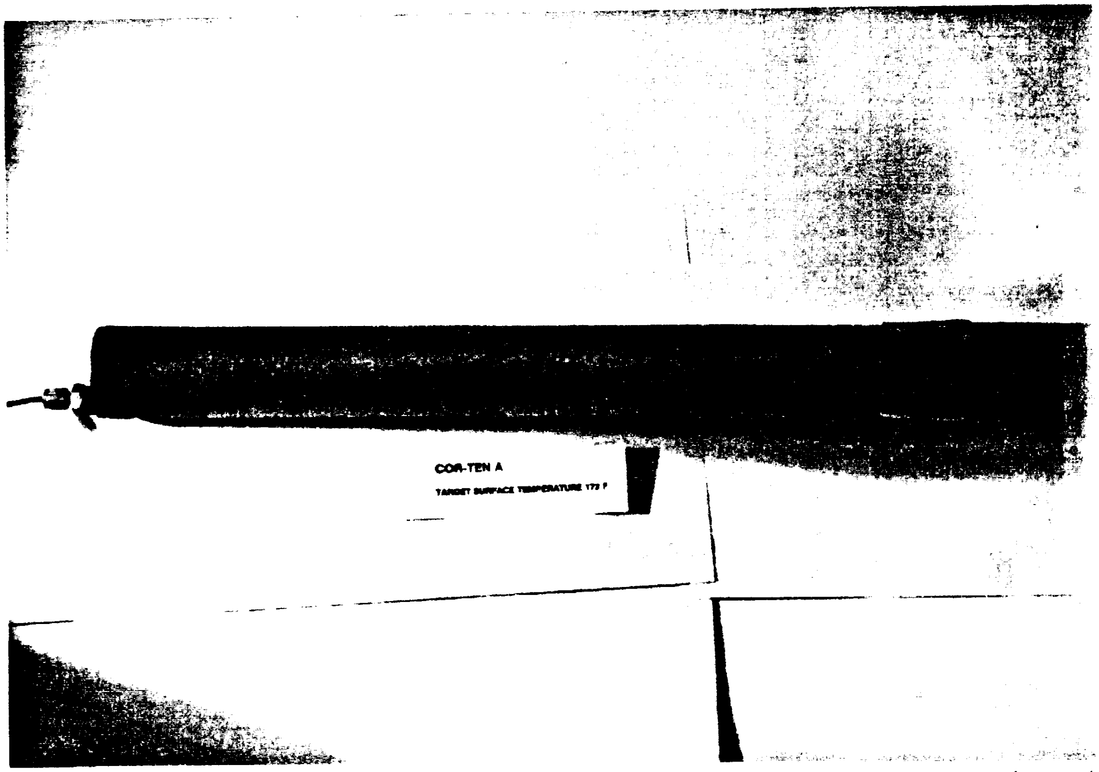


Figure 38. Overall view of cleaned No. 1 air-cooled, Cor-Ten A corrosion probe (1168 hours in service).

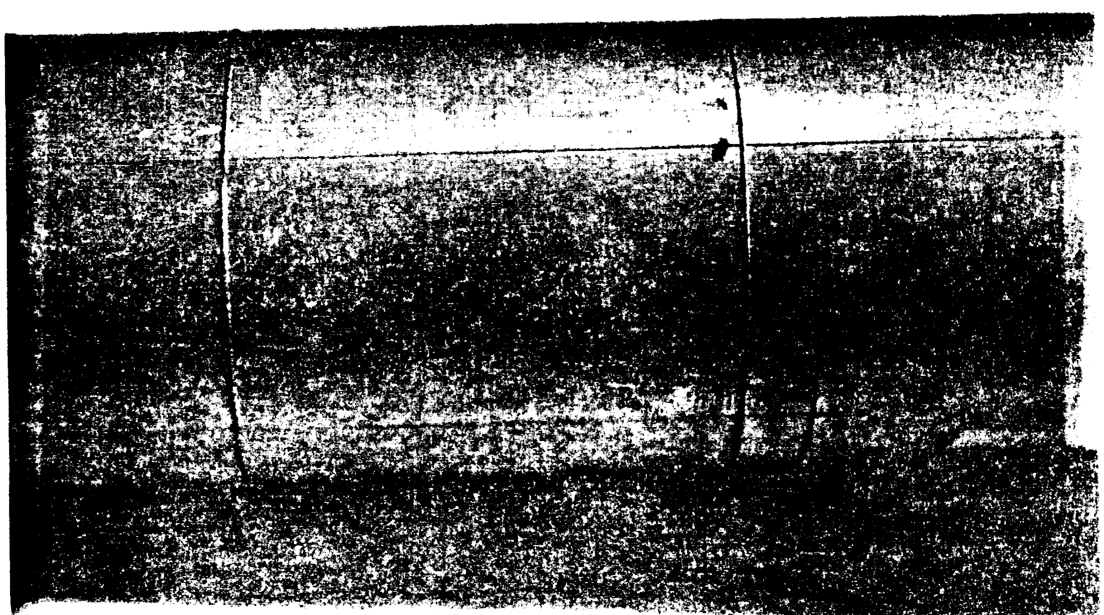


Figure 39. Close-up view of cleaned No. 1 air-cooled, Cor-Ten A probe (1168 hours in service). View shows surface condition of 3rd 2" long, scribe line demarcated section which contained the middle skin thermocouple. Coarse machining marks are clearly visible.

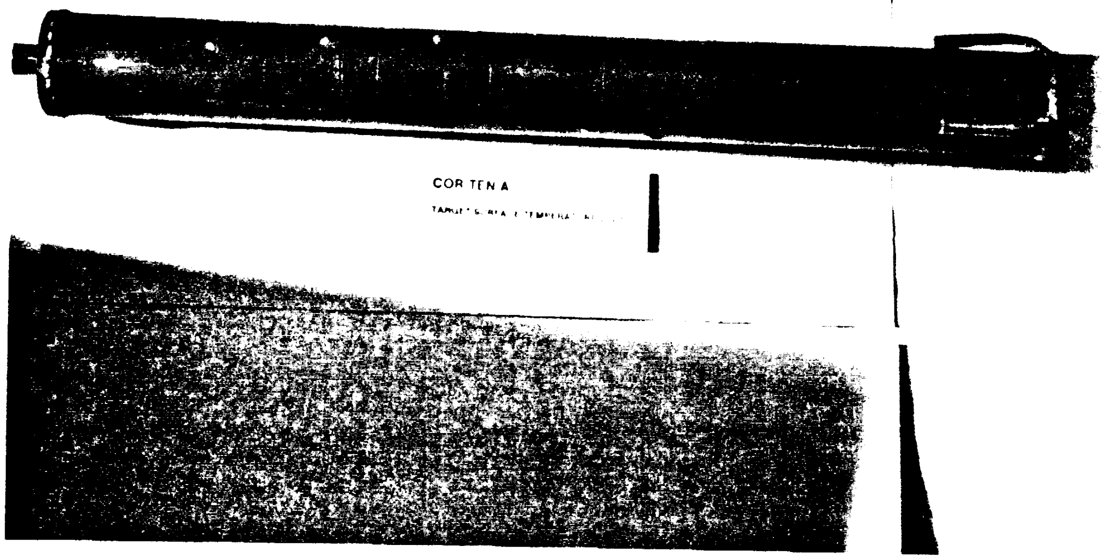


Figure 40. Overall view of cleaned No. 2 air-cooled, Cor-Ten A corrosion probe (832 hours in service).

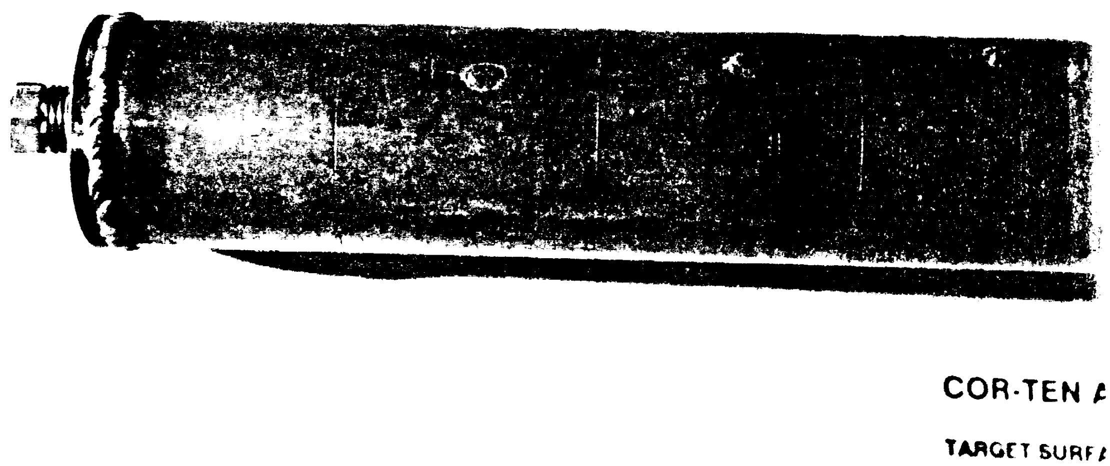


Figure 41. Cold-end close-up view of No. 2 air-cooled, Cor-Ten A corrosion probe (832 hours in service). Finely machined surface is still smooth with minor discoloration at the tip (coldest area of probe).

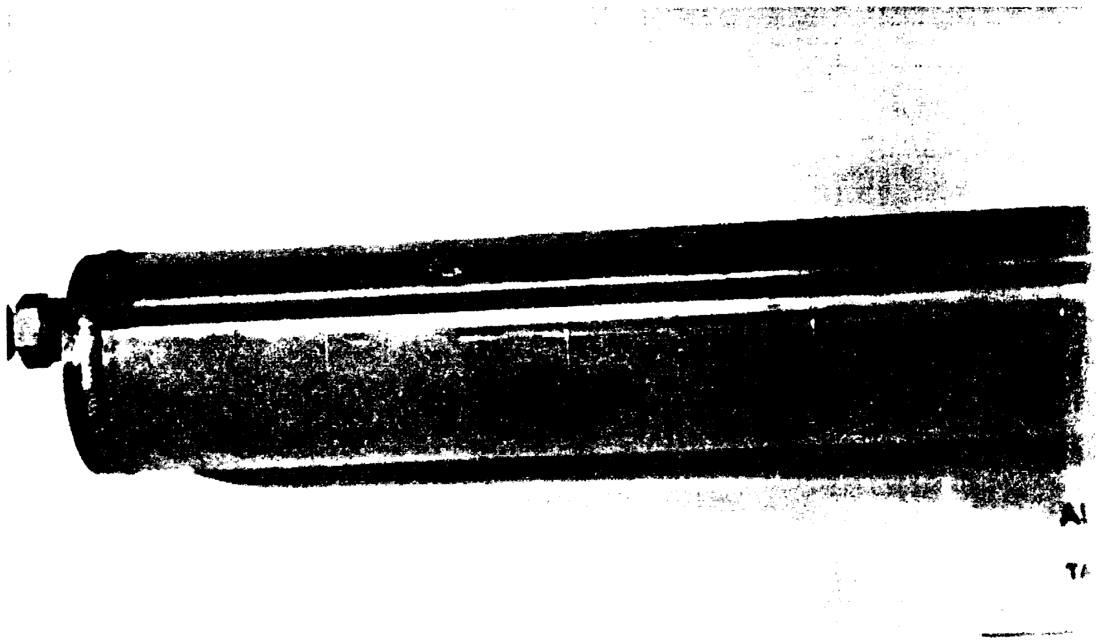


Figure 42. Close-up of cold-end tip of cleaned No. 3 air-cooled, 2205 SS corrosion probe (832 hours in service). Areas which were covered by deposits are dull and pitted.

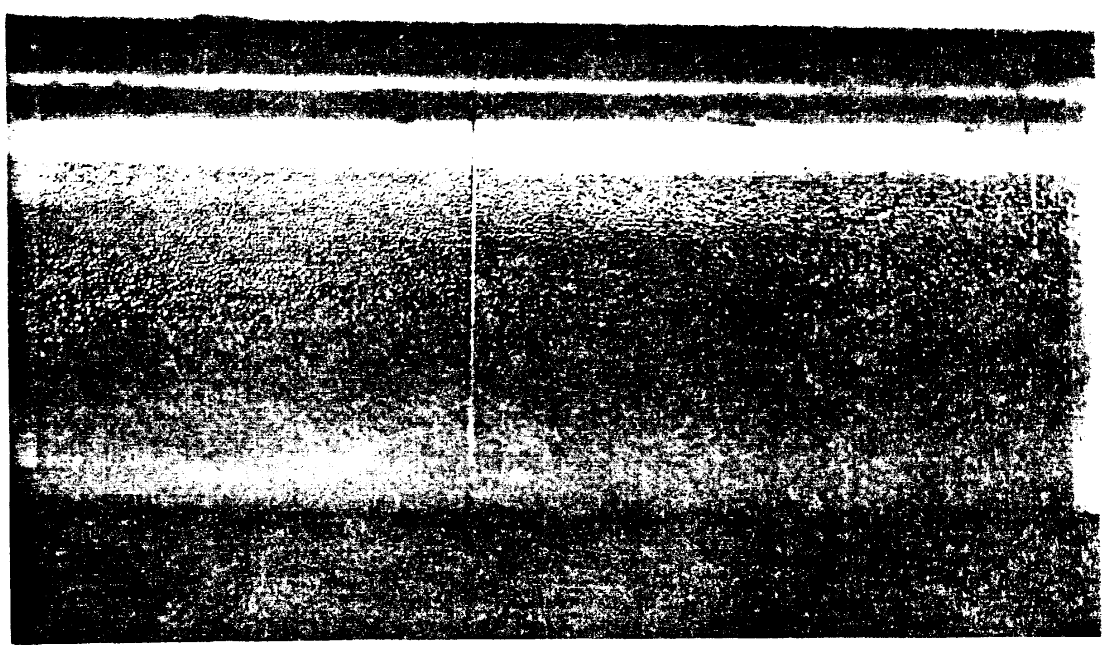


Figure 43. Close-up view of probe shown in Figure 42 between 2" division scribe lines which bracket the middle and top skin thermocouples. Note heavy pitting of surfaces which were covered by deposits.

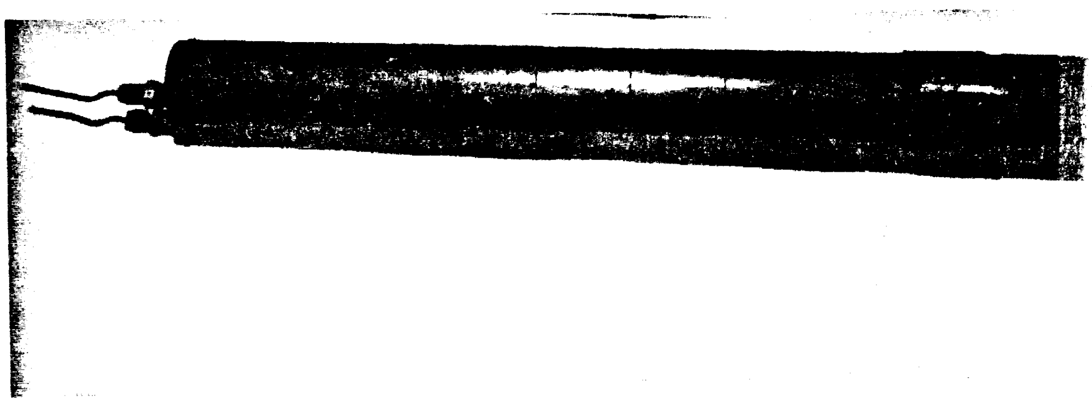


Figure 44. End-of-test overall view of cleaned No. 1 air-cooled, Cor-Ten A corrosion probe (3832 hours at 172°F and 2474 hours at 192°F).

Figure 45. Close-up of cold-end of probe shown in Figure 44. Note presence of machine marks and lack of corrosion.

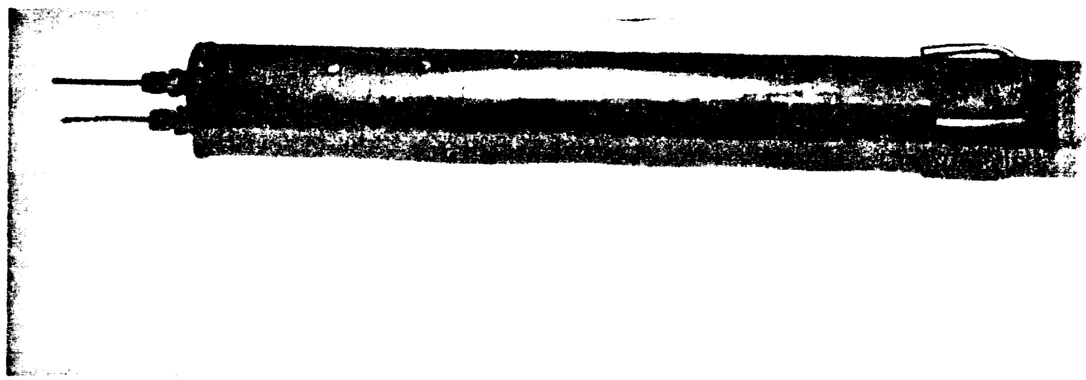


Figure 46. End-of-test overall view of cleaned No. 2 air-cooled Cor-Ten A corrosion probe (3496 hours at 201°F and 2378 hours at 174°F).

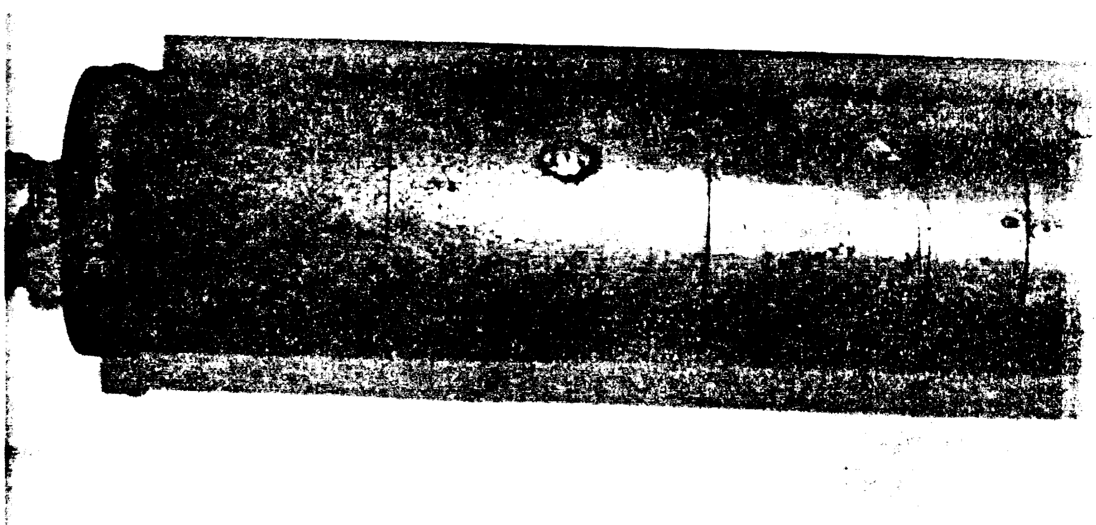


Figure 47. Close-up of cold-end of probe shown in Figure 46. Note surface roughness at cold-end tip (compare with Figure 45).

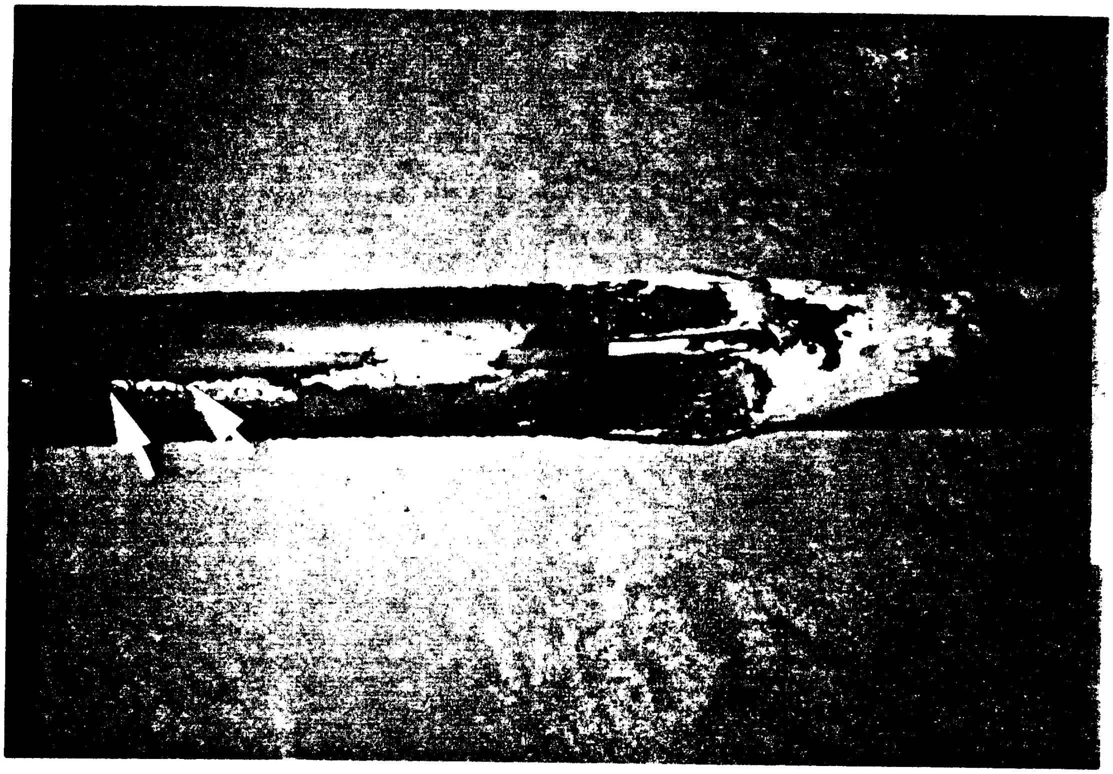


Figure 48. Top end view of No. 2 air-cooled, Cor-Ten A corrosion probe with 2664 hours at 201°F in operation between cleanings. View shows clean and deposit covered areas.

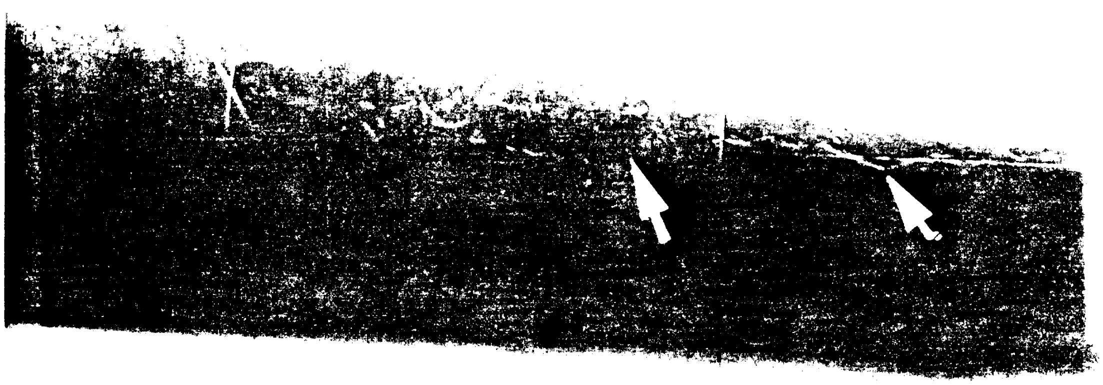


Figure 49. Close-up of corrosion probe area noted in Figure 48. Metal loss has occurred at interface between deposit covered area and deposit free areas.

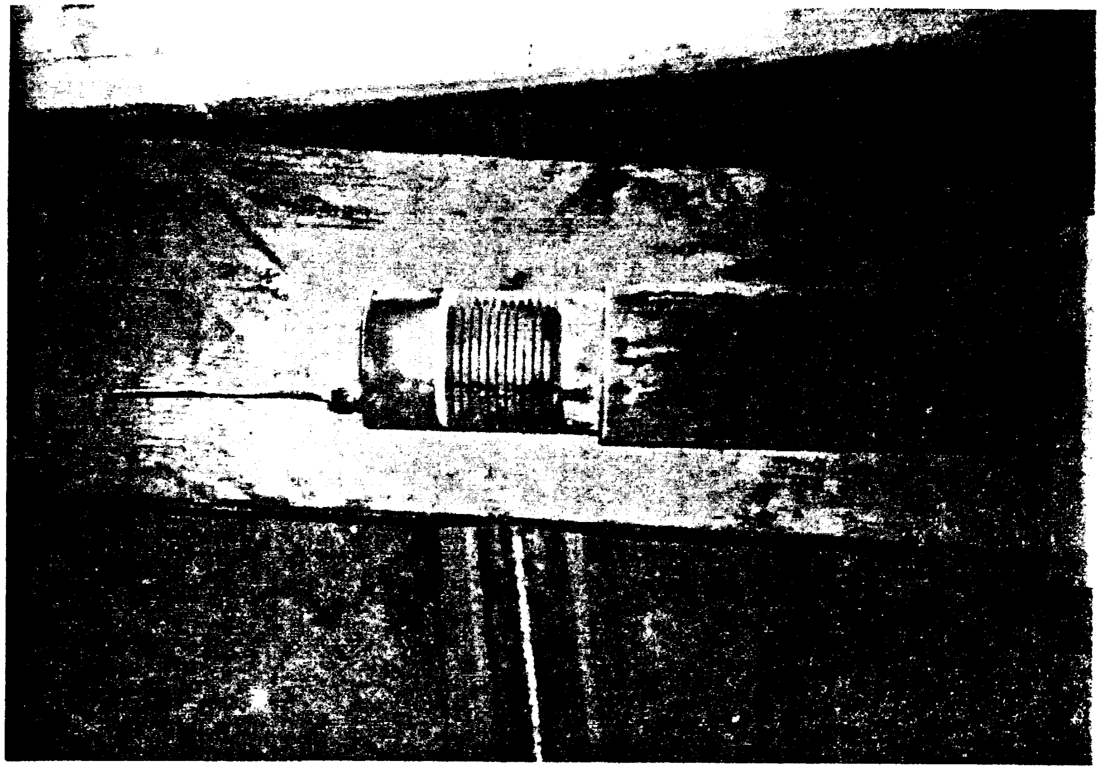


Figure 50. Condition of SA-178A CAPCIS corrosion probe at end of ESP test period (1609 hours in service since last cleaning).

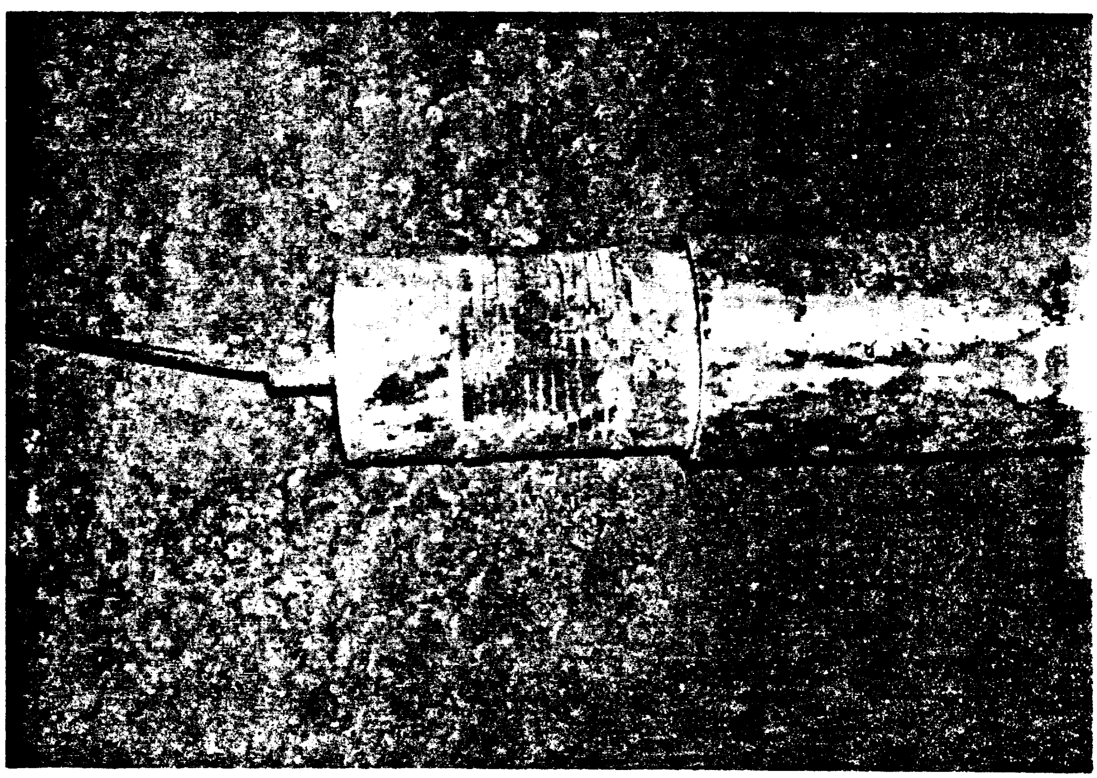


Figure 51. Condition of SA-178A CAPCIS corrosion probe at end of slipstream heat pipe tests (2487 hours in service at 176°F).

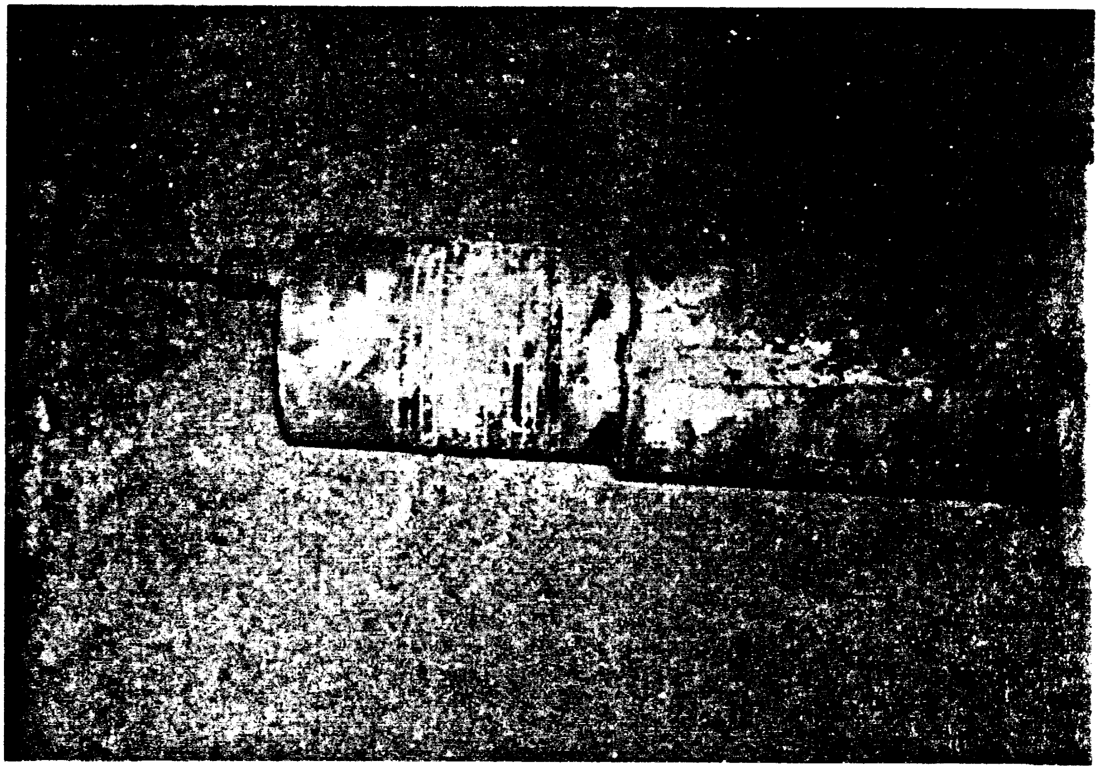
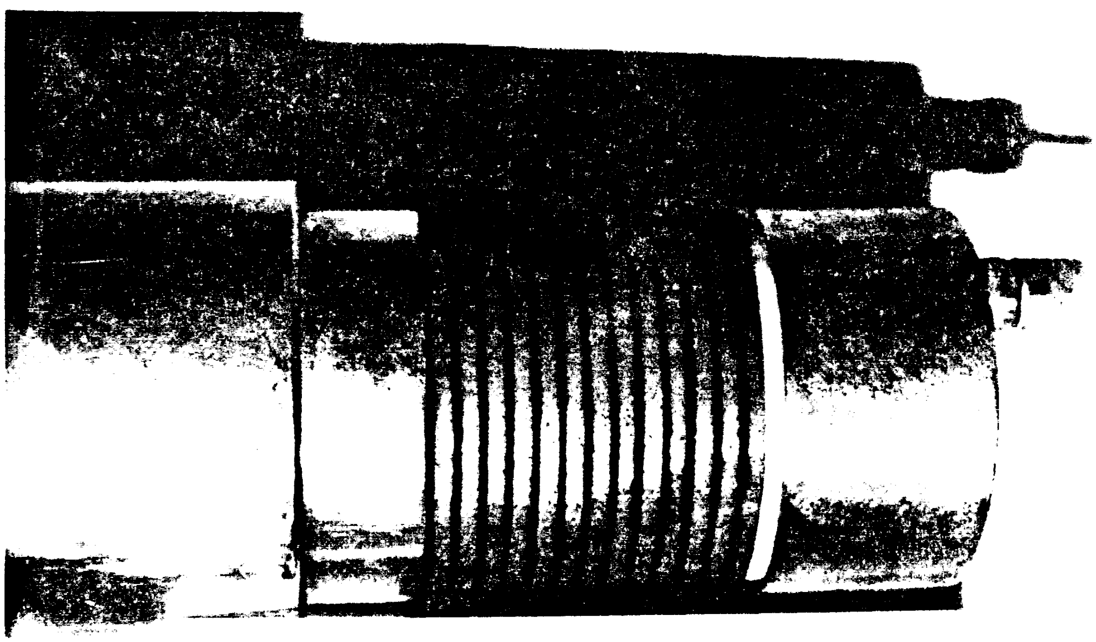


Figure 52. Condition of Cor-Ten A CAPCIS corrosion probe at end of slipstream heat pipe tests (2487 hours in service at 174°F).



SA-178A CAPCIS Probe

Figure 53. Close-up, final condition of cleaned SA-178A CAPCIS corrosion probe sensing elements (2487 hours in service at slipstream heat pipe outlet). Black marks on probe are ink marks used by technician to note which elements had been measured.

Cor-Ten A CAPCIS Probe

Figure 54. Close-up, final condition of cleaned Cor-Ten A CAPCIS corrosion probe sensing elements (2487 hours in service at slipstream heat pipe outlet). Sensing elements surfaces appear smoother than those of the SA-178A probe.

APPENDIX

Table 1A
Air-Cooled Probe Measurements And Corrosion Rates
Milliken Station -- 7/15/93 to 9/2/93

Probe	1	
Material	Cor-Ten A Operated at 172 F	
Location	Unit 2 Air Htr Outlet Duct	
Date - Time	07/15/93 (Installed)	09/02/93 (removed)
Operating Hours	0	1168
Meas Temp, F	70	70

	Initial Diameter inches		Final Diameter inches		Diameter Change inches		Corrosion Rate mils/yr	
Axial Score Line>	A	B	A	B	A	B	A	B
Ring Score #								
Bottom 1	1.8595	1.8501	1.8588	1.8501	0.0007	0.0000	2.6	0.0
2(1)	1.8574	1.8530	1.8572	1.8533	0.0002	-0.0003	0.7	-1.1
3(1)	1.8552	1.8561	1.8549	1.8559	0.0003	0.0002	1.1	0.7
4	1.8539	1.8559	1.8537	1.8557	0.0002	0.0002	0.8	0.8
5	1.8554	1.8522	1.8551	1.8522	0.0003	0.0000	1.1	0.0
6	1.8568	1.8509	1.8565	1.8510	0.0003	-0.0001	1.1	-0.4
7	1.8530	1.8494	1.8529	1.8496	0.0001	-0.0002	0.4	-0.7
Top 8	1.8479	1.8483	1.8476	1.8482	0.0003	0.0001	1.1	0.4
						AVG	1.1	-0.0
						SDEV	0.7	0.7

Probe	2	
Material	Cor-Ten A Operated At 202 F	
Location	Unit 2 Air Htr Outlet Duct	
Date	07/29/93 (Installed)	09/02/93 (removed)
Operating Hours	0	832
Meas Temp, F	70	70

	Initial Diameter, Inches				Measured Difference mils		Avg Initial Diameter inches		Final Diameter inches		Diameter Change inches		Corrosion Rate mils/yr	
Axial Score Line>	A	A(2)	B	B(2)	A	B	A	B	A	B	A	B	A	B
Ring Score #														
Bottom 1	1.8461	1.8461	1.8496	1.8495	0.0	0.1	1.8461	1.8496	1.8460	1.8492	0.0001	0.0003	0.5	1.8
2(1)	1.8495	1.8496	1.8493	1.8491	-0.1	0.2	1.8496	1.8492	1.8490	1.8491	0.0005	0.0001	2.9	0.5
3(1)	1.8512	1.8512	1.8479	1.8479	0.0	0.0	1.8512	1.8479	1.8509	1.8480	0.0003	-0.0001	1.6	-0.5
4	1.8533	1.8534	1.8487	1.8488	-0.1	-0.1	1.8534	1.8488	1.8529	1.8489	0.0004	-0.0002	2.4	-0.8
5	1.8467	1.8468	1.8441	1.8441	-0.1	0.0	1.8468	1.8441	1.8463	1.8439	0.0005	0.0002	2.4	1.1
6	1.8505	1.8506	1.8507	1.8505	-0.1	0.2	1.8506	1.8506	1.8500	1.8500	0.0006	0.0006	2.9	3.2
7	1.8515	1.8515	1.8535	1.8534	0.0	0.1	1.8515	1.8535	1.8511	1.8527	0.0004	0.0008	2.1	3.9
Top 8	1.8485	1.8485	1.8515	1.8513	0.0	0.2	1.8485	1.8514	1.8485	1.8512	0.0000	0.0002	0.0	1.1
			Measurement Pooled SDEV			0.08						AVG	1.8	1.3
			95 % Confidence			0.16						SDEV	1.1	1.7

Probe	3	
Material	2205 SS Operated At 172 F	
Location	Unit 2 Air Htr Outlet Duct	
Date	07/29/93 (Installed)	09/02/93 (removed)
Operating Hours	0	832
Meas Temp, F	70	70

	Initial Diameter, Inches				Measured Difference mils		Avg Initial Diameter inches		Final Diameter inches		Diameter Change inches		Corrosion Rate mils/yr	
Axial Score Line>	A	A(2)	B	B(2)	A	B	A	B	A	B	A	B	A	B
Ring Score #														
Bottom 1	1.8970	1.8970	1.8969	1.8970	0.0	-0.1	1.8970	1.8970	1.8969	1.8967	0.0001	0.0002	0.5	1.3
2(1)	1.8972	1.8972	1.8969	1.8969	0.0	0.0	1.8972	1.8969	1.8966	1.8967	0.0006	0.0002	3.2	1.1
3(1)	1.8969	1.8969	1.8971	1.8971	0.0	0.0	1.8969	1.8971	1.8965	1.8970	0.0004	0.0001	2.1	0.5
4	1.8968	1.8968	1.8971	1.8970	0.0	0.1	1.8968	1.8971	NA	1.8969	NA	0.0002	NA	0.8
5	1.8971	1.8972	1.8972	1.8971	-0.1	0.1	1.8972	1.8972	NA	1.8969	NA	0.0002	NA	1.3
6	1.8975	1.8976	1.8975	1.8975	-0.1	0.0	1.8976	1.8975	1.8967	1.8973	0.0008	0.0002	4.5	1.1
7	1.8974	1.8974	1.8973	1.8973	0.0	0.0	1.8974	1.8973	1.8967	1.8972	0.0007	0.0001	3.7	0.5
Top 8	1.8976	1.8974	1.8974	1.8974	0.2	0.0	1.8975	1.8974	1.8973	1.8973	0.0002	0.0001	1.1	0.5
			Measurement Pooled SDEV			0.05						AVG	2.5	0.9
			95 % Confidence			0.11						SDEV	1.5	0.3

(1) Controlled Temperature Located Midway Between These Two Scribe Marks.
(2) Duplicate Measurements
NA -- Not Applicable Because Wall Scraping Taken From Area For Metal Analysis

Table 2A
Air-Cooled Probe Measurements And Corrosion Rates
Milliken Station -- 7/15/93 to 1/14/94

Probe	1		
Material	Cor-Ten A Operated at 172 F		
Location	Unit 2 ESP Outlet Duct		
Date	07/15/93 (Installed)	01/14/94	(Removed)
Operating Hours	0	3832	
Meas Temp, F	70	73	

	Initial Diameter inches		Final Diameter inches		Diameter Change inches		Corrosion Rate mils/yr	
Axial Score Line>	A	B	A	B	A	B	A	B
Ring Score #								
Bottom 1	1.8595	1.8501	1.8589	1.8499	0.0006	0.0002	0.7	0.2
2(1)	1.8574	1.8530	1.8568	1.8531	0.0006	-0.0001	0.7	-0.1
3(1)	1.8552	1.8561	1.8546	1.8559	0.0006	0.0002	0.7	0.2
4	1.8539	1.8559	1.8536	1.8558	0.0003	0.0001	0.3	0.1
5	1.8554	1.8522	1.8550	1.8522	0.0004	0.0000	0.5	0.0
6	1.8568	1.8509	1.8564	1.8510	0.0004	-0.0001	0.5	-0.1
7	1.8530	1.8494	1.8527	1.8493	0.0003	0.0001	0.3	0.1
Top 8	1.8479	1.8483	1.8471	1.8483	0.0008	0.0000	0.9	0.0
						AVG	0.6	0.1
						SDEV	0.2	0.1

Probe	2		
Material	Cor-Ten A Operated At 202 F		
Location	Unit 2 ESP Outlet Duct		
Date	07/29/93 (Installed)	01/14/94	(Removed)
Operating Hours	0	3496	
Meas Temp, F	70	73	

	Avg Initial Diameter inches		Final Diameter inches		Diameter Change inches		Corrosion Rate mils/yr	
Axial Score Line>	A(2)	B(2)	A	B	A	B	A	B
Ring Score #								
Bottom 1	1.8461	1.8496	1.8455	1.8492	0.0006	0.0003	0.8	0.4
2(1)	1.8496	1.8492	1.8483	1.8490	0.0012	0.0002	1.6	0.3
3(1)	1.8512	1.8479	1.8502	1.8477	0.0010	0.0002	1.3	0.3
4	1.8534	1.8488	1.8523	1.8485	0.0010	0.0002	1.3	0.3
5	1.8468	1.8441	1.8458	1.8435	0.0010	0.0006	1.2	0.8
6	1.8506	1.8506	1.8495	1.8490	0.0011	0.0016	1.3	2.0
7	1.8515	1.8535	1.8502	1.8513	0.0013	0.0022	1.6	2.7
Top 8	1.8485	1.8514	1.8475	1.8511	0.0010	0.0003	1.3	0.4
						AVG	1.3	0.9
						SDEV	0.3	0.9

(1) Controlled Temperature Located Midway Between These Two Scribe Marks.

(2) Average of Two Measurements

Table 3A
Air-Cooled Probe Measurements And Corrosion Rates
Milliken Station -- 2/05/93 to 5/22/94

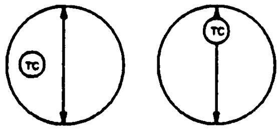
Probe	1			
Material	Cor-Ten A Operated at 192 F			
Location	Unit 2A Air Htr Outlet Duct			
Date	02/05/94	(Installed)	05/22/94	(Removed)
Operating Hours	0		2474	
Meas Temp, F	70		73	

	Initial Diameter inches		Final Diameter inches		Diameter Change inches		Corrosion Rate mils/yr	
Axial Score Line>	A	B	A	B	A	B	A	B
Ring Score #								
Bottom 1	1.8589	1.8499	1.8590	1.8495	-0.0001	0.0004	-0.2	0.7
2(1)	1.8568	1.8531	1.8569	1.8526	-0.0001	0.0005	-0.2	0.9
3(1)	1.8546	1.8559	1.8546	1.8555	0.0000	0.0004	0.0	0.7
4	1.8536	1.8558	1.8530	1.8554	0.0006	0.0004	1.1	0.7
5	1.8550	1.8522	1.8545	1.8519	0.0005	0.0003	0.9	0.5
6	1.8564	1.8510	1.8555	1.8504	0.0009	0.0006	1.6	1.1
7	1.8527	1.8493	1.8524	1.8490	0.0003	0.0003	0.5	0.5
Top 8	1.8471	1.8483	1.8468	1.8479	0.0003	0.0004	0.5	0.7
						AVG	0.5	0.7
						SDEV	0.6	0.2

Probe	2			
Material	Cor-Ten A Operated At 172 F			
Location	Unit 2B Air Htr Outlet Duct			
Date	02/05/94	(Installed)	05/22/94	(Removed)
Operating Hours	0		2378	
Meas Temp, F	70		73	

	Initial Diameter inches		Final Diameter inches		Diameter Change inches		Corrosion Rate mils/yr	
Axial Score Line>	A	B	A	B	A	B	A	B
Ring Score #								
Bottom 1	1.8455	1.8492	1.8442	1.8480	0.0013	0.0012	2.4	2.2
2(1)	1.8483	1.8490	1.8476	1.8482	0.0007	0.0008	1.3	1.5
3(1)	1.8502	1.8477	1.8497	1.8469	0.0005	0.0008	0.9	1.5
4	1.8523	1.8485	1.8523	1.8479	0.0000	0.0006	0.0	1.1
5	1.8458	1.8435	1.8457	1.8433	0.0001	0.0002	0.2	0.4
6	1.8495	1.8490	1.8494	1.8488	0.0001	0.0002	0.2	0.4
7	1.8502	1.8513	1.8499	1.8513	0.0003	0.0000	0.6	0.0
Top 8	1.8475	1.8511	1.8472	1.8510	0.0003	0.0001	0.6	0.2
						AVG	0.8	0.9
						SDEV	0.8	0.8

(1) Controlled Temperature Located Midway Between These Two Scribe Marks.



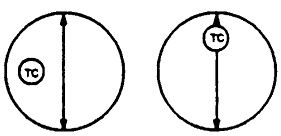
A B
Orientation

Table 4A
CAPCIS Probe Measurements And Corrosion Rates
Milliken Station -- 8/23/93 to 10/27/93

Probe	1		
Material	SA-178A CS Operated At 230 F		
Location	Unit 2A ESP Outlet Duct		
Date	08/25/93 (Installed)	10/27/93	(removed)
Operating Hours	0	1501	
Meas Temp, F	70	70	

Orientation	Initial Diameter inches		Final Diameter, inches				Measured Difference mils		Avg Final Diameter inches		Diameter Change inches		Corrosion Rate mils/yr	
Ring Number	A	B	A	A(1)	B	B(1)	A	B	A	B	A	B	A	B
Bottom 1	2.4825	2.4855	2.4845	2.4845	2.4830	2.4835	0.0	-0.5	2.4845	2.4833	-0.0020	0.0023	-5.8	6.6
2	2.4845	2.4850	2.4855	2.4850	2.4835	2.4835	0.5	0.0	2.4853	2.4835	-0.0007	0.0015	-2.2	4.4
3	2.4850	2.4850	2.4845	2.4850	2.4850	2.4850	-0.5	0.0	2.4848	2.4850	0.0002	0.0000	0.7	0.0
4	2.4835	2.4845	2.4845	2.4835	2.4840	2.4840	1.0	0.0	2.4840	2.4840	-0.0005	0.0005	-1.5	1.5
5	2.4875	2.4805	2.4860	2.4870	2.4805	2.4805	-1.0	0.0	2.4865	2.4805	0.0010	0.0000	2.9	0.0
6	2.4830	2.4830	2.4830	2.4825	2.4820	2.4825	0.5	-0.5	2.4828	2.4823	0.0002	0.0008	0.7	2.2
7	2.4825	2.4840	2.4825	2.4820	2.4835	2.4835	0.5	0.0	2.4823	2.4835	0.0002	0.0005	0.7	1.5
8	2.4805	2.4860	2.4805	2.4805	2.4855	2.4855	0.0	0.0	2.4805	2.4855	0.0000	0.0005	0.0	1.5
9	2.4830	2.4835	2.4830	2.4825	2.4825	2.4825	0.5	0.0	2.4828	2.4825	0.0002	0.0010	0.7	2.9
10	2.4815	2.4865	2.4810	2.4810	2.4860	2.4855	0.0	0.5	2.4810	2.4858	0.0005	0.0007	1.5	2.2
11	2.4830	2.4850	2.4825	2.4825	2.4845	2.4845	0.0	0.0	2.4825	2.4845	0.0005	0.0005	1.5	1.5
12	2.4820	2.4850	2.4815	2.4810	2.4845	2.4845	0.5	0.0	2.4813	2.4845	0.0008	0.0005	2.2	1.5
Top 13	2.4875	2.4820	2.4870	2.4870	2.4820	2.4825	0.0	-0.5	2.4870	2.4823	0.0005	-0.0002	1.5	-0.7
					Pooled Difference SDEV			0.29				AVG	0.2	1.9
					95 % Confidence			0.59				SDEV	2.3	1.9

(1) Duplicate Measurements



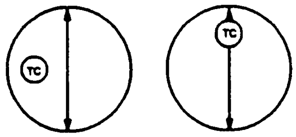
A B
Orientation

Table 5A
CAPCIS Probe Measurements And Corrosion Rates
Milliken Station -- 11/08/93 to 1/14/94

Probe	1		
Material	SA-178A CS Operated At 168 F		
Location	Unit 2A ESP Outlet Duct		
Date	11/08/93 (Installed)	01/14/94	(removed)
Operating Hours	0	1609	
Meas Temp, F	70	73	

Orientation	Avg Initial Diameter inches		Final Diameter inches		Diameter Change inches		Corrosion Rate mils/yr	
Ring Number	A(1)	B(1)	A	B	A	B	A	B
Bottom 1	2.4845	2.4833	2.4845	2.4855	0.0000	-0.0023	0.0	-6.1
2	2.4853	2.4835	2.4850	2.4845	0.0002	-0.0010	0.7	-2.7
3	2.4848	2.4850	2.4850	2.4845	-0.0002	0.0005	-0.7	1.4
4	2.4840	2.4840	2.4835	2.4845	0.0005	-0.0005	1.4	-1.4
5	2.4865	2.4805	2.4870	2.4795	-0.0005	0.0010	-1.4	2.7
6	2.4828	2.4823	2.4825	2.4830	0.0003	-0.0008	0.7	-2.0
7	2.4823	2.4835	2.4825	2.4840	-0.0002	-0.0005	-0.7	-1.4
8	2.4805	2.4855	2.4805	2.4855	0.0000	0.0000	0.0	0.0
9	2.4828	2.4825	2.4825	2.4830	0.0003	-0.0005	0.7	-1.4
10	2.4810	2.4858	2.4810	2.4865	0.0000	-0.0007	0.0	-2.0
11	2.4825	2.4845	2.4825	2.4845	0.0000	0.0000	0.0	0.0
12	2.4813	2.4845	2.4815	2.4850	-0.0002	-0.0005	-0.7	-1.4
Top 13	2.4870	2.4823	2.4865	2.4800	0.0005	0.0023	1.4	6.1
						AVG	0.1	-0.6
						SDEV	0.8	2.9

(1) Average of two Measurements

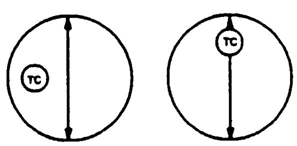


A B
Orientation

Table 6A
CAPCIS Probe Measurements And Corrosion Rates
Milliken Station -- 2/07/94 to 5/22/94

Probe	1		
Material	SA-178A CS Operated At 172 F		
Location	Unit 2A ESP Outlet Duct		
Date	02/07/94 (Installed)	05/22/94 (removed)	
Operating Hours	0	2487	
Meas Temp, F	70	79	

Orientation / Ring Number	Initial Diameter inches A	Initial Diameter inches B	Final Diameter inches A	Final Diameter inches B	Diameter Change inches A	Diameter Change inches B	Corrosion Rate mils/yr A	Corrosion Rate mils/yr B
Bottom 1	2.4845	2.4855	2.4825	2.4830	0.0020	0.0025	3.5	4.4
2	2.4850	2.4845	2.4825	2.4825	0.0025	0.0020	4.4	3.5
3	2.4850	2.4845	2.4825	2.4835	0.0025	0.0010	4.4	1.8
4	2.4835	2.4845	2.4820	2.4830	0.0015	0.0015	2.6	2.6
5	2.4870	2.4795	2.4845	2.4785	0.0025	0.0010	4.4	1.8
6	2.4825	2.4830	2.4810	2.4805	0.0015	0.0025	2.6	4.4
7	2.4825	2.4840	2.4805	2.4820	0.0020	0.0020	3.5	3.5
8	2.4805	2.4855	2.4785	2.4840	0.0020	0.0015	3.5	2.6
9	2.4825	2.4830	2.4805	2.4810	0.0020	0.0020	3.5	3.5
10	2.4810	2.4865	2.4790	2.4850	0.0020	0.0015	3.5	2.6
11	2.4825	2.4845	2.4810	2.4830	0.0015	0.0015	2.6	2.6
12	2.4815	2.4850	2.4800	2.4830	0.0015	0.0020	2.6	3.5
Top 13	2.4865	2.4800	2.4845	2.4795	0.0020	0.0005	3.5	0.9
						AVG	3.5	2.9
						SDEV	0.7	1.0



A B
Orientation

Table 7A
CAPCIS Probe Measurements And Corrosion Rates
Milliken Station -- 2/07/94 to 5/22/94

Probe	2		
Material	Cor-Ten A Operated At 172 F		
Location	Slipstream Heat Pipe Outlet		
Date	02/07/94 (Installed)	05/22/94 (removed)	
Operating Hours	0	2487	
Meas Temp, F	70	79	

Orientation / Ring Number	Initial Diameter inches A	A(1)	B	B(1)	Measured Difference mils A	B	Avg Initial Diameter inches A avg	B avg	Final Diameter inches A	B	Diameter Change Inches A	B	Corrosion Rate mils/yr A	B
Bottom 1	2.4970	2.4975	2.4975	2.4975	-0.5	0.0	2.4973	2.4975	2.4965	2.4965	0.0008	0.0010	1.3	1.8
2	2.4970	2.4970	2.4970	2.4970	0.0	0.0	2.4970	2.4970	2.4965	2.4960	0.0005	0.0010	0.9	1.8
3	2.4970	2.4975	2.4975	2.4975	-0.5	0.0	2.4973	2.4975	2.4965	2.4960	0.0008	0.0015	1.3	2.6
4	2.4975	2.4975	2.4975	2.4970	0.0	0.5	2.4975	2.4973	2.4965	2.4960	0.0010	0.0013	1.8	2.2
5	2.4970	2.4970	2.4975	2.4975	0.0	0.0	2.4970	2.4975	2.4960	2.4960	0.0010	0.0015	1.8	2.6
6	2.4965	2.4965	2.4965	2.4965	0.0	0.0	2.4965	2.4965	2.4950	2.4955	0.0015	0.0010	2.6	1.8
7	2.4965	2.4970	2.4970	2.4970	-0.5	0.0	2.4968	2.4970	2.4955	2.4960	0.0013	0.0010	2.2	1.8
8	2.4965	2.4965	2.4975	2.4975	0.0	0.0	2.4965	2.4975	2.4955	2.4965	0.0010	0.0010	1.8	1.8
9	2.4965	2.4970	2.4975	2.4975	-0.5	0.0	2.4968	2.4975	2.4955	2.4965	0.0013	0.0010	2.2	1.8
10	2.4970	2.4975	2.4975	2.4970	-0.5	0.5	2.4973	2.4973	2.4965	2.4960	0.0008	0.0013	1.3	2.2
11	2.4970	2.4975	2.4975	2.4970	-0.5	0.5	2.4973	2.4973	2.4965	2.4960	0.0008	0.0013	1.3	2.2
12	2.4975	2.4975	2.4975	2.4980	0.0	-0.5	2.4975	2.4978	2.4965	2.4970	0.0010	0.0008	1.8	1.3
Top 13	2.4975	2.4975	2.4975	2.4975	0.0	0.0	2.4975	2.4975	2.4965	2.4970	0.0010	0.0005	1.8	0.9
			Pooled Difference SDE			0.22						AVG	1.7	1.9
			95 % Confidence			0.44						SDEV	0.5	0.5

(1) Duplicate Measurements

Table 8A
CAPCIS Daily Average Corrosion Rates -- SA-178A
Milliken Station Unit 2 ESP Outlet

Date	ECN	mils/yr	Probe Temp, F	Gas Temp, F	Date	ECN	mils/yr	Probe Temp, F	Gas Temp, F
08/26/93	4.13E-09	1.81	237	239	10/01/93	5.03E-09	2.21	227	228
08/27/93	3.94E-09	1.73	237	245	10/02/93	4.43E-09	1.95	235	238
08/28/93	9.08E-09	3.99	238	248	10/03/93	5.06E-09	2.22	231	232
08/29/93	1.08E-08	4.73	237	237	10/04/93	5.04E-09	2.21	232	233
08/29/93	3.47E-09	1.52	235	243	10/05/93	5.52E-09	2.42	228	229
08/30/93	4.42E-09	1.94	235	240	10/06/93	4.96E-09	2.18	231	232
08/31/93	2.73E-09	1.20	235	246	10/07/93	3.86E-09	1.69	234	242
09/01/93	DATA LOSS				10/08/93	3.19E-09	1.40	234	242
09/02/93	DATA LOSS				10/09/93	5.07E-09	2.23	232	233
09/03/93	DATA LOSS				10/10/93	5.73E-09	2.51	225	226
09/04/93	DATA LOSS				10/11/93	4.82E-09	2.12	224	225
09/05/93	DATA LOSS				10/12/93	5.29E-09	2.32	230	230
09/06/93	4.82E-09	2.12	235	235	10/13/93	5.89E-09	2.59	226	226
09/07/93	5.30E-09	2.33	235	238	10/14/93	4.41E-09	1.93	228	228
09/08/93	4.78E-09	2.10	234	239	10/15/93	4.91E-09	2.16	231	233
09/09/93	4.10E-09	1.80	235	241	10/16/93	4.16E-09	1.83	234	238
09/10/93	4.02E-09	1.77	232	234	10/17/93	3.81E-09	1.67	235	236
09/11/93	5.53E-09	2.43	232	233	10/18/93	4.99E-09	2.19	231	231
09/12/93	5.23E-09	2.30	230	232	10/19/93	5.35E-09	2.35	225	225
09/13/93	5.38E-09	2.36	234	246	10/20/93	6.28E-09	2.76	229	229
09/14/93	6.08E-09	2.67	233	237	10/21/93	5.72E-09	2.51	231	232
09/15/93	1.12E-08	4.93	233	253	10/22/93	6.00E-09	2.63	232	232
09/16/93	7.52E-09	3.30	232	237	10/23/93	5.58E-09	2.45	231	232
09/17/93	5.60E-09	2.46	234	239	10/24/93	4.56E-09	2.00	234	235
09/18/93	5.54E-09	2.43	234	239	10/25/93	5.56E-09	2.44	233	233
09/19/93	5.12E-09	2.25	233	236	10/26/93	5.37E-09	2.36	223	235
09/20/93	3.76E-09	1.65	226	227	10/27/93	5.31E-09	2.33	198	235
09/21/93	5.44E-09	2.39	228	229	10/28/93	INSPECTION -- PROBE REMOVED			
09/22/93	5.13E-09	2.25	230	232	10/29/93	INSPECTION -- PROBE REMOVED			
09/23/93	5.47E-09	2.40	233	238	10/30/93	INSPECTION -- PROBE REMOVED			
09/24/93	5.57E-09	2.44	233	238	10/31/93	INSPECTION -- PROBE REMOVED			
09/25/93	4.59E-09	2.02	233	235					
09/26/93	4.44E-09	1.95	234	236					
09/27/93	5.27E-09	2.31	232	232					
09/28/93	5.75E-09	2.52	229	229					
09/29/93	4.80E-09	2.11	226	227					
09/30/93	4.58E-09	2.01	225	225					

Table 8A (Continued)
CAPCIS Daily Average Corrosion Rates -- SA-178A
Milliken Station Unit 2 ESP Outlet

Date	ECN	mils/yr	Probe Temp, F	Gas Temp, F
11/01/93	INSPECTION -- PROBE REMOVED			
11/02/93	INSPECTION -- PROBE REMOVED			
11/03/93	INSPECTION -- PROBE REMOVED			
11/04/93	INSPECTION -- PROBE REMOVED			
11/05/93	INSPECTION -- PROBE REMOVED			
11/06/93	INSPECTION -- PROBE REMOVED			
11/07/93	INSPECTION -- PROBE REMOVED			
11/08/93	5.85E-09	2.57	172	228
11/09/93	4.42E-09	1.94	171	226
11/10/93	4.49E-09	1.97	171	226
11/11/93	5.45E-09	2.39	172	227
11/12/93	4.99E-09	2.19	172	226
11/13/93	4.01E-09	1.76	171	223
11/14/93	4.74E-09	2.08	174	232
11/15/93	5.35E-09	2.35	174	232
11/16/93	4.99E-09	2.19	172	226
11/17/93	4.19E-09	1.84	171	224
11/18/93	4.93E-09	2.16	172	225
11/19/93	3.69E-09	1.62	171	226
11/20/93	3.67E-09	1.61	171	219
11/21/93	4.04E-09	1.77	170	217
11/22/93	5.22E-09	2.29	168	230
11/23/93	5.12E-09	2.25	166	227
11/24/93	3.05E-09	1.34	168	227
11/25/93	4.12E-09	1.81	167	222
11/26/93	3.51E-09	1.54	168	226
11/27/93	5.21E-09	2.29	170	228
11/28/93	4.88E-09	2.14	170	229
11/29/93	2.94E-09	1.29	169	222
11/30/93	3.05E-09	1.34	169	221
12/01/93	3.42E-09	1.50	168	222
12/02/93	4.14E-09	1.82	169	225
12/03/93	5.36E-09	2.35	170	225
12/04/93	4.85E-09	2.13	170	224
12/05/93	4.33E-09	1.90	170	222
12/06/93	4.05E-09	1.78	169	222
12/07/93	4.25E-09	1.87	169	223
12/08/93	3.15E-09	1.38	169	222
12/09/93	3.89E-09	1.71	168	188
12/10/93	3.34E-09	1.46	169	219
12/11/93	3.35E-09	1.47	168	216
12/12/93	3.31E-09	1.45	167	210
12/13/93	2.91E-09	1.28	167	218
12/14/93	2.26E-09	0.99	168	226
12/15/93	3.08E-09	1.35	168	224

Date	ECN	mils/yr	Probe Temp, F	Gas Temp, F
12/16/93	2.75E-09	1.21	168	222
12/17/93	2.69E-09	1.18	167	230
12/18/93	2.65E-09	1.16	168	229
12/19/93	3.05E-09	1.34	169	229
12/20/93	3.19E-09	1.40	169	224
12/21/93	3.79E-09	1.66	169	223
12/22/93	3.14E-09	1.38	169	222
12/23/93	4.31E-09	1.89	166	217
12/24/93	5.97E-09	2.62	164	211
12/25/93	3.17E-09	1.39	165	215
12/26/93	6.11E-09	2.68	165	208
12/27/93	8.78E-09	3.86	164	207
12/28/93	5.83E-09	2.56	165	212
12/29/93	8.20E-09	3.60	164	211
12/30/93	2.84E-09	1.25	166	214
12/31/93	3.85E-09	1.69	166	220
01/01/94	2.83E-09	1.24	167	224
01/02/94	2.96E-09	1.30	167	224
01/03/94	5.78E-09	2.54	165	217
01/04/94	5.21E-09	2.29	165	217
01/05/94	4.08E-09	1.79	166	214
01/06/94	8.50E-09	3.73	164	209
01/07/94	7.67E-09	3.37	164	210
01/08/94	5.55E-09	2.44	165	210
01/09/94	5.99E-09	2.63	165	211
01/10/94	7.40E-09	3.25	165	209
01/11/94	3.03E-09	1.33	165	218
01/12/94	2.29E-09	1.01	166	224
01/13/94	1.86E-09	0.82	166	224
01/14/94	2.82E-09	1.24	166	219

Table 9A
CAPCIS Daily Average Corrosion Rates -- SA-178A
Milliken Station -- Slipstream Heat Pipe Outlet

Date	ECN	mils/yr	Probe Temp, F	Gas Temp, F	Date	ECN	mils/yr	Probe Temp, F	Gas Temp, F
02/07/94	7.17E-09	3.15	154	313	04/01/94	5.74E-09	2.52	180	257
02/08/94	4.51E-09	1.98	158	308	04/02/94	6.42E-09	2.82	181	253
02/09/94	5.86E-09	2.57	166	314	04/03/94	5.56E-09	2.44	179	260
02/10/94	1.01E-08	4.45	172	321	04/04/94	3.99E-09	1.75	177	263
02/11/94	1.19E-08	5.23	175	300	04/05/94	5.53E-09	2.43	181	261
02/12/94	1.32E-08	5.81	180	295	04/06/94	5.57E-09	2.45	179	270
02/13/94	1.41E-08	6.20	181	296	04/07/94	5.67E-09	2.49	176	274
02/14/94	1.51E-08	6.61	178	294	04/08/94	3.71E-09	1.63	176	279
02/15/94	1.40E-08	6.14	181	294	04/09/94	6.74E-09	2.96	179	276
02/16/94	1.35E-08	5.94	181	294	04/10/94	3.13E-09	1.37	180	282
02/17/94	1.05E-08	4.60	184	291	04/11/94	3.35E-09	1.47	177	285
02/18/94	8.39E-09	3.68	186	291	04/12/94	SYSTEM SHUTDOWN FOR WASH OUT			
02/19/94	6.95E-09	3.05	189	279	04/13/94	2.41E-09	1.06	184	260
02/20/94	6.42E-09	2.82	187	293	04/14/94	2.87E-09	1.26	172	268
02/21/94	7.20E-09	3.16	182	293	04/15/94	3.04E-09	1.33	174	272
02/22/94	8.25E-09	3.62	177	296	04/15/94	3.04E-09	1.33	174	272
02/23/94	8.51E-09	3.74	174	304	04/16/94	2.44E-09	1.07	172	271
02/24/94	9.78E-09	4.29	174	308	04/17/94	2.97E-09	1.30	170	266
02/25/94	8.42E-09	3.70	172	314	04/18/94	2.28E-09	1.00	172	261
02/26/94	8.60E-09	3.78	171	315	04/19/94	1.92E-09	0.84	174	259
02/27/94	8.78E-09	3.85	171	321	04/20/94	3.20E-09	1.41	170	267
02/28/94	8.78E-09	3.86	176	308	04/21/94	3.80E-09	1.67	168	263
					04/22/94	DATA LOSS			
03/01/94	1.04E-08	4.57	179	303	04/23/94	DATA LOSS			
03/02/94	1.15E-08	5.06	181	291	04/24/94	DATA LOSS			
03/03/94	1.24E-08	5.44	182	296	04/25/94	DATA LOSS			
03/04/94	1.08E-08	4.75	182	292	04/26/94	1.48E-09	0.65	175	266
03/05/94	8.39E-09	3.68	178	291	04/27/94	1.24E-09	0.55	176	265
03/06/94	8.30E-09	3.64	176	299	04/28/94	3.81E-09	1.67	170	264
03/07/94	6.74E-09	2.96	178	298	04/29/94	7.73E-09	3.40	70	65
03/08/94	7.61E-09	3.34	178	305	04/30/94	9.63E-09	4.23	59	54
03/09/94	5.96E-09	2.62	177	307					
03/10/94	6.95E-09	3.05	177	307	05/01/94	1.82E-08	7.99	62	58
03/11/94	4.94E-09	2.17	175	316	05/02/94	3.48E-09	1.53	66	61
03/12/94	5.14E-09	2.26	171	330	05/03/94	2.39E-09	1.05	59	54
03/13/94	4.94E-09	2.17	176	318	05/04/94	2.39E-09	1.05	67	62
03/14/94	5.50E-09	2.41	179	308	05/05/94	1.37E-08	6.01	73	69
03/15/94	4.41E-09	1.94	183	291	05/06/94	3.89E-08	17.08	56	51
03/16/94	3.17E-09	1.39	179	297	05/07/94	3.80E-08	16.68	57	53
03/17/94	3.01E-09	1.32	177	307	05/08/94	9.58E-09	4.21	57	53
03/18/94	3.27E-09	1.44	178	303	05/09/94	4.36E-08	19.14	61	57
03/19/94	3.22E-09	1.41	181	298	05/10/94	6.08E-08	26.68	57	52
03/20/94	3.17E-09	1.39	182	292	05/11/94	DATA LOSS AND SHUTDOWN			
03/21/94	4.57E-09	2.01	165	287	05/12/94	DATA LOSS AND SHUTDOWN			
03/22/94	3.21E-09	1.41	167	282	05/13/94	DATA LOSS AND SHUTDOWN			
03/23/94	2.67E-09	1.17	168	262	05/14/94	2.26E-08	9.93	173	250
03/24/94	3.16E-09	1.39	160	284	05/15/94	1.93E-08	8.47	173	241
03/25/94	3.37E-09	1.48	173	288	05/16/94	1.71E-08	7.51	174	239
03/26/94	5.48E-09	2.41	172	280	05/17/94	2.09E-08	9.18	171	241
03/27/94	8.47E-09	3.72	174	277	05/18/94	1.76E-08	7.73	171	241
03/28/94	7.15E-09	3.14	174	273	05/19/94	DATA LOSS			
03/29/94	7.00E-09	3.07	176	260	05/20/94	3.39E-08	14.88	175	250
03/30/94	5.19E-09	2.28	174	280	05/21/94	2.65E-08	11.63	175	244
03/31/94	3.57E-09	1.57	175	272	05/22/94	1.84E-08	8.08	175	244
						SHUTDOWN			

Table 10A
CAPCIS Daily Average Corrosion Rates -- Cor-Ten A
Milliken Station -- Slipstream Heat Pipe Outlet

Date	ECN	mils/yr	Probe Temp, F	Gas Temp, F
02/07/94	2.17E-09	0.14	186	320
02/08/94	2.27E-08	1.46	182	314
02/09/94	2.12E-08	1.36	174	323
02/10/94	1.76E-08	1.14	175	333
02/11/94	2.54E-08	1.64	175	311
02/12/94	2.21E-08	1.42	173	302
02/13/94	2.48E-08	1.60	175	303
02/14/94	2.40E-08	1.55	176	301
02/15/94	3.65E-08	2.35	174	302
02/16/94	2.54E-08	1.64	174	302
02/17/94	2.18E-08	1.41	174	299
02/18/94	2.51E-08	1.61	174	299
02/19/94	4.49E-08	2.89	173	287
02/20/94	5.94E-08	3.82	173	298
02/21/94	3.14E-08	2.02	173	297
02/22/94	2.60E-08	1.67	175	303
02/23/94	2.73E-08	1.76	174	311
02/24/94	2.34E-08	1.51	174	316
02/25/94	2.08E-08	1.34	174	321
02/26/94	2.65E-08	1.71	175	318
02/27/94	2.48E-08	1.60	176	324
02/28/94	2.35E-08	1.52	175	310
03/01/94	3.07E-08	1.98	174	307
03/02/94	2.97E-08	1.92	173	295
03/03/94	2.42E-08	1.56	173	301
03/04/94	2.55E-08	1.64	173	296
03/05/94	3.01E-08	1.94	173	297
03/06/94	3.04E-08	1.96	173	303
03/07/94	3.29E-08	2.12	173	302
03/08/94	2.87E-08	1.85	173	307
03/09/94	2.05E-08	1.32	174	315
03/10/94	3.48E-09	0.22	173	314
03/11/94	4.20E-09	0.27	172	321
03/12/94	3.48E-09	0.22	173	325
03/13/94	1.40E-09	0.09	172	297
03/14/94	1.63E-08	1.05	172	290
03/15/94	1.95E-08	1.26	172	287
03/16/94	1.24E-08	0.80	173	296
03/17/94	2.08E-08	1.34	173	301
03/18/94	1.60E-08	1.03	174	301
03/19/94	2.32E-08	1.49	172	293
03/20/94	2.85E-08	1.83	172	286
03/21/94	3.09E-08	1.99	182	284
03/22/94	3.44E-08	2.22	173	276
03/23/94	4.42E-08	2.85	172	261
03/24/94	2.96E-08	1.91	173	283
03/25/94	2.85E-08	1.83	173	288
03/26/94	3.04E-08	1.96	173	279
03/27/94	3.19E-08	2.05	172	274
03/28/94	3.08E-08	1.98	173	272
03/29/94	3.16E-08	2.03	172	259
03/30/94	3.32E-08	2.14	173	276
03/31/94	3.92E-08	2.52	173	268

Date	ECN	mils/yr	Probe Temp, F	Gas Temp, F
04/01/94	4.17E-08	2.68	173	253
04/02/94	4.58E-08	2.95	173	249
04/03/94	4.48E-08	2.88	173	256
04/04/94	3.48E-08	2.24	173	257
04/05/94	4.84E-08	3.12	173	253
04/06/94	3.36E-08	2.16	174	260
04/07/94	2.95E-08	1.90	174	264
04/08/94	3.32E-08	2.14	174	270
04/09/94	4.85E-08	3.13	174	272
04/10/94	5.10E-08	3.29	174	274
04/11/94	3.51E-08	2.26	175	274
04/12/94	SYSTEM SHUTDOWN FOR WASH OUT			
04/13/94	4.48E-08	2.88	173	245
04/14/94	5.04E-08	3.24	173	252
04/15/94	3.93E-08	2.53	173	256
04/15/94	2.77E-10	0.02	174	256
04/16/94	3.70E-08	2.38	175	258
04/17/94	4.27E-08	2.75	174	258
04/18/94	4.95E-08	3.19	173	258
04/19/94	4.21E-08	2.71	174	258
04/20/94	3.79E-08	2.44	174	258
04/21/94	2.94E-08	1.89	174	258
04/22/94		DATA LOSS		
04/23/94		DATA LOSS		
04/24/94		DATA LOSS		
04/25/94		DATA LOSS		
04/26/94	2.94E-08	1.89	174	253
04/27/94	3.37E-08	2.17	174	251
04/28/94	3.18E-08	2.05	174	250
04/29/94	7.15E-09	0.46	58	57
04/30/94	6.25E-09	0.40	49	47
05/01/94	5.04E-09	0.32	51	50
05/02/94	8.58E-09	0.55	58	56
05/03/94	1.03E-08	0.66	52	50
05/04/94	8.95E-09	0.58	59	57
05/05/94	2.72E-08	1.75	51	50
05/06/94	3.35E-09	0.22	46	45
05/07/94	2.98E-09	0.19	46	45
05/08/94	1.49E-08	0.96	47	46
05/09/94	1.54E-09	0.10	50	49
05/10/94	1.21E-09	0.08	47	45
05/11/94	DATA LOSS AND SHUTDOWN			
05/12/94	DATA LOSS AND SHUTDOWN			
05/13/94	DATA LOSS AND SHUTDOWN			
05/14/94	6.55E-08	4.22	174	246
05/15/94	5.10E-08	3.29	174	237
05/16/94	4.50E-08	2.90	172	237
05/17/94	3.47E-08	2.23	172	235
05/18/94	3.47E-08	2.23	172	239
05/19/94		DATA LOSS		
05/20/94	3.85E-08	2.48	172	244
05/21/94	3.70E-08	2.38	172	243
05/22/94	4.83E-08	3.11	172	243
		SHUTDOWN		