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May 15, 2009

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Project:. 0900235.00
Report: 0900235.402 R0

Subject: **Analysis of 8" Condensate Water Storage Tank Return Line CD-183**
Final report

Dear Robert:

The report of our failure analysis of the leaking condensate piping is attached for your review. This final version contains no changes to Draft B, (other than the date of distribution and an updated report number) which you have reviewed and approved. Please contact me if you have any technical questions about this report, or Ken Rach for questions regarding any administrative issues about this project.

Best Regards,

William E. Amend

Associate

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Project 0900235.00
Report No. 0900235.402
May 15, 2009

ANALYSIS OF 8" CONDENSATE RETURN LINE FAILURE

Prepared For:

Entergy, Indian Point Nuclear Station

Prepared By:

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Reviewed By: : George Licina, Chief Materials Consultant — Date: May 11, 2009

Approved By: Ken Rach, Associate — Date: May 15, 2009

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REVISION CONTROL SHEET

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Client:	Entergy– Indian Point Nuclear Station
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Section	Pages	Revision	Date	Comments
All	All	Draft A	4/9/09	Initial Draft for Review
All	All	Draft B	5/8/09	Second draft for Review
All	All	Final	5/15/09	No changes to draft B

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ANALYSIS OF 8" CONDENSATE RETURN LINE FAILURE

Executive Summary

The leak in the steel condensate piping was caused by external corrosion. Patterns of corrosion on the piping and observations of the backfill indicate that the corrosion on the pipe occurred at localized areas of coating damage that most likely occurred during installation of the pipe or during installation of the fill. The corrosion on the elbow is more widespread than on the straight section of pipe and is typical of corrosion related to difficulties in applying a good quality wrap coating on a more difficult or irregular shape. It is likely that similar corrosion exists on adjacent piping if exposed to comparable soil conditions. The piping was not cathodically protected.

Corrosion on the inside surfaces was superficial.

No evidence of cracking was observed.

The metallurgical characteristics of the pipe and elbow were normal and the workmanship of the girth weld was good. Where corrosion pitting was present on the weld, the weld metal appeared to be more resistant to corrosion than the adjacent heat affected zone or base metal.

The analysis results did not definitively determine the mechanism of the external corrosion. Features of the corrosion (morphology and corrosion products) support a determination that the corrosion is either the result of exposure to a specific range of ground water characteristics, and/or to microbiologically influenced corrosion (MIC). The corrosion was not consistent with the characteristics of stray current corrosion, even though stray current was previously identified on other buried pipe at the plant.

XRD (x-ray diffraction analysis) showed that the ID corrosion products were generally iron oxides and hydroxides. The OD corrosion product was primarily siderite, an iron carbonate. The difference in corrosion products on the ID and OD indicate that the corrosion on the two surfaces is unrelated.

Recommendations related to selection of locations for further inspection, corrosion monitoring, and soil sampling are included.

Introduction

Indian Point Generating Station Unit 2 (Indian Point) experienced a leak on 8 inch buried piping identified as Condensate Storage Tank Return Line CD-183. The circumstances regarding the discovery of the leak are described in the narrative by Engineering staff in Appendix A. SI performed a long range guided wave (G-Scan™) inspection on February 17th, 2009. to screen several pre-selected sections of pipe for wall loss[1]. The inspection was performed while the

[1]Bass, A., " G-Scan™ Assessment of 8" Condensate Water Storage Tank Return Line CD-183, Inspection Date: February 17th, 2009",SI report no. 0900235.401.R0, March 13, 2009.

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plant was in operation and water was flowing through the pipes. After identifying the leak location and adjacent areas of significant wall loss, Indian Point excavated the area and in accordance with their Technical Specifications replaced the leaking section of the piping..

As described in SI proposal 0900308.00 Rev. 1 of March 20, 2009, the objective of this analysis was to determine the probable failure mechanism and describe the overall condition of the pipe sample. Background information pertaining to the condensate piping is described in the next section. The piping sample was received by SI on March 23, 2009 after removal of the potentially hazardous external coating and related decontamination by Entergy.

Background Information

The following information was provided to SI by the staff of Entergy in response to our request for pertinent background information.

Table 1 –Background Information

Item	Inquiry	Response
1	Applicable design standard(s) for this piping (list applicable industry standard and company standards, particularly if company standards impose additional restrictions related to materials, construction, testing, or inspection) Copies of company or A-E specs	Construction code is B31.1 1955. Design piping specification- 9321-01-248-18 Class C-1. Lacquer coating by spool fabricator (dwg 17D523) All underground piping to be field coated and wrapped in accordance with AWWA spec C-203. Specification imposes no additional restrictions.
2	Installation year	Piping installed in late 1960's
3	Expected life or design life of this piping	Design life of pipe is not specified or known. Design life of plant is 40 years.
4	Expected life limited by what? (external corrosion following coating degradation, internal corrosion, fatigue, no longer needed, etc.)	Pipe life limitation appears to be based upon life of external coating. Based upon visual results, Entergy staff noted that the areas of pipe where coating was intact appears like new and has no external corrosion. Internal corrosion appears minor.
5	Specified wall thickness	Specified wall thickness- 0.322" (nominal wall thickness for 8"SCH40 pipe)
6	Minimum design thickness	Min design thickness- 0.064" per calculation IP-CALC-09-00035
7	Specified diameter	Pipe diameter-8"
8	Specified grade (pipe and elbow)	Pipe- A106 Gr B, Elbow- A234 WCB
9	Design pressure	665 PSIG
10	Normal operating pressure (including ranges)	Static head- approximately 45 PSIG at leak location

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11	Original test pressure	Original test pressure unknown. Spool fabrication drawing does not specify a test pressure. After installation, one end is open to atmospheric tank. Not known if B31.1 hydrostatic test was performed.
12	Periodic test pressure (if any) and date of last test	Static head- Last test date unknown- Pressure drop test once every 3 years. Ref 2PT-3Y7
13	Description of the fluid on ID	Clean condensate
14	Operating temperature	90 to 115°F
15	Operating conditions consistent?	Continuous flow
16	Original construction inspection (radiography?, visual? UT?, other?)	Visual inspection of welds
17	Any other periodic inspection, monitoring, or testing	Pressure drop test once every 3 years. Ref 2PT-3Y7
18	Approximate depth of burial	Seven feet at leak location from top of building concrete floor slab
19	Specified backfill (description of what the pipe was supposed to be buried in)	Per specification 9321-01-8-4. This specification does not describe requirements for backfill materials below two feet below grade
20	Observed condition of backfill (as expected per item #19, wet, dry, contaminated by construction debris, rocky, gravelly, sandy, clay, other?)	See interview reports in Appendix A.
21	Measured soil resistivity	No soil resistivity measurements available for the location of the leak. Soil resistivity measurements for soil around this pipe approximately 100 feet and 200 feet from the leak location are described in Background Reference #7 and range from 8000 ohm-cm to 63,000 ohm-cm depending upon location and depth.
22	Any other soil analysis results available?	See 21 above and Background References #8 and #9.
23	Specified external coating (thickness, type, manufacturer, inspection or QA methods used during construction and installation) (refer also to item #1)	External coatings per specification AWWA C-203 "Coal-Tar Protective Coatings And Linings For Steel Water Pipelines - Enamel And Tape - Hot Applied"
24	Coating on welds same as coating on pipe?	The same coating was used on pipe and on welds.
25	Observed condition of coating upon excavation (mechanically damaged, disbonded, water under coating, obvious degradation, etc.)	See interview reports in Appendix A

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26	Electrically continuous with different alloys? If so, what alloys and how far away.	No other buried alloys as part of this condensate piping. The copper grounding grid is believed to be electrically continuous with this piping
27	Cathodic protection installed? If so, describe system type (impressed current, galvanic) and history of potentials, CP maintenance, or operational history	No cathodic protection installed on this system. CP is installed on some other underground systems as described in Background Reference #7
30	Any potential source of electrical interference or history of lightning strikes or ground faults or source of electrical current pick-up and discharge from this pipe?	No known electrical interference, lightening strikes, etc. on this piping. Background Reference #7 does describe interference on another piping system related to a crossing foreign line that is cathodically protected
29	Free corrosion potential (potential of unprotected steel in the same backfill vs. Cu-CuSO4 reference electrode)	Potential measurements are listed in Background reference #7. The measurements range from -248 mV to -328 mV (some possible minor effects of active CP elsewhere in the plant, although this pipe was not cathodically protected)
31	History of significant external corrosion on adjacent piping, if so, describe pipe, service conditions, and approx. date of discovery	No corrosion history on adjacent 12" pipe (same fluid & design). The adjacent 12" line is coated the same as the failed pipe and carrying the same fluid. A 10" CMP drain line is approximately 12 feet from the failed piping at the leak location. The drain line is coated with the same coating as the failed pipe.
32	Any new pipe installations in this line or near by	No new pipe installations
33	Any photographic information from the leak location.	See Figures 1-3 of this report

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Table 2 - Other Background Reference Materials Provided by Entergy Staff for Review

1	UT survey results for the 8" CST pipe, "UT Erosion/Corrosion Examination" report IP2-UT-09-010
2	Relicensing Ground Water Samples. Xls
3	Relicensing Sample Locations.doc (Monitoring Well locations)
4	Attachment 1 IP2 FSAR CP Discussion: This documents the original plant design information concerning underground piping, cathodic protection and soil resistivity.
5	Attachment 2 CST Lines.pdf: This shows the locations of the excavations performed on this line in 2008. This is an elevation view. The leak was at the very bottom left and the 1st excavation is off the page at the top right.
6	Attachment 3 Condition Report : This is a report on the condition of the coating and pipe in the first excavation.
7	Attachment 4 "Corrosion/Cathodic Protection Field Survey and Assessment of Underground Structures at Indian Point Energy Center Unit Nos. 2 and 3 during October 2008" prepared by PCA Engineering, revised December 2 2008?.
8	Attachment 5 GEL Labs 11-07-08 Soil Sample Package for Engineerng.pdf: This is the report of the soil evaluation performed for the two 2008 excavations. They are labeled U2-CST-1 through 4.
9	Attachment 6 02-20-09 Soil Sample Results Package.pdf(2) : This is the soil analysis from the leak location taken 2-20-2009.
10	"Specification for Placing & Compaction of Backfill", Spec. No. 9321-01-8-4, April 10, 1967, by United Engineers & Constructors, Inc. for Westinghouse Electric Corporation for Indian Point Generating Station – Unit No. 2
11	Page 14 of specification for piping materials, Specification No. 9321-01-248-18 Part A, July 29, 1966, Revision 6A, September 1, 1990.

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Figure 1- View of pipe coating as observed in the excavation by Entergy Staff
This photograph was provided to SI by Entergy staff. It was taken before the pipe sample was removed. Note wrinkling of the coating typical of soil stress. (Soil stress refers to distortion of external pipe coatings of this type. The distortion is typically caused by relative movement of the pipe and soil resulting from pipe expansion and contraction, soil settlement, or other events.) Arrows point to examples of angular rocks in the backfill.

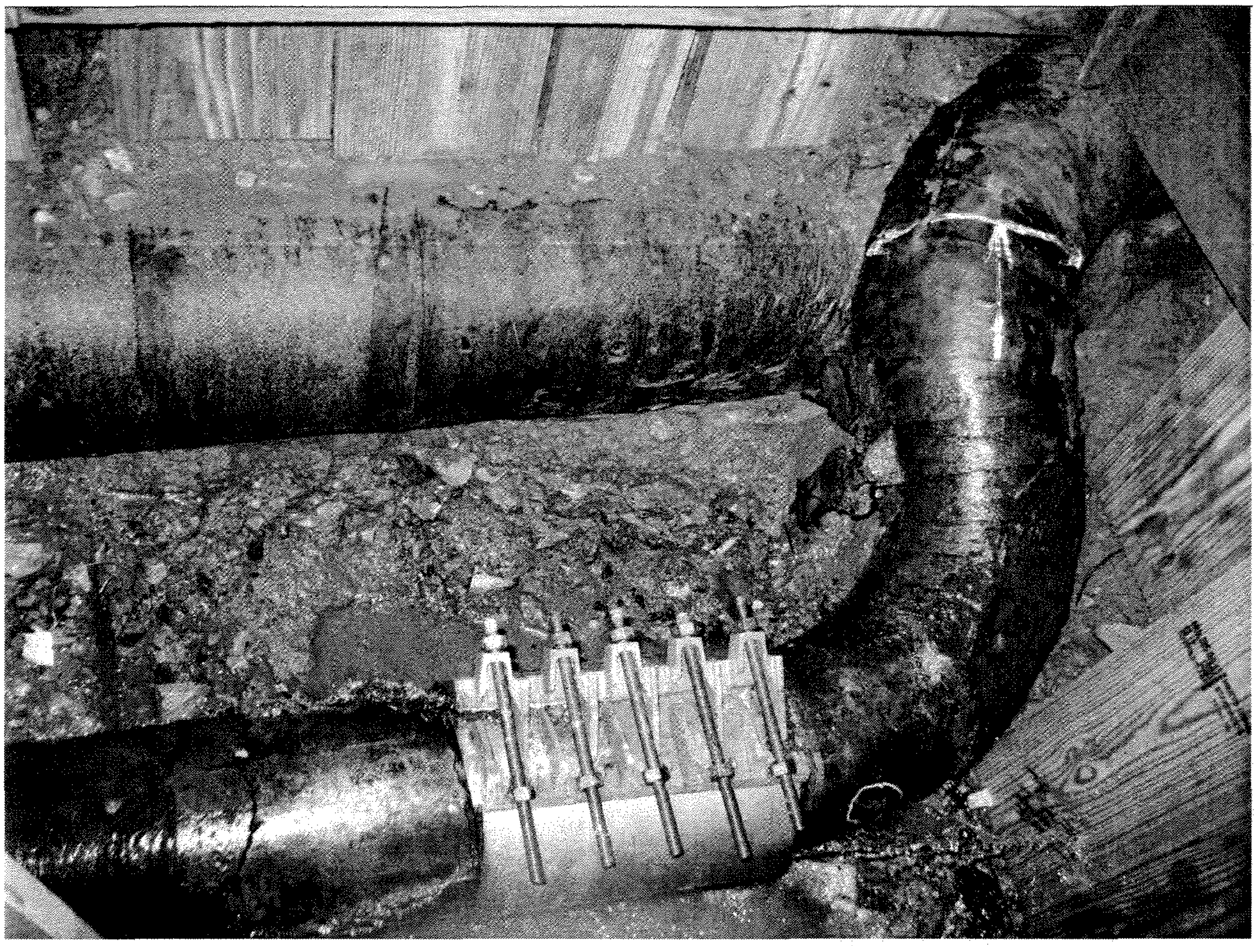

Figure 2 - Photograph of pipe in the excavation before removal of the pipe sample. This photograph was provided to SI by Entergy staff. A leak clamp has been applied to the area of the leak. The white arrow and lines at upper right indicate the limits of coating that was to be removed during the process of replacing the segment of leaking pipe. See next figure for detail of rocks in the backfill to the upper left of the clamp.

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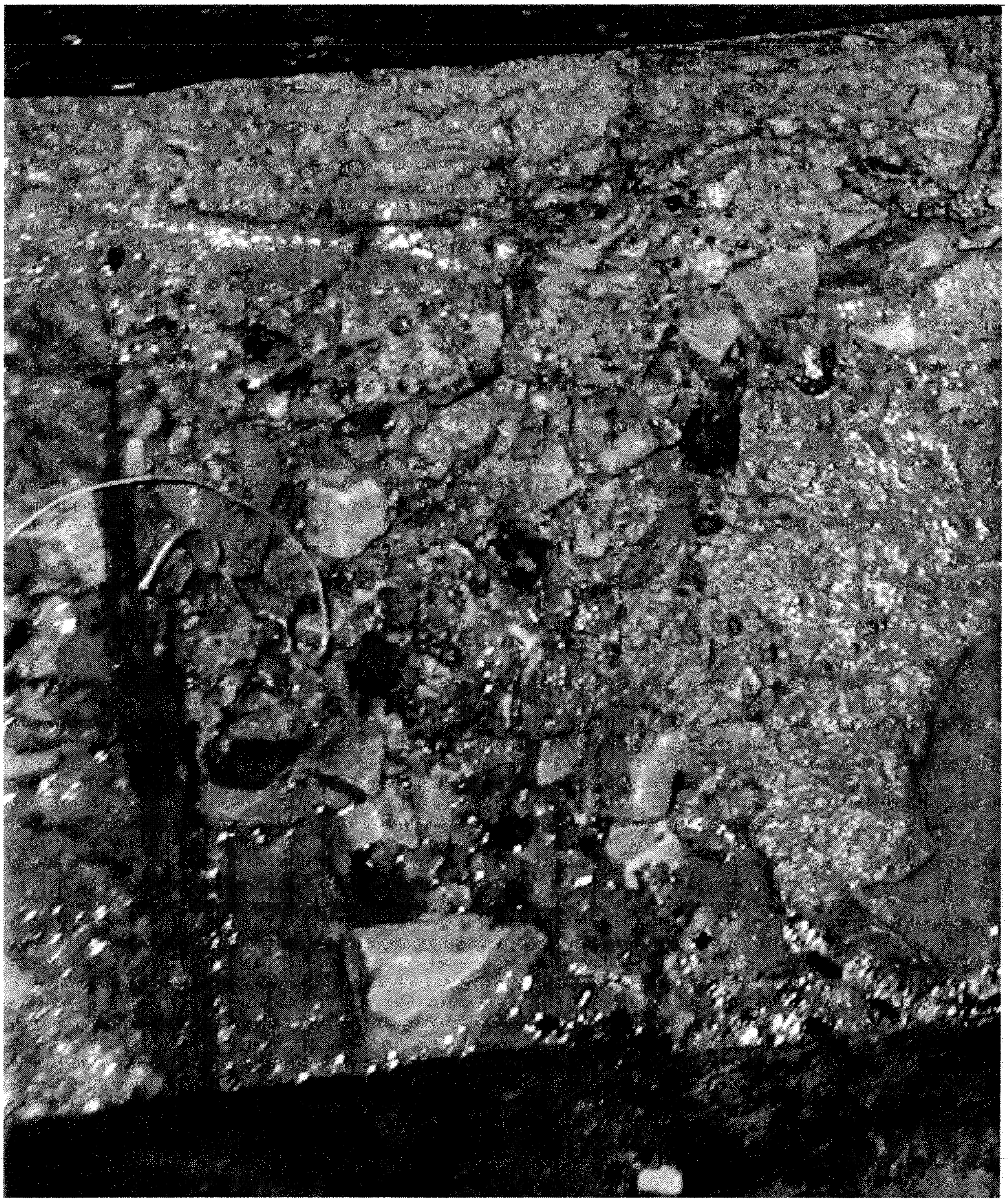

Figure 3 - Detail of previous figure showing angular rocks in the backfill.

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Analysis and Results

The analysis tasks included the following:

- Detailed receipt inspection of the sample
- Detailed visual inspection of the outside diameter (OD) of the pipe for cracks, mechanical damage, thinning, corrosion product, etc.
- Visual examination of the inside surface of the pipe for evidence of features that might have influenced the failure
- Dimensional characterization from the OD
- Detailed corrosion mapping
- Metallography to determine the general microstructure and correlation between failure location and microstructure, proper microstructure, any anomalies
- EDS (energy dispersive spectroscopy) and XRD (x-ray diffraction) of corrosion products
- Bulk steel composition
- Tensile Properties of pipe and elbow

The significant findings are summarized below. Details of the results and relevant comments are included in the figures and tables that follow.

Visual Examination: The external coating had been removed and the external surfaces wire brushed and washed by site personnel prior to shipping. As a result, no soil or external coating was present when we received the sample. Some external corrosion product may have been removed by the washing process. The as-received condition of the pipe is illustrated in Figures 4 through 9. Segments removed for further analysis are illustrated in Figure 10. Photographs of manufacturer's markings are illustrated in Figures 11 through 14.

External corrosion on the straight pipe generally consisted of deep isolated pits surrounded by surfaces that were completely uncorroded. The pattern of corrosion was consistent with isolated breaks in the coating. The observed corrosion is mapped in Figure 15. Photographs illustrating representative areas of the corrosion are included in Figures 16 though 32.

The external corrosion on the elbow was more widespread and included relatively large areas of more generalized corrosion. This corrosion pattern was more characteristic of less effective performance of the external coating, perhaps as a result of the difficulty in producing a good wrap pattern when coating irregular shapes such as elbows and other fittings.

In both the elbow and the pipe the morphology of the metal loss included features often associated with MIC including tunneling, striations, overlapping cup-shaped pits, and steep sided pits that sometimes had metal loss that undercut the surface of the pipe. However, similar corrosion patterns can also be produced by abiotic corrosion mechanisms.

The internal corrosion consisted of very shallow scattered pits in the elbow and more widespread, generalized corrosion in the pipe. The appearance of the corrosion is illustrated in Figures 33 through 37. Nothing observed on the inside surface of the pipe would have contributed to this leak.

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The girth weld appeared to be of good workmanship with no significant visible flaws from anything other than corrosion.

Ultrasonic Thickness Surveys and Corrosion Mapping: Ultrasonic thickness data provided by Entergy were spot checked and then supplemented with additional measurements. The supplemental measurements were located around the circumference of the sample at four locations, including near the end of the pipe, the end of the elbow, and on each side of the girth weld. No unexpected results were obtained and the SI data were similar to measurements made by Entergy staff at the corresponding locations.

Visible areas of external corrosion were measured to record the maximum axial length and circumferential width and maximum depth of each area. On the straight pipe, the measurements were made using a digital pit depth gage with a resolution of 0.0005 inches. On the elbow where the pit depth gage and bridging bar could not be used, the pit profile was replicated using a contour gage and the contour was traced. The depth of the pit as indicated by the trace was measured using a magnifying glass and a machinist's scale with a resolution of 0.01 inches. Prior comparisons of this method with a conventional pit depth gage show that the contour gage measurements are typically accurate to about 0.010 inches.

Corrosion Product Analysis: The corrosion product on the external surface was relatively soft and friable and was generally nonmagnetic or very weakly ferromagnetic. The corrosion products did not extend above the surface of the pipe, but pits were either completely or partially filled with corrosion product in most cases. Analysis by XRD showed that the external corrosion products consisted primarily of iron carbonate (siderite). EDS showed the presence of very little chloride and only small amounts of sulfur.

The corrosion product on the inside was very hard, tightly adherent, and strongly attracted to a magnet. The corrosion products resulted in distinct raised bumps above each small pit. Analysis by XRD showed that the corrosion product was composed of various iron oxides, including about 70% magnetite, which was likely responsible for the hard, adherent, ferromagnetic properties. Only small amounts of chlorine and sulfur were present.

Analysis of the Steel: The tensile properties of the pipe and elbow were normal. The chemical composition of the elbow met the specification. The chemical composition of the pipe deviated from the ASTM A106 requirement that the steel contain at least 0.1% silicon. Two samples of the steel pipe both were found to contain 0.02% silicon, which meets the requirements of both API 5L grade B pipe and ASTM A53 grade B seamless pipe. It is unlikely that the deviation influenced the external corrosion. However, we have seen other cases in which the silicon killed steels appeared to be slightly more resistant to some forms of internal corrosion. The small difference in composition may explain the differences in the patterns of internal corrosion observed between the elbow and the pipe (i.e., general corrosion vs. pitting).

Microstructural Analysis: The metallographic cross sections of the pipe, elbow, and girth weld showed no metallurgical anomalies. All microstructures were as expected. The pipe and the elbow both consisted of fine pearlite and proeutectoid ferrite phases, as is typical for hot worked

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mild steel. The cross sections showed that the mill scale (magnetite) on the outside surface of the pipe was intact except in areas of corrosion pits, indicating that the surface was not prepared by abrasive blasting prior to coating. The microstructures are illustrated in Figures 40-48. See the figures for explanation of the illustrated features.

Determination of Corrosion Mechanism: The determination of the likely mechanism for the external corrosion was based mainly upon the characteristics of the corrosion product and the morphology of the corrosion. As noted above, the external corrosion product is virtually all iron carbonate. Iron carbonate is most commonly associated with corrosion resulting from exposure of steel to wet CO_2 . However, several sources discuss the formation of iron carbonate in fresh and salt waters where CO_2 corrosion is unlikely[2 3 4 5]. The references cite the finding of siderite among fresh water and salt water corrosion products but do not describe the morphology of the metal loss associated with the siderite or the corrosion rates related to its formation. Reference 2 relates the formation of siderite to near neutral pH conditions (i.e., about pH 7.2 to 9.4) in which some alkalinity is present, and oxygen is either absent or in which the oxidation of ferrous iron Fe(II) to Fe(III) is kinetically inhibited. Examples of oxidation inhibitors that would favor the formation of siderite include natural organic matter and calcium. The same reference, though, describes siderite as a relatively protective corrosion product, relative to the protectiveness of other corrosion products.

Siderite has also been shown to be related to microbiological processes[6 7 8], although it is less commonly cited than some other corrosion products as a MIC-related corrosion product in the corrosion literature.

[2] Wilson, B.M., Johnson, D.L., et.al., "Corrosion Studies on the USS Arizona with Application to a Japanese Midget Submarine" TMS website at http://www.tms.org/pubs/journals/jom/0710/wilson-0710.html
[3] AWWA Research Foundation "Internal Corrosion of Water Distribution Systems", ISBN 0898677599, published by American Water Works Association, 1996
[4] McNeill, L.S., Edwards, M. "Review of Iron Pipe Corrosion in Drinking Water Distribution Systems"
[5] Cook, D.C., Peterson, C. E., "Corrosion of Submerged Artifacts and the Conservation of the USS Monitor", AIP Conference Proceedings, Journal Vol 765, Issue 1,International Symposium on the Industrial Applications of the Mossbauer Effect, Madrid, Spain, May 2006
[6] Zhang, C.L., Horita, J, et. al., "Temperature-Dependant Oxygen and Carbon Isotope Fractionations of Biogenic Siderite" downloaded from http://www.sciencedirect.com
[7] Weber, K. A., Picardal, F.W., Roden, E.E. "Microbially Catalyzed Nitrate Dependant Oxidation of Biogenic Solid-Phase Fe(II) Compounds" *Environmental Science & Technology*, 2001, vol. 35,No. 8, pp 1644-1650.
[8] Mattiesen, H., Hilbert, L.R., Gregory, D.J., "Siderite as a Corrosion Porduct on Archaeological Iron From a Waterlogged Environment" *Studies in Conservation,* vol 48., 2003, pp 183-194

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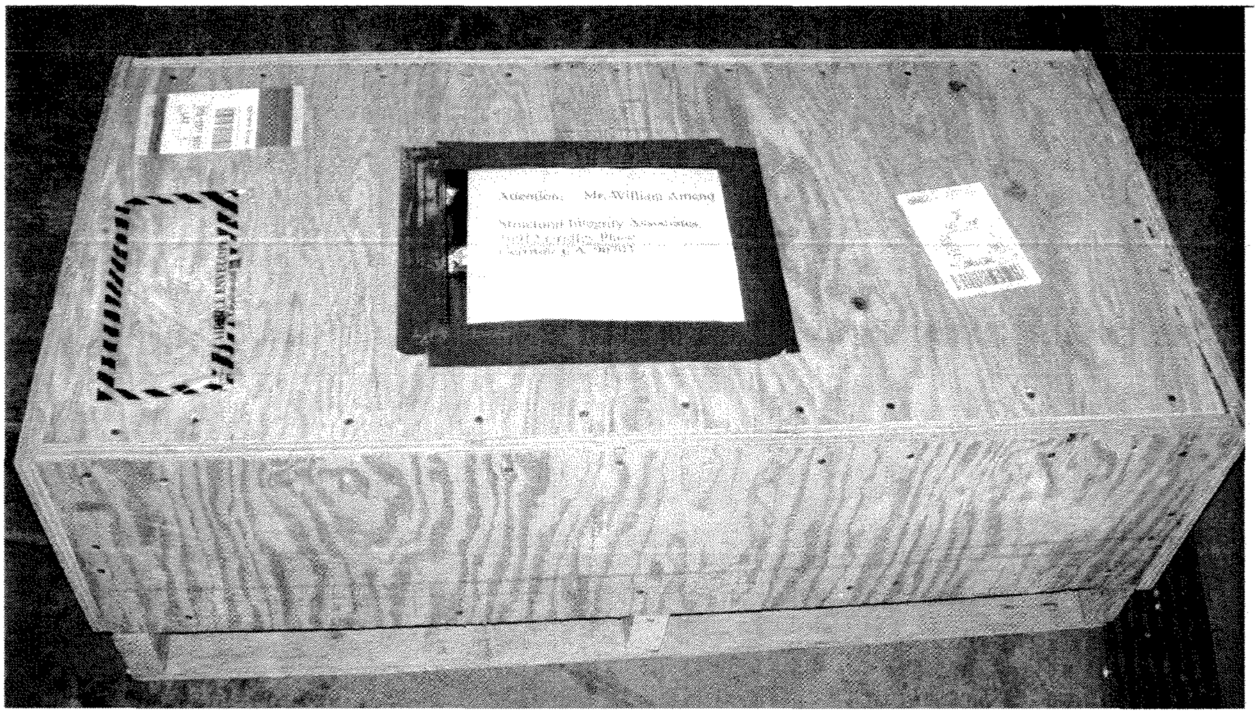

Figure 4 - Shipping container for pipe sample, as-received on March 23, 2009

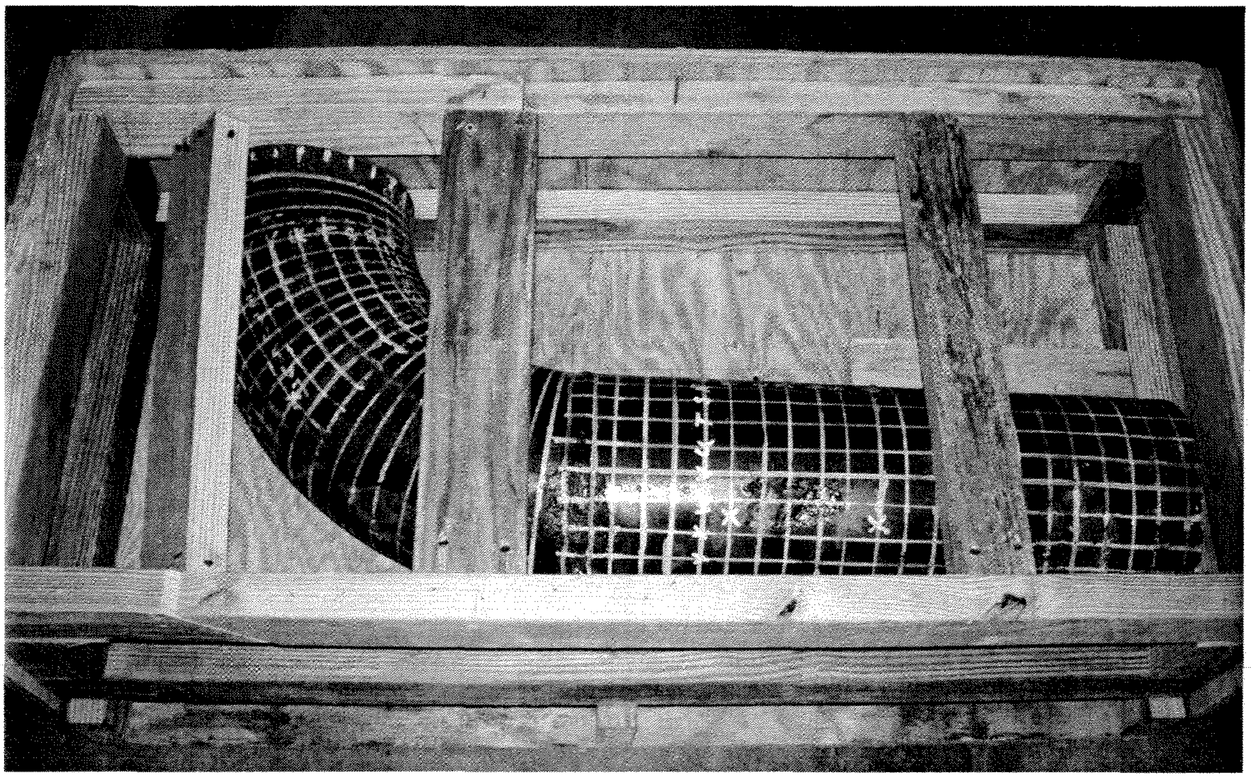

Figure 5 – Pipe sample as-received in the shipping container.

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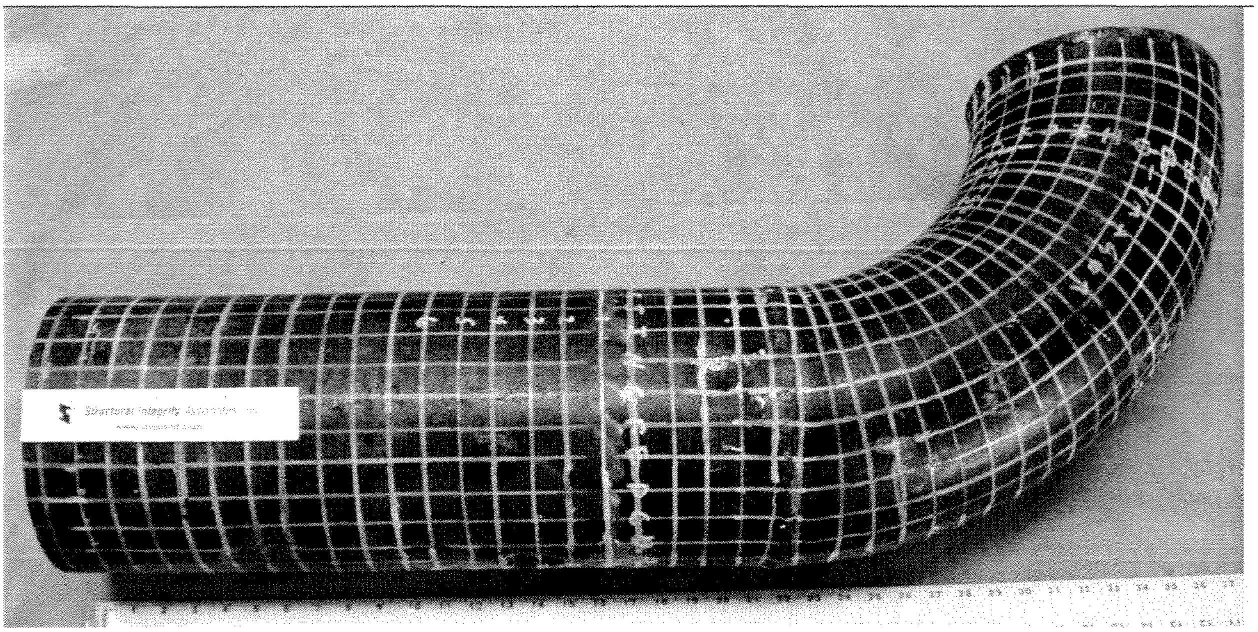
Figure 6 - Pipe sample as received, view 1

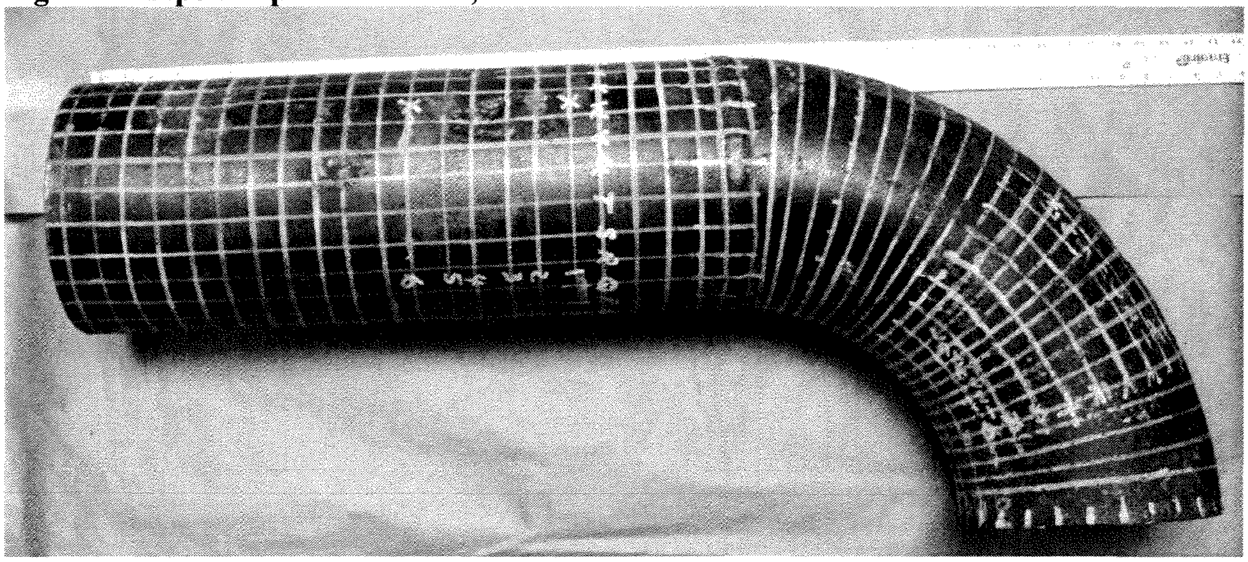
Figure 7 - Pipe sample, as-received view 2

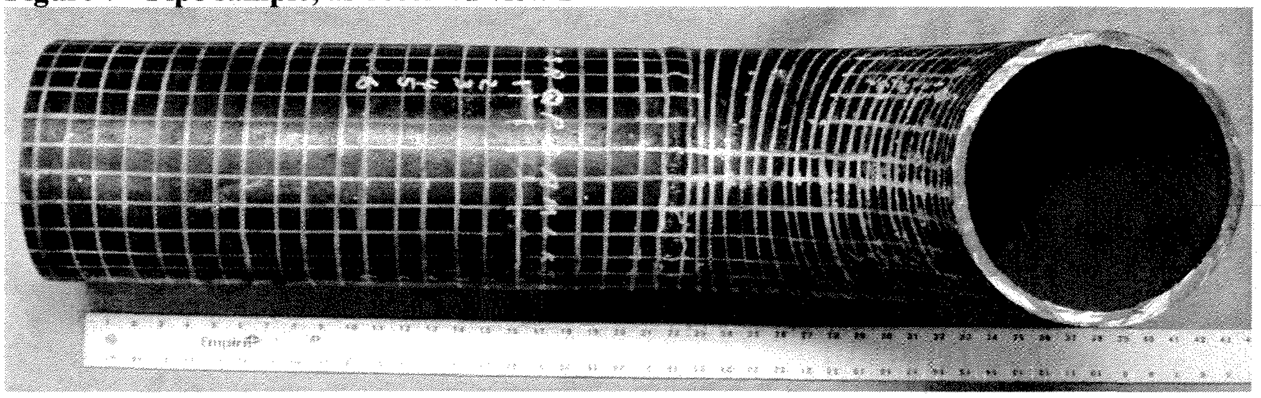
Figure 8 - Pipe sample, as-received, view 3

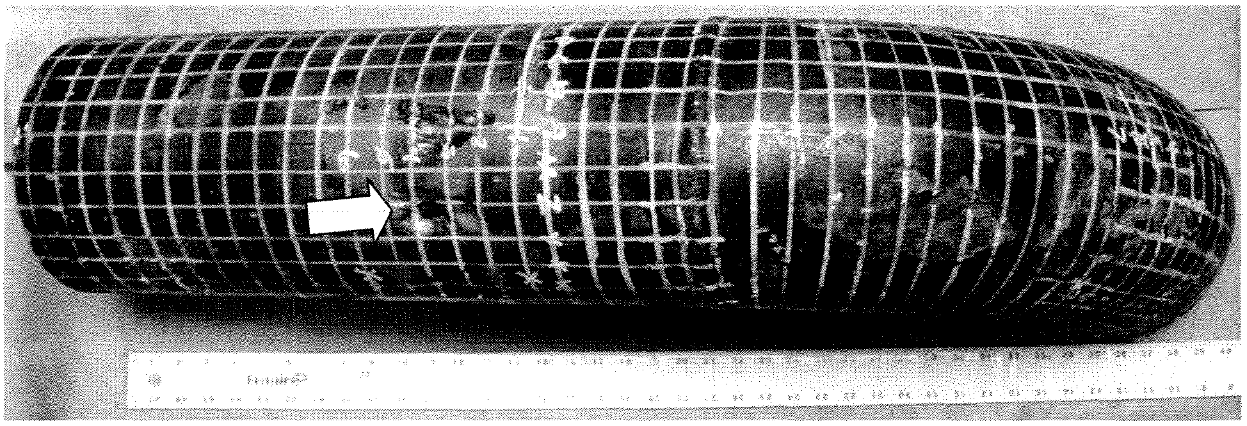

Figure 9 - Pipe sample, as-received , view 4. Arrow points to location of leak

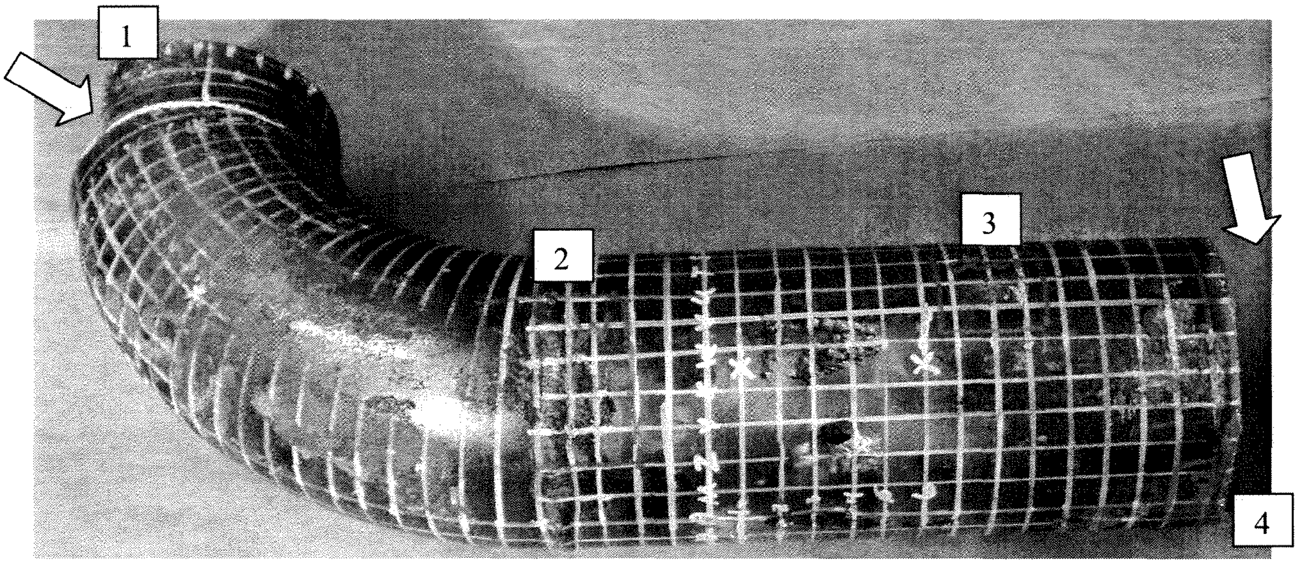

Figure 10 - Pipe sample marked with red boxes to show locations of samples removed for further analysis

1. Elbow sample with ID corrosion for metallographic examination,
2. Girth weld sample for metallographic examination,
3. External corrosion pit with internal corrosion on pipe for metallographic examination and EDS analysis of the corrosion product
4. Second sample of pipe for metallographic examination (investigation of possible ERW seam).

Segments at arrows at ends of the sample were previously removed for tensile testing and analysis of steel composition.

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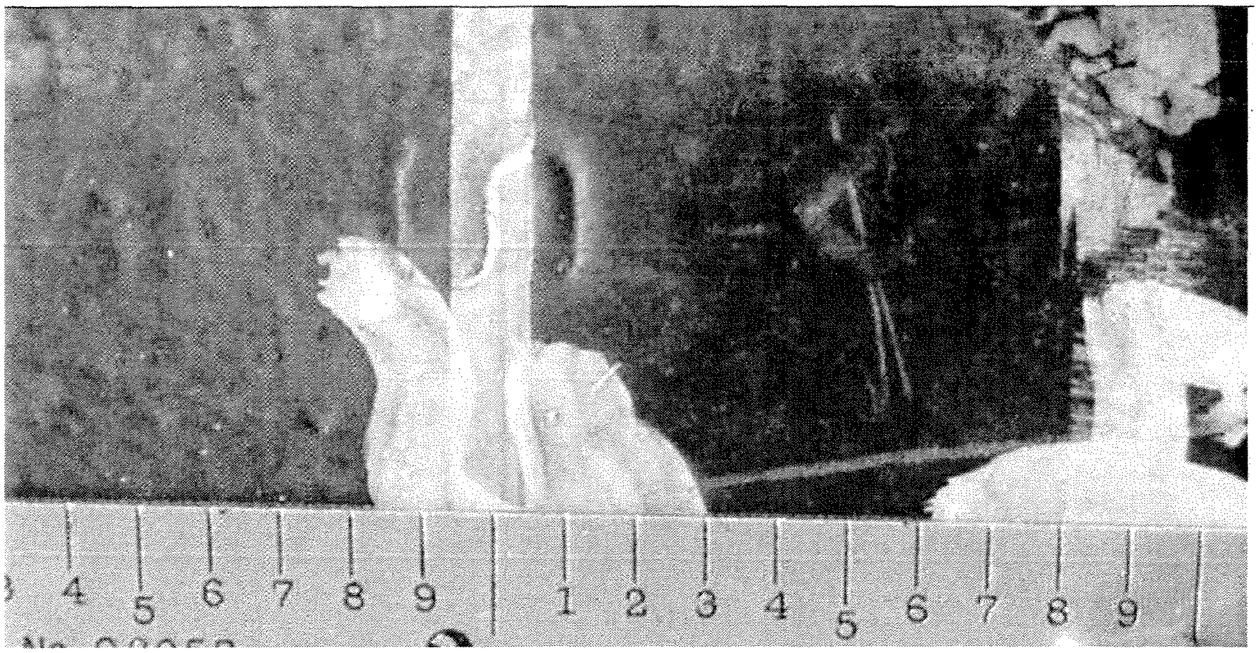

Figure 11 - "YS" stamp mark on pipe.
The stamp marks indicate that this pipe is pipe manufactured by Youngstown Steel. At this location the stamps have been partially polished away by erosion from the nearby leak (in this pipe).

Figure 12 - API monogram stamp mark on pipe.
Monogram indicates that pipe met requirements of API specification 5L. It may have also been manufactured to meet ASTM specifications. Grids outlined by white lines are approximately 1" x 1".

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Figure 13 - Manufacturer's stamp marks on the neutral axis of the elbow.
See next figure for detail of the stamp mark after cleaning.

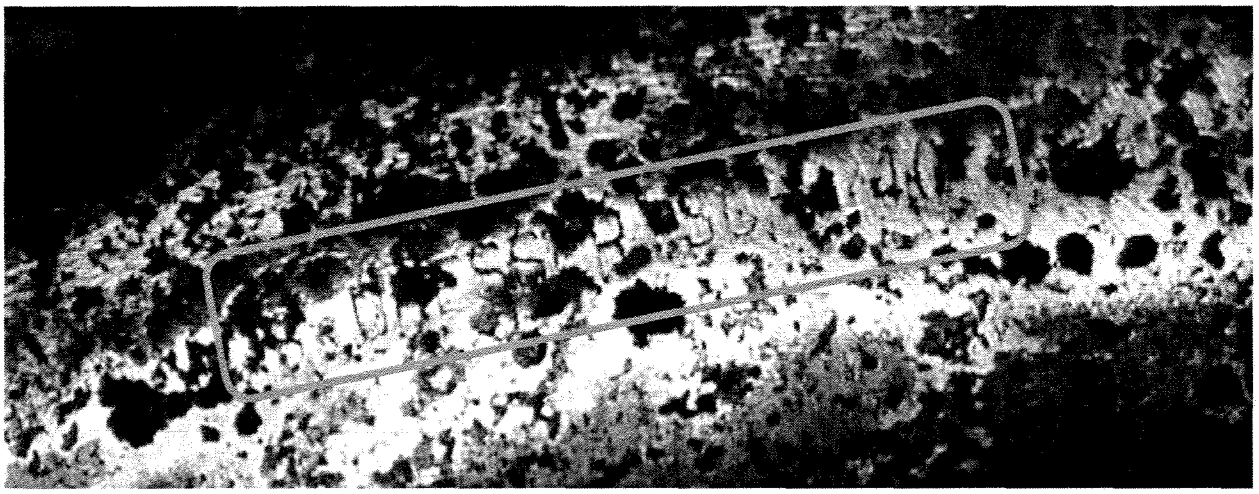

Figure 14 - Manufacturer's stamp mark after light abrasion with sandpaper.
The stamp marks on the neutral axis of the elbow identify it as an 8" schedule 40 fitting manufactured by Dresser. The grade of the fitting is obscured by corrosion.

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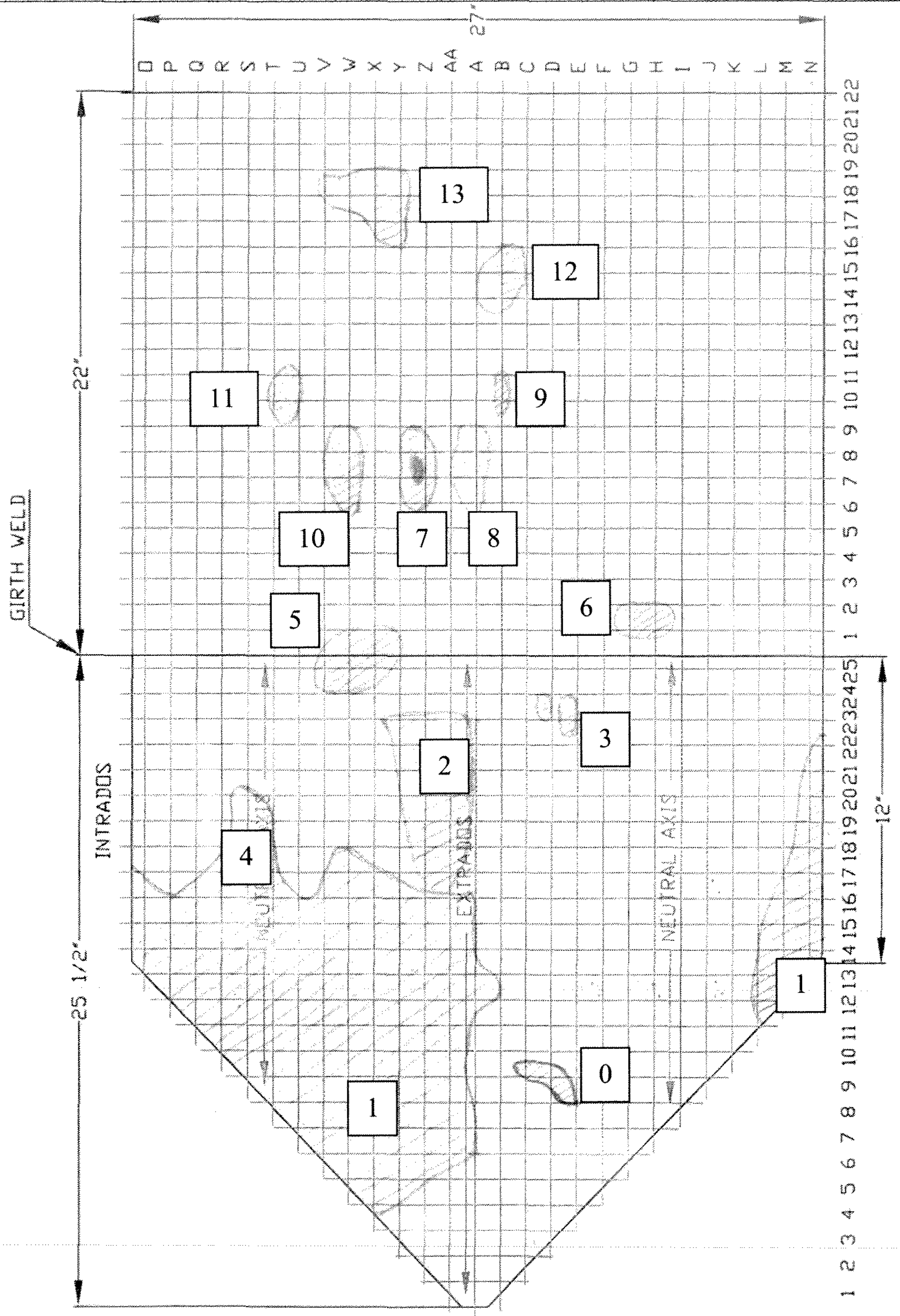

Figure 15 – Map of external corrosion
Major areas of corrosion are sketched and numbered. The axial grid lines (marked A, B, C, etc.) are as marked by Entergy. The leak is at location #7. See Table 3 for additional details

Table 3 – Dimensions of Major Areas of Corrosion

Area (see Fig. 15)	Maximum length (inch)	Maximum depth (inch)	Maximum width (inch)	CSA (%) (Note 1)	Related Figures
0	1.7	0.11	2.6	2.3	16
1	9.7	0.20	19	30.2 (note 2)	17, 18
2	7	0.17	3.5	4.7	-
3	1.2	0.09	0.75	0.5	-
4	See Area 1data, see note 3				19, 20
5	2.8	0.09	3.2	2.3	21, 22, 38-41
6	1.8	0.276	2	4.4	23
7	2.9	Hole (leak)	1.5	3.8	24,26
8	3.6	0.247	1.4	2.7	24
9	1.8	0.103	0.5	0.4	24, 25
10	3.4	0.184	1.8	2.6	26
11	2.3	See note 4	1.3	NA	27, 28
12	2.4	0.251	2	4.0	-
13	3.2	0.171	3	4.1	29-32

Notes:

1) The %CSA represents the portion of the pipe wall area (as measured in a circumferential cross section through the pipe) that is affected by the metal loss. It relates to the detectability of the corrosion using guided wave UT inspection methods. Larger %CSA values typically represent flaws that are more easily detectable. The %CSA (cross sectional area) of each significant flaw is approximated by the following equation:
   % CSA =100 x (2/3 x flaw depth x flaw width)/(pi x outside radius^2 – pi x inside radius^2)
   For the purpose of detectablility by use of guided wave UT inspection ,the %CSA separate flaw areas located in the same circumferential plane may be combined to estimate the total %CSA, as shown below:

Flaw Areas in a shared circumferential plane	Total % CSA
0, 1	32.5
2, 4	34.9
2, 3	5.2
5, 6	6.7
7, 8, 10	9.1
9, 11	>0.4 (see note 4)

2) The majority of the corrosion was shallow, therefore the equation used to estimate %CSA is overestimating the area of metal loss
3) This area is continuous with Area 1
4) This pit was metallographically cross sectioned with corrosion product intact. Pit depth could not be measured and cross section may not have revealed deepest point

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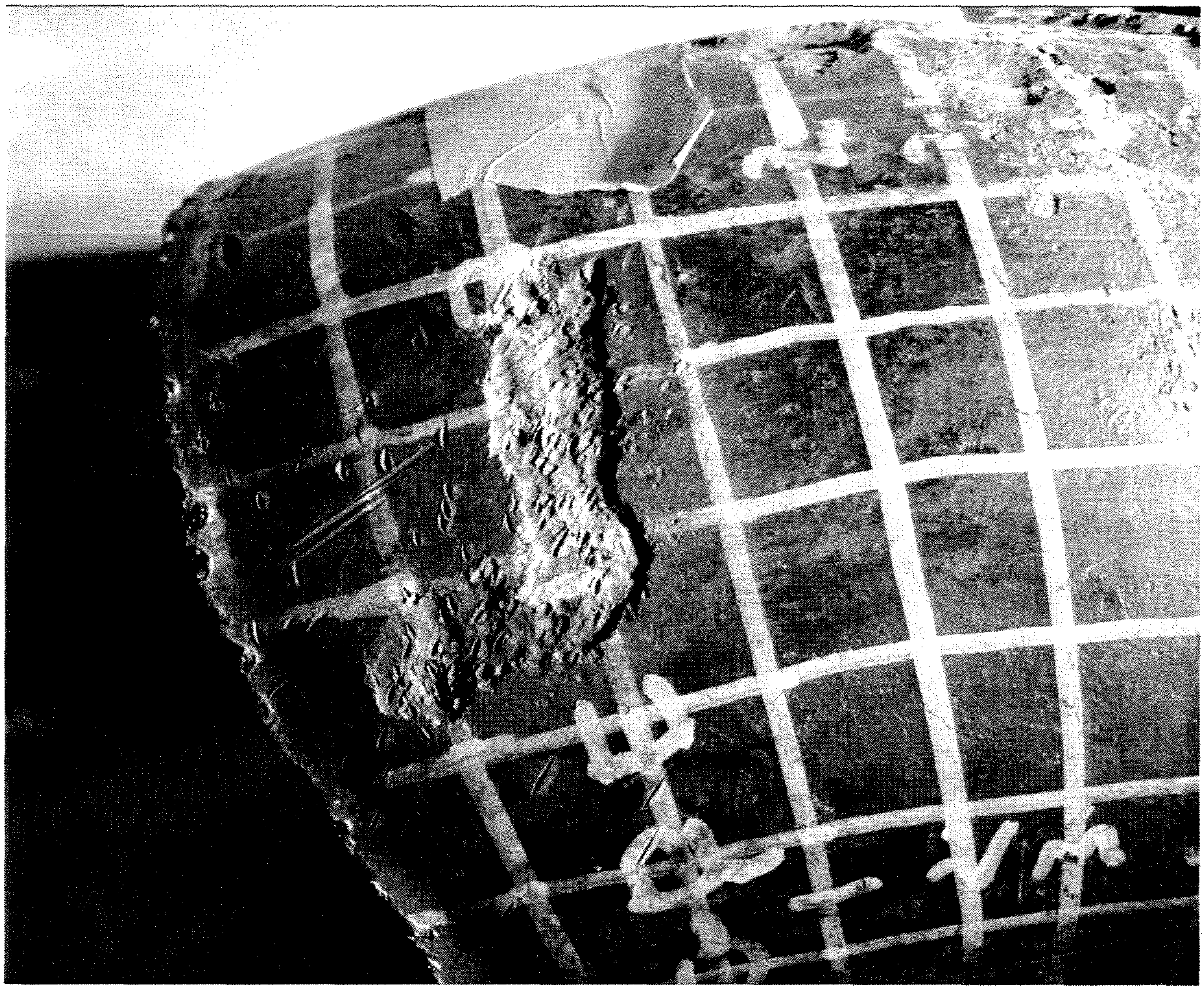

Figure 16 - External corrosion on elbow (as-received condition) designated Area 0
Note the absence of any corrosion surrounding the "L" shaped pit.

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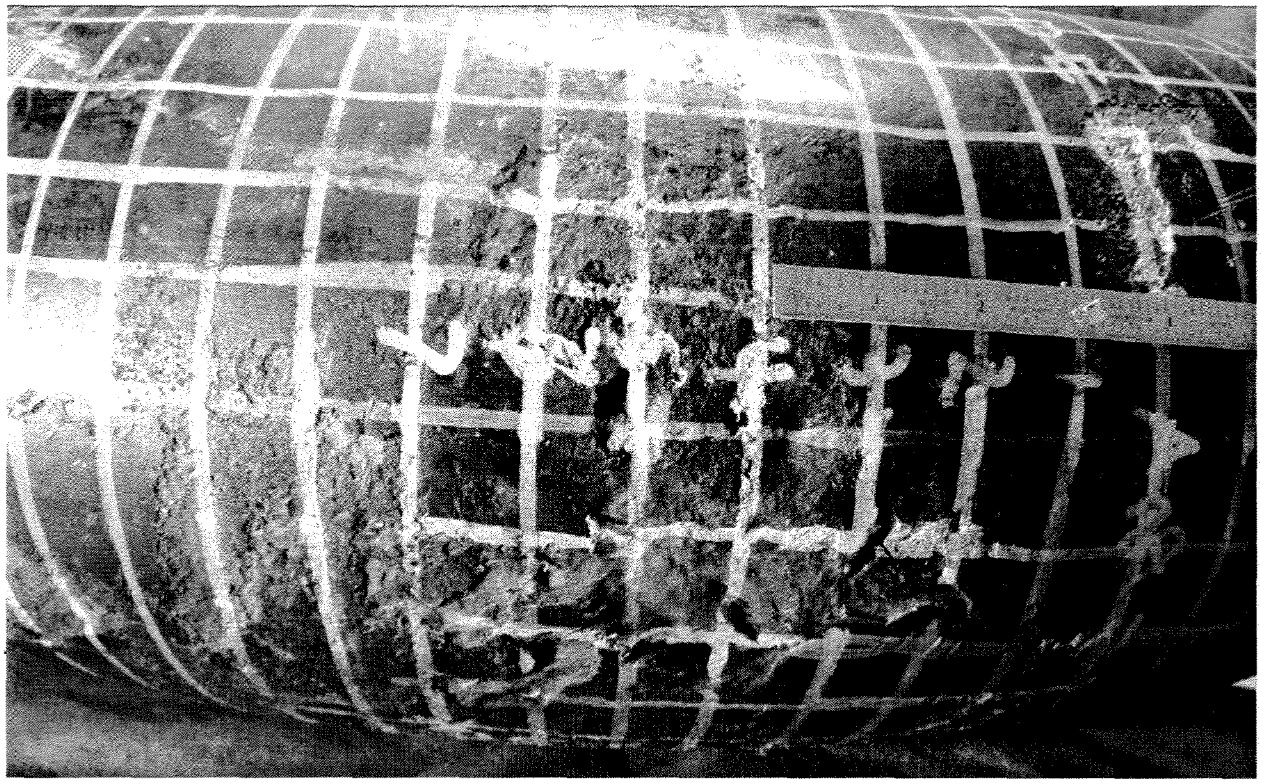

Figure 17 – External corrosion on the extrados of the elbow, as-received; designated Area 1

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Figure 18-- Extrados of ell after cleaning, Area 1.
Note extensive general corrosion compared to the straight pipe. A circumferential band was masked off to prevent loss of the grid line identifications

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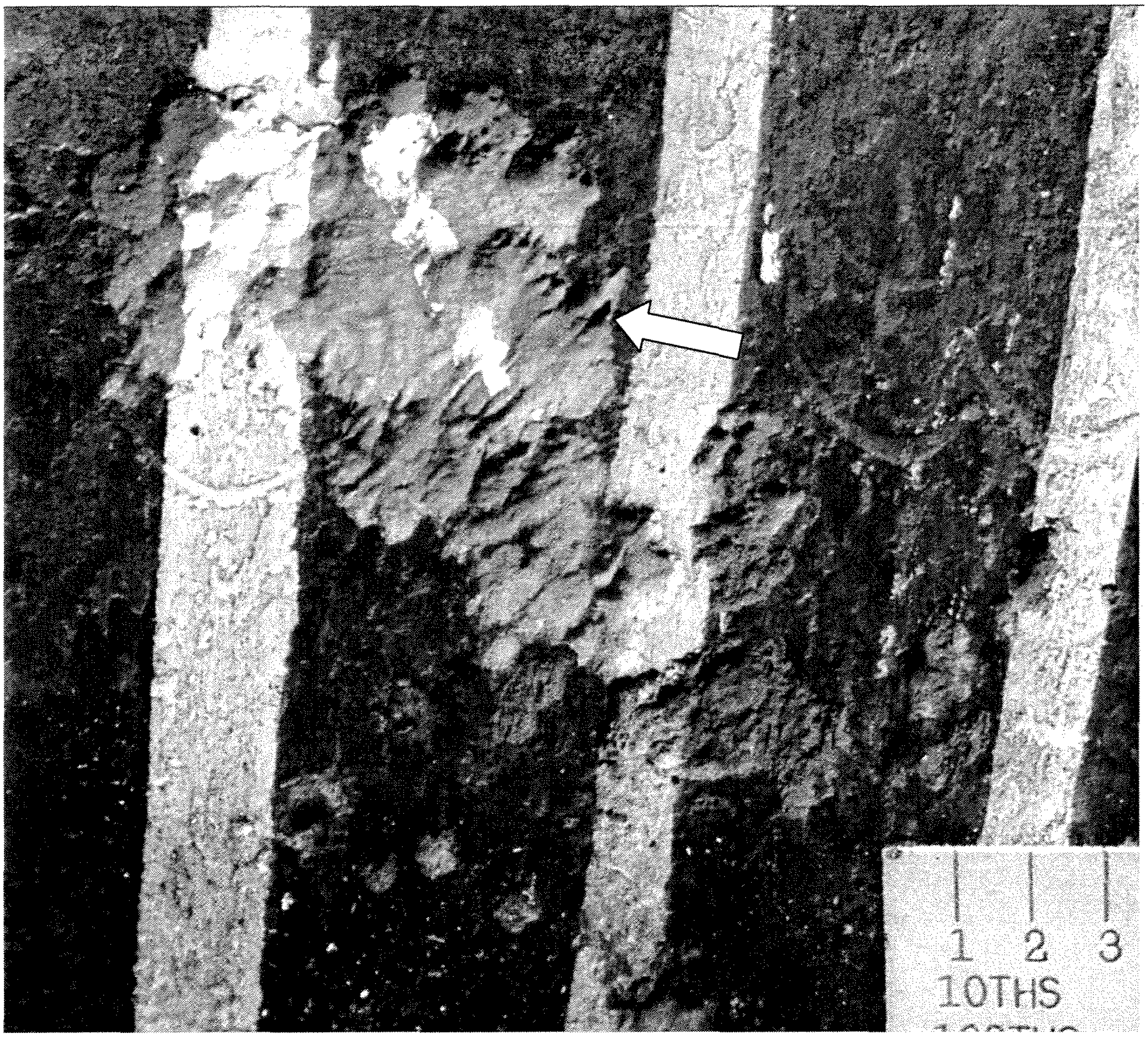

Figure 19 – Detail of corrosion in Area 4, Location 1
Note sharp edges of pits and tunnel like features (arrow points to one example of tunneling).

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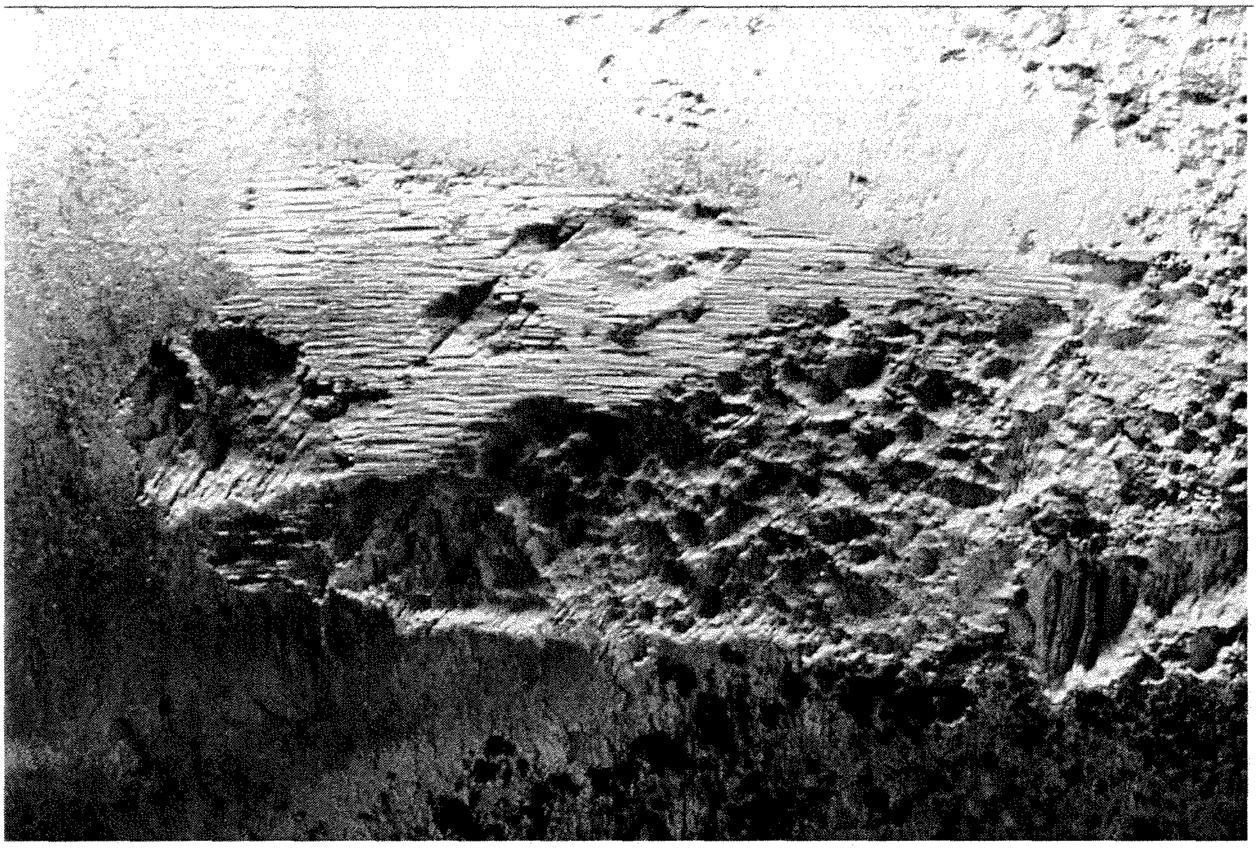

Figure 20 - Area of Area 4, Location 2 after cleaning by glass bead blasting
Note scrape marks. These scrape marks appeared to have discoloration and oxidation comparable to the surrounding uncorroded pipe surface suggesting they may have been formed either during the installation process, or prior to the pipe coating process. If they were formed after coating, the coating would have been damaged and exposed the scraped area to the soil. As a result, the scrape would have been eliminated by subsequent corrosion. The striations are elongated features oriented from lower left to upper right in the round pit at upper left.

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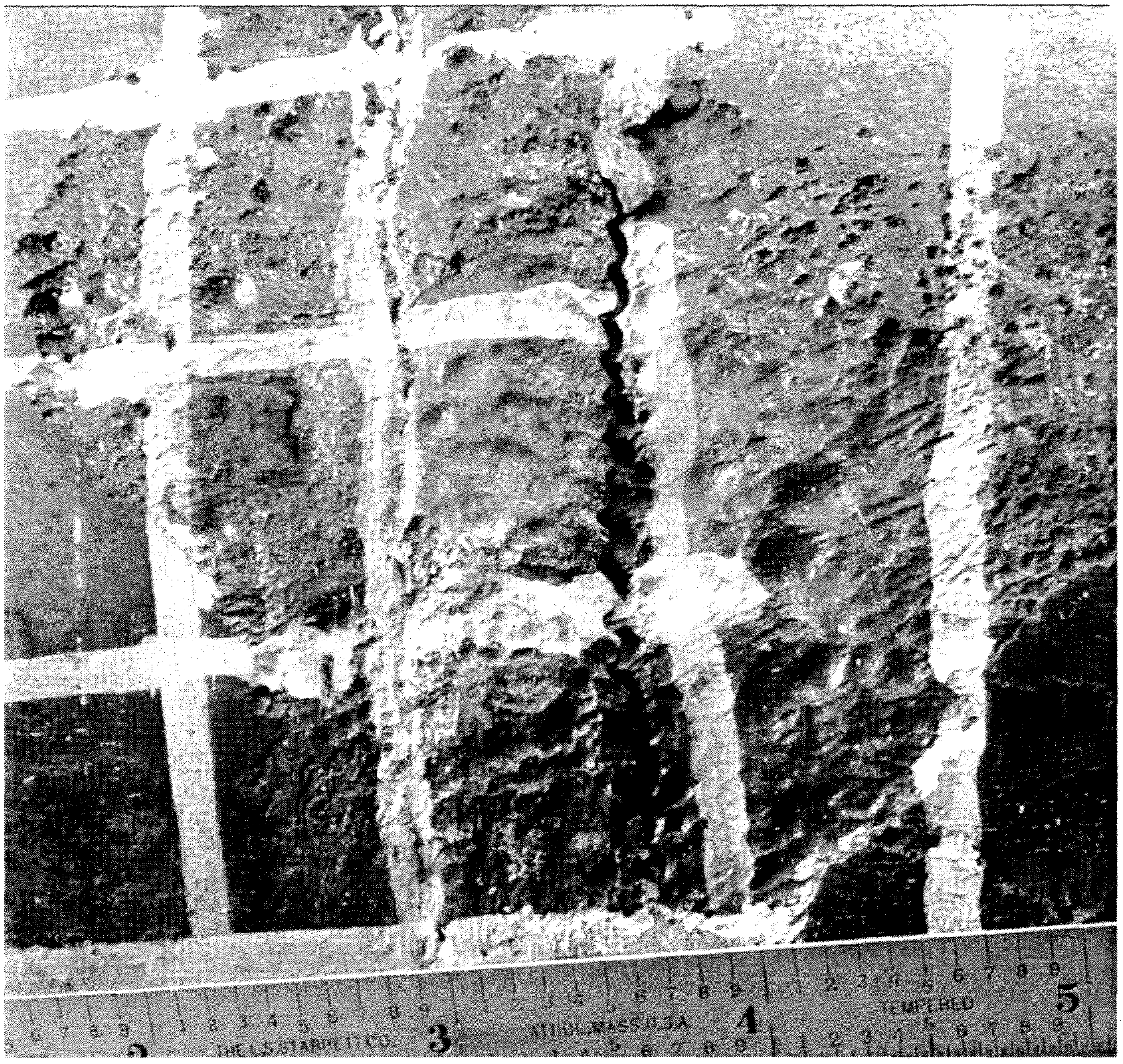

Figure 21 – Detail of corrosion on girth weld in the location designated Area 5.
Note corrosion undercutting the toe of the weld and striations in adjacent corrosion on the elbow. The striations are short linear features oriented about 25 degrees off the longitudinal axis of the pipe and are most visible to the right of the weld

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Figure 22 – Second view showing detail of the corrosion undercutting the toe of the weld

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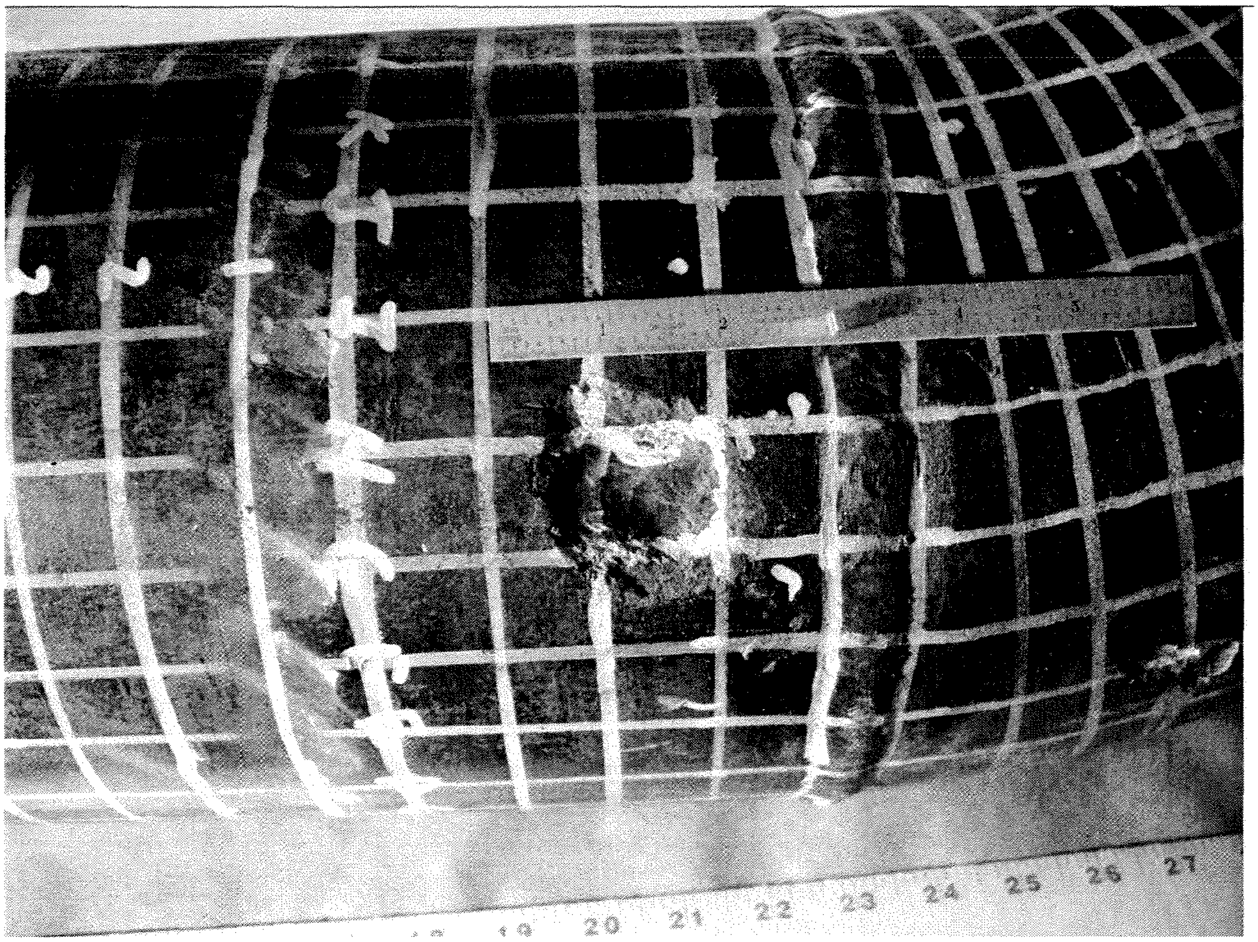

Figure 23 – External corrosion on the pipe (as-received condition), designated Area 6. Note absence of corrosion around this pit.

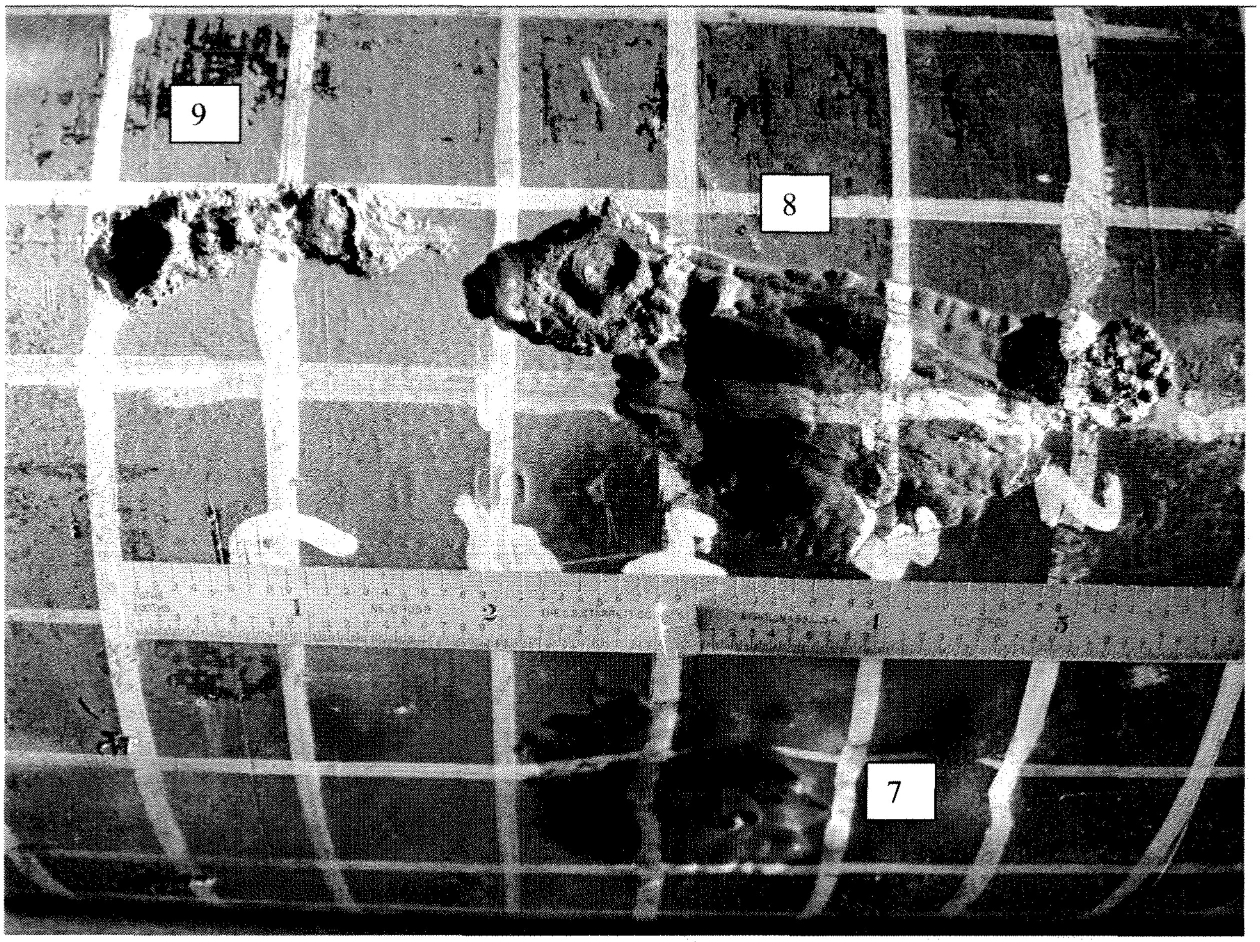

Figure 24 – Outside surface of pipe (as received) showing leak and two other areas of corrosion in addition to identifying "YS" and "API" stamp marks. Areas designated 7, 8, and 9

A very subtle feature that appeared to be an ERW seam runs horizontally through the "YS" stamp mark. Youngstown Steel manufactured both seamless pipe and ERW pipe in this size range. Only the seamless pipe could have met the requirements of ASTM A106. Subsequent metallographic examination of the location showed no microstructural evidence of a seam and the seam-like feature may be the remnants of the embossing wheel that produced the "YS" stamp during the manufacturing process of seamless pipe. The area surrounding the leak (Area 7) was eroded and polished as a result of turbulent water in the area of the leak. In comparison, areas of metal loss a few inches or more from the leak (i.e., see areas 8 and 9) have irregular topographies typical of corrosion that has not been modified by erosion.

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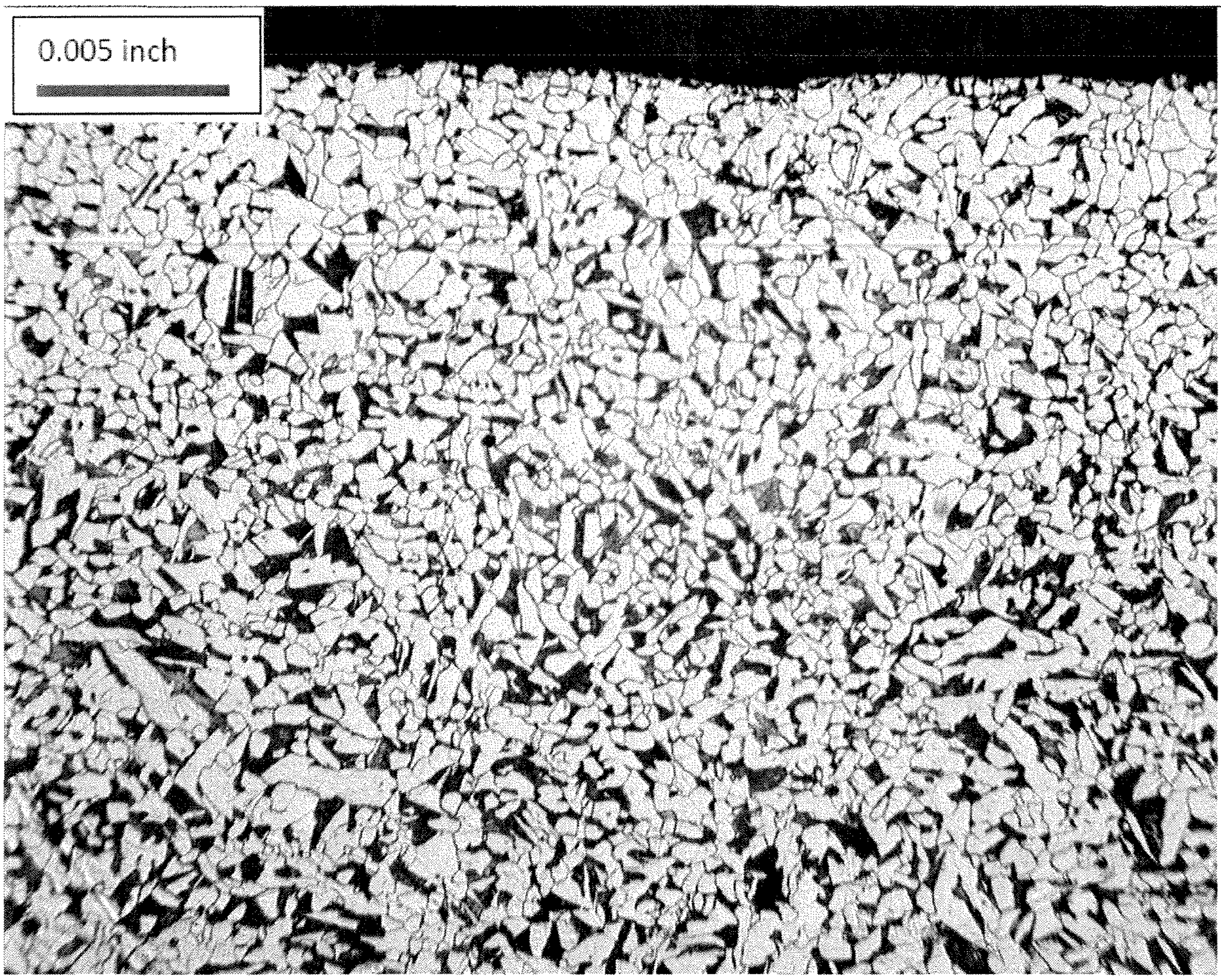

Figure 46 - Microstructure of pipe at outside surface.
There is no external corrosion at this location. The outside surface is at the top of the figure.

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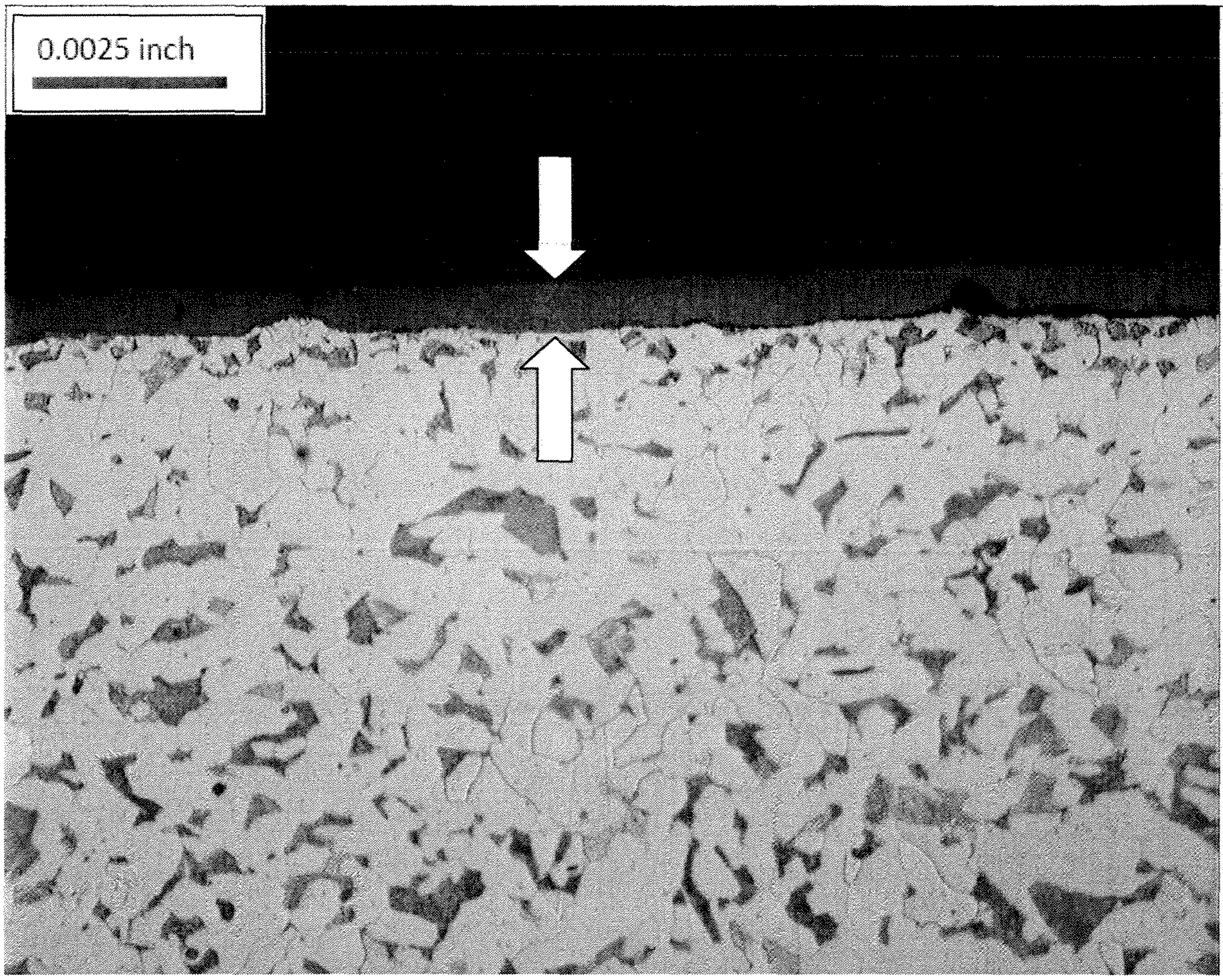

Figure 47 - Cross section through the pipe immediately adjacent to an external corrosion pit showing intact mill scale (between arrows)

The presence of intact mill scale indicates that there was no corrosion on this surface and that there was no surface preparation prior to external coating. A small amount of decarburization of the surface is present, as expected for this type of steel product.

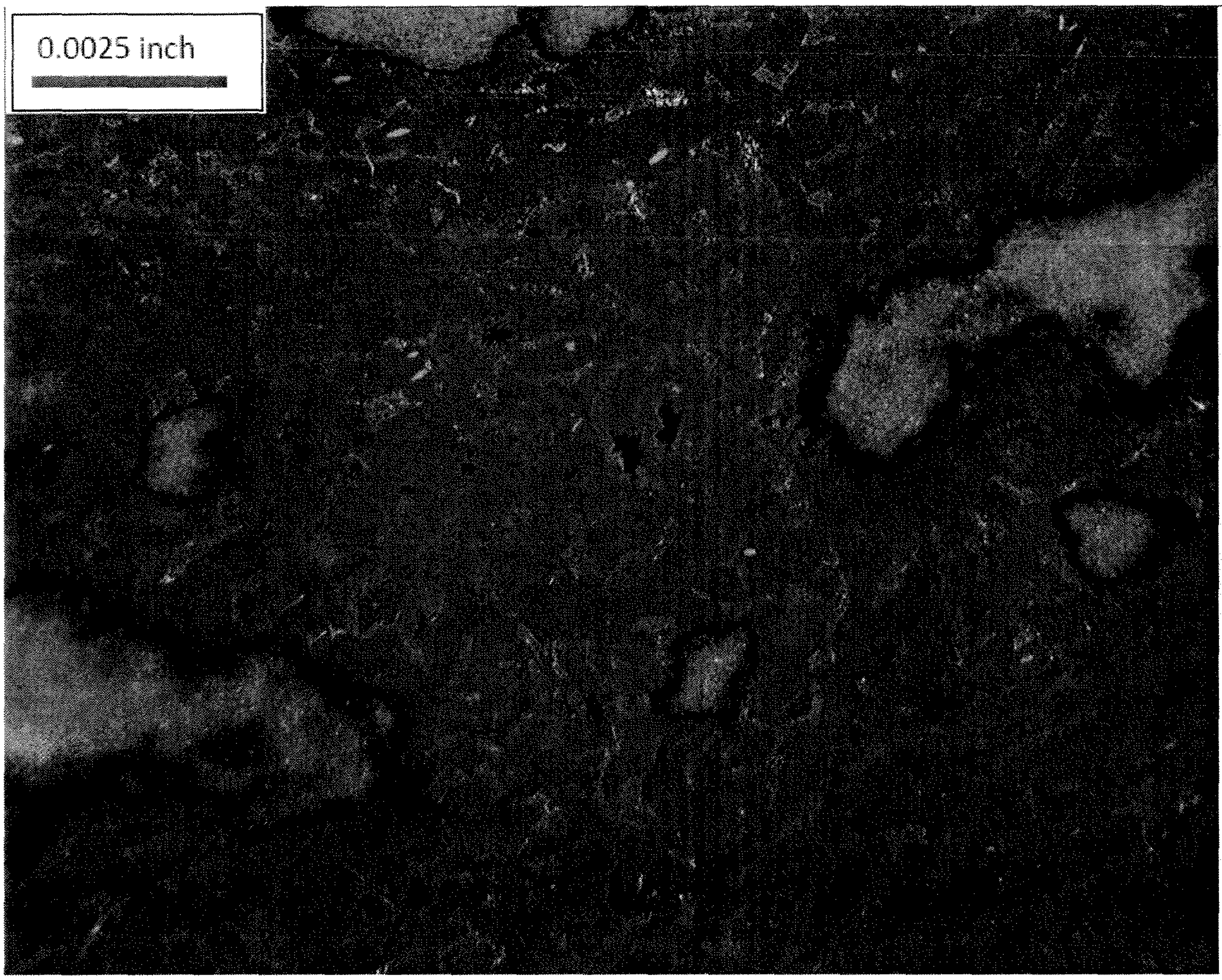

Figure 48- Detail of corrosion product in a pit on the outside of the pipe
The corrosion has preferentially corroded the proeutectoid ferrite and the ferrite lamellae of the pearlite leaving the iron carbide constituent of the pearlite grains uncorroded. The resulting shiny irregular globular-shaped areas replicate in the corrosion product the size and shape of the original pearlite grains. This appearance is typical of iron carbonate corrosion products.

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Table 4 – Ultrasonic Thickness Measurements (inches)

Specified nominal wall thickness = 0.322 inch

Location Per Entergy Grid (note 1)			SI Data	Corresponding Entergy Data
Row	Row	Column		
Pipe	A	1	0.296	0.298
Pipe	D	3	0.300	0.303
Pipe	G	5	0.310	0.304
Pipe	M	6	0.319	0.321
Pipe	S	2	0.317	0.317
Pipe	V	4	0.322	0.322
Pipe	Z	1	0.290	0.278
Pipe	AA	6	0.311	0.312
Elbow	AA	1	0.363	0.368
Elbow	C	7	0.358	0.353
Elbow	F	4	0.339	0.330
Elbow	J	2	0.324	0.321
Elbow	O	6	0.334	0.333
Elbow	S	3	0.351	0.350
Elbow	W	5	0.388	0.384
Elbow	Z	3	0.350	0.354

Location (2-inch Circumferential Increments)	~1 inch From End of Pipe	~1 inch From Girth Weld, on Pipe Side	~1 inch From Girth Weld, on Elbow Side,	~1 inch From End of Elbow
1	0.301	0.290	0.359	0.385
2	0.328	0.290	0.353	0.340
3	0.327	0.311	0.341	0.346
4	0.330	0.316	0.328	0.335
5	0.337	0.324	0.331	
6	0.315	0.334	0.320	0.314
7	0.308	0.345	0.322	0.323
8	0.311	0.343	0.327	0.329
9	0.294	0.326	0.335	
10	0.290	0.327	0.330	
11		0.319	0.341	
12		0.304	0.357	

Note 1: Measurements by SI at grid locations were made approximately at the intersection of the grid lines. Small differences in measurements between SI and Entergy data may reflect small variations in the location of the transducers during measurements.

Table 5 - Chemical Composition of Pipe and Elbow

Element	Pipe, location 1 (%)	Pipe, location 2 (%)	Spec. ASTM A106 Gr. B (%)	Elbow (%)	Spec. ASTM A234 WPB (%)
Carbon	0.20	0.23	0.30 max	0.18	0.30 max
Manganese	0.67	0.69	0.29-1.06	0.62	0.29-1.06
Phosphorous	0.008	0.008	0.025 max	0.007	0.050 max
Sulfur	0.016	0.020	0.025 max	0.12	0.058 max
Silicon	0.02	0.02	0.10 min	0.18	0.10 min
Nickel	0.01	0.01	0.40 max	0.01	NA
Chromium	0.06	0.06	0.40 max	0.01	NA
Molybdenum	0.01	0.02	0.15 max	0.02	NA
Copper	0.02	0.02	0.4 max	0.01	NA
Aluminum	<0.01	<0.01	NA	<0.01	NA

Note: Specifications limits are per ASTM Volume 01.01, 1991 and may not be the same as the requirements that were in effect at the time of construction.

Table 6 - Mechanical Properties of Pipe and Elbow

Property	Pipe, location 1	Pipe location 2	ASTM A106 Gr. B	Elbow	ASTM A234 WPB
0.2% offset Yield Strength (ksi)	43.5	42.3	35.0 min.	39.5	35.0 min
Ultimate Tensile Strength (ksi)	65.8	66.9	60.0 min	62.1	60.0-85.0
% Elongation	31.2	35.8	26.5 min	35.1	20 min
% Reduction of Area	52.6	54.7	NA	54.6	NA

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Table 7 - Results of XRD Analysis of Corrosion Products

Sample	Fe_3O_4 Magnetite*	α-Fe_2O_3 hematite	α-FeOOH goethite	γ-FeOOH lepidocrocite	$FeCO_3$ siderite	$Fe_2(OH)_2CO_3$
Inside corrosion	~70 wt%	~5 wt%	~15 wt%	~5 wt%	~5 wt%	~5 wt%
Outside corrosion					Major	Minor

*most likely combined with maghemite γ-Fe_2O_3 (=decomposed magnetite)

Table 8 - Results of EDS Analysis of Outside Surface Corrosion Products

Element	Concentration in Bulk Deposit	Concentration at Interface with Steel	Units
O	32.2	30.2	wt.%
Si	1.2	0.2	wt.%
S	0.6	0.4	wt.%
Cl	0.1	ND	wt.%
Cr	0.2	0.1	wt.%
Mn	0.3	0.5	wt.%
Fe	60.7	64.4	wt.%

Table 9 – Typical Results of EDS Analysis of Inside Surface Corrosion

Element	Bulk Deposit Location 1	Bulk Deposit Location 2	Steel Interface Location 1	Steel Interface Location 2	Units
O	30	26.1	24.7	31.3	wt.%
Al	0.1	0.2			wt.%
Si	0.7	1.2	0.6	0.8	wt.%
P	0.2	0.12			wt.%
S	0.1	0.2	0.3	0.6	wt.%
Cl	0.1			0.7	wt.%
Cr	0.5	0.2		0.2	wt.%
Mn	0.2	0.3	0.3	0.2	wt.%
Fe	58.4	66.5	68.0	60.1	wt.%
Ni	0.2				wt.%
Cu	0.4	0.3			wt.%

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Summary

The leak in the 8" steel condensate piping was caused by external corrosion. Corrosion on the exterior of the pipe consisted of a large number of localized pits, rather than of widespread general corrosion. The surfaces around the pits on the straight pipe had no evidence at all of corrosion and the original mill scale (high temperature iron oxide) was intact, indicating that where the coating remains intact the pipe surfaces are adequately protected against corrosion. The external surfaces of the elbow had more widespread corrosion, although a few portions (less than half of the surface) still showed no evidence of external corrosion. The patterns of corrosion on the pipe are consistent with localized mechanical damage to the coating. The corrosion on the elbow was consistent with an imperfect coating resulting from the difficulties inherent in coating an irregular surface such as the elbow.

During and after the excavation process, Entergy staff observed that the backfill in the area of the pipe included debris and angular rocks. Those materials could have damaged the coating in multiple locations during the pipe installation or backfilling process, resulting in vulnerability of the small areas of exposed steel to corrosion. Since a relatively large surface area of the sample has no evidence of corrosion, exposure to leaking water or to water-saturated soil apparently did not have a significant effect on the protectiveness of the coating on the pipe. Rather, the large number of observed pits is more likely related to the occurrence of coating damage that occurred during installation; not to gradual or long term coating degradation that could potentially as a result of exposure to leaking water or water-saturated soil.

While the morphology of the external pitting included features that are typical of corrosion associated with MIC, the features are not unique to MIC. Likewise, the corrosion products in the external corrosion pits consisted primarily of siderite (iron carbonate), which can result from either MIC or from corrosion unrelated to microbiological activity (i.e., from abiotic corrosion). The siderite corrosion product can be formed either by MIC, or can be generated as a result of electrochemical corrosion of steel exposed to well buffered water containing little or no oxygen, a neutral to moderately high pH, and low calcium. The reported pH of the ground water matches this requirement. The available water analysis and soil analysis does not contain the information required to determine if the other attributes are within the range for siderite to be formed abiotically.

We determined that the corrosion rate responsible for causing the leak must have been at least 8 mpy (0.008 inches per year or 8 mils per year) to cause penetration of the pipe wall in about 40 years. Many soils could cause a long term corrosion rate of about 8 mpy or higher in the absence of MIC, so the high corrosion rates often associated with MIC are not necessary to cause the leakage. It is likely that the corrosion progressed discontinuously as water table levels rose and fell, or as the soil environment underwent other seasonal or temporary changes. As a result, the peak corrosion rate could have been significantly higher than 8 mpy and within the range associated with MIC. However, it is apparent that if MIC did contribute to the metal loss, it was not active the entire time the pipe was in service because the leak would have occurred much sooner.

Determining the probable rate of future metal loss at other locations of coating damage on this piping would require either directly measuring the rate with corrosion probes or buried coupons, or modeling the likely abiotic corrosion rates using soil analysis data. Insufficient soil data

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currently exists to estimate the corrosion rate that could be caused by the backfill in the absence of MIC.

Some preferential corrosion of the girth weld heat affected zone was apparent on both the ID and OD of the pipe, but the maximum depth of metal loss in the HAZ was no greater than the maximum depth of metal loss remote from the weld.

Corrosion on the inside surface of the sample was superficial and does not represent a significant threat to the integrity of the pipe. ID corrosion on the straight pipe was more widespread than in the elbow, resulting in an appearance more typical of general corrosion, rather than of pitting. ID pitting on the elbow consisted of individual small pits. The composition of the corrosion products from the inside of the sample was characteristic of corrosion by low oxygen content water and was significantly different from corrosion products on the OD of the pipe.

The metallurgical characteristics of the pipe, elbow, and girth welds were normal. The workmanship of the weld was good. No abnormalities in the steel or weld were present that could have contributed significantly to the corrosion, although the pipe composition deviated from the ASTM A106 specification with regard to silicon content. The composition did meet the requirements for comparable seamless pipe specifications.

Conclusions

1. Internal corrosion is present, but it is superficial and does not represent a threat to the operation of the piping. Minor differences in the extent of corrosion observed on the pipe and on the elbow are attributed to minor differences in the steel composition. The weld HAZ of the elbow appeared be to somewhat less resistant to corrosion than the areas of ethe elbow away from the weld, but no less resistant than the pipe.
2. We found no evidence of abnormalities in the metallurgical characteristics of the pipe, elbow, or the girth weld that would have contributed to the observed corrosion. The workmanship of the girth weld was very good. A minor variance in the chemical composition of the pipe from the applicable specification is inconsequential to its performance.
3. The coating quality could not be determined directly from the pipe samples submitted for analysis since the coating had been previously removed during the pipe repair process. However, the observed patterns of corrosion indicate that the coating continues to be protective where it is intact, but the existing coating quality may be somewhat lower on surfaces that are more difficult to wrap, such as fittings, as evidenced by larger areas of general corrosion on the surface of the elbow. The primary cause of localized pitting corrosion in areas surrounded by coating that appears to be generally intact is probably localized mechanical damage to the coating. The mechanical damage causes localized penetrations of the coating resulting in exposure of small areas of the steel surface to the soil environment. The coating damage most likely occurred during installation as a result of using backfill that contained angular rocks and debris. The calculated minimum average long term corrosion rate (about 8 mpy) that would have produced the recent leak is within the range of corrosion rates observed for pipe that is not cathodically protected when exposed to some soils, but lower than expected for MIC if the MIC mechanism was continuously active. Some soil analysis data was provided to SI, but not all of the

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attributes required for input into our SoilPro model were included in the available data. As a result, we are unable to determine if the soil characteristics at this leak site would be expected to cause an 8 mpy corrosion rate in the absence of MIC. The potential influence of MIC should not be disregarded since both the morphology of the metal loss and the type of external corrosion product present can be related to MIC, (although neither one is a definitive indicator of MIC). Two scenarios could describe the cause of the relatively low average corrosion rate in the presence of a MIC mechanism. First, it is possible that corrosion rates fluctuated during the time of service as water table depths rose and fell, resulting in periodic variations in soil properties. Those variations in soil properties could alternatively support or fail to support a MIC mechanism. In a second scenario, the initial corrosion rate could have been low and unrelated to MIC. After some time in service some environmental change occurred, such as a long term change in the water table, or a leak in adjacent piping. That transition could have triggered the onset of long term MIC (or of higher abiotic corrosion rates). Either case describes how the significantly higher corrosion rates often associated with MIC could have occurred only during a portion of the total service time.

Recommendations

1. Generalizations regarding what constitutes "corrosive soil" can be misleading, particularly when based on assessment of one or only a few soil parameters. Consider installing corrosion probes or corrosion coupons in the backfill with the means to monitor or retrieve the assemblies. Coupons or probes can help quantify corrosion rates, detect transients in corrosion rates, and assist in the determination of the mechanism of corrosion. Alternatively, if available, an additional soil sample could be analyzed to determine the attributes needed to run the SI SoilPro program and estimate the likely pitting rate that would be expected at the location of the sample. However, the SoilPro data will represent the snapshot in time at which the sample was obtained and will not address seasonal changes or transient conditions in the environment unless additional samples are taken at a later time

2. Consider focusing any future piping inspection on areas containing:
    a. Elbows and other harder to wrap fittings since those are preferential locations for coating anomalies.
    b. Backfill suspected of having the same characteristics at those observed at this leak since angular rocks may have caused coating damage at which corrosion can occur
    c. Areas where results of soil analyses indicate that corrosion rates may be the highest. In the absence of data that is sufficient to run the SI SoilPro corrosion rate model , select areas of lowest elevation and low resistivity since low resistivity is often associated with more corrosive soil. Note however that high resistivity soil may still be corrosive.

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d.

Appendix A – Observations by Entergy Engineering Staff Regarding the Excavation Conditions

Observation 1

- The initiating event was a report by Operations that the water level was rising in the sleeve of the 8" Condensate Return line in the Aux Feed Pump Room where the pipe goes into the floor
- On his own initiative, an Operator looked in the manhole just outside the Aux Feed Pump Room in the Main Feed Reg Valve Room and noticed water flowing in the manhole.
- The Condensate Storage Tank was declared inoperable
- Once the core boring was complete there appeared to be undermining of the area under the concrete slab.
- A lot of water was still coming into the hole during excavation
- During excavation and shoring, there were a lot of large rocks, cans, and other garbage in the fill that was used. The rocks were large enough to get stuck in the hose that was sucking out the mud from the hole
- Upon inspection of the pipe (the pipe was still leaking) there appeared to be a hole at the 7:00 position approximately 22" from the elbow weld joint.
- The coating was not present in the areas of the hole and/or indications. It appears to have been blown away over time. This could have been caused by initial damage to the coating during the backfill
- The area of the holes/indications probably saw constant groundwater and could have caused the erosion in the areas of the damaged coating. Note that the inside of the pipe was in pristine condition; no internal corrosion noted.

Observation 2

- Observed the area being excavated with sump pump installed, but no shoring yet. The hole was still ~ ½ full of water.
- Inspected pipe after clamp was installed. No areas coating had been stripped for UTs yet however, the coating appeared to be in bad shape and chewed up. Not sure if this was a result of the excavation, from original construction, or degradation over time.
- Additional observations of the coating indicated that it was not in uniform contact with the pipe and not tightly adhered to. Some scaling had occurred at some point as well.
- Did not witness the excavation activities however, did notice a lot of debris, especially stones in the area under the pipe. These were fist size or greater and seemed to be crushed rock not normally seen in areas of backfill.
- An indication was noted to have the appearance of a rock (or other object) that had been forced into the pipe and caused damage to the coating.
- Some of the pitting was very shiny which is unusual. It also appeared to be uniform in depth.

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Observation 3

- Did not observe excavation efforts, but did see ~ 6" – 7" in the area around the pipe once it was exposed.
- The coating was already stripped and prepped for UTs.
- Based on a review of the photos it appears that the coating may not have been applied consistently during original construction. The workmanship was not up to current standards. The coating has a "rippled" look to it.
- Pipe thickness looked good

Observation 4

- Once the core boring was complete, observed a lot of debris in the hole during excavation.
- Items included large rocks, metal pieces, and Styrofoam packaging material.
- The rocks were large enough to clog the hose that was used to suck out the mud during excavation
- The hose was getting clogged frequently due to the large rocks and debris to the point where the hose needed to be disconnected at the truck end in order to clear it out.
- The sump pumps also appeared to be clogging frequently.
- The pressure from the rocks could have been enough to damage the coating and the surface of the pipe.

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