Murray Selman
Vice President

Consolidated Edison Company of New York, Inc.
Indian Point Station
Broadway & Bleakley Avenue
Buchanan, NY 10511
Telephone (914) 737-8116

September 11, 1987

Re: Indian Point Unit No. 2
Docket No. 50-247

Mr. William Russell
Regional Administrator - Region I
U.S. Nuclear Regulatory Commission
631 Park Avenue
King of Prussia, PA 19406

Dear Mr. Russell:

Transmitted as Attachment A to this letter is our response to NRC Bulletin No. 87-01, "Thinning of Pipe Walls in Nuclear Power Plants", dated July 9, 1987. The response to this bulletin was requested within 60 days from the receipt of the bulletin, July 14, 1987.

Our response is provided pursuant to the provisions of Section 182a, Atomic Energy Act of 1954, as amended. Should you or your staff have any questions, please contact us.

Very truly yours,

Murray Selman

23.190.7.28.6

cc: Document Control Desk
U.S. Nuclear Regulatory Commission
Washington, DC 20555

Ms. Marylee M. Slosson, Project Manager
Project Directorate I-1
Division of Reactor Projects - I/II
U.S. Nuclear Regulatory Commission
Washington, DC 20555

Senior Resident Inspector
U.S. Nuclear Regulatory Commission
P.O. Box 38
Buchanan, NY 10511

Subscribed and sworn to
before me this 11th day
of September 1987

ANTHONY R. ARNONE
Notary Public, State of New York
No. 4883047
Qualified in Westchester County
Commission Expires January 26, 19 89

Anthony R. Arnone
Notary Public

IE11
1/1

Attachment A

Response to NRC Bulletin No. 87-01
"Thinning of Pipe Walls in Nuclear Power Plants"

Consolidated Edison Company of New York, Inc.
Indian Point Unit No. 2
Docket No. 50-247
September 11, 1987

Item 1. Identify the codes or standards to which the piping was designed and fabricated.

Response:

All Balance-of-Plant and NSSS piping design and fabrication is in accordance with United States American Standards (USAS) B31.1, 1967 edition, with the exception of the piping supplied as part of the turbine generator package (e.g. crossunder piping, crossover piping, turbine lube oil piping) which is designed and was fabricated to Westinghouse proprietary standards.

Item 2. Describe the scope and extent of your programs for ensuring that pipe wall thicknesses are not reduced below the minimum allowable thickness. Include in the description the criteria that you have established for:

a. selecting points at which to make thickness measurements
b. determining how frequently to make thickness measurements
c. selecting the methods used to make thickness measurements
d. making replacement/repair decisions

Response:

In 1984, Con Edison established an extraction steam inspection program based on recommendations contained in INPO SOER 82-11 "Erosion/Corrosion of Steam Piping and Resulting Failure." This program involves the inspection of elbows and tees in the extraction steam lines from the high pressure and low pressure turbines to feedwater heaters Nos. 23 through 26. The locations selected for inspection were chosen based on moisture content, operating pressure and piping configuration. Since the program's inception, we have had two refueling outages, during which we inspected approximately a total of 32 percent of the locations originally chosen for examination. Numerous inspections were made at each location using the UT method. Determination of the minimum pipe wall thickness was based on the applicable piping design code for the plant, USAS B31.1. A portion of the remaining 68% of the locations will be inspected with the expanded inspection program described in response to Item 5, and a portion of the 32% previously inspected will be reinspected.

In addition, the turbine generator crossunder piping is being inspected during refueling outages. The inspection consists of 100% visual examination. Visual examinations are utilized to highlight areas for ultrasonic measurement.

As a result of the Surry event, we have augmented our inspection program to include the following single phase systems: the main feedwater system, the condensate system, the heater drain pump discharge piping and the auxiliary feedwater system. This program utilizes the UT method and visual examinations. EPRI report NP-3944 entitled "Erosion/Corrosion in Nuclear Plant Steam Piping: Causes and Inspection Guidelines", EPRI report entitled "Single Phase Erosion/Corrosion of Carbon Steel Piping" and other relevant industry reports were utilized in enhancing our augmented inspection program. Additional information in development of the program was obtained from the Surry Power Station Unit 2 report entitled "Reactor Trip/Feedwater Pipe Failure," dated December 9, 1986.

Approximately one hundred and eleven locations were chosen in the condensate, feedwater, heater drain, and auxiliary feedwater systems for inspection. Location selection criteria utilized were fluid velocity, piping material, fluid temperature, fluid pH, oxygen content and piping configuration. Here too, numerous inspections were made at each of these locations using the UT method. These inspections were made during the period from December 1986 through February 1987. There was no significant erosion/corrosion found in these systems. Our plan at the present time calls for the selection of additional locations in the main feedwater, condensate and heater drain systems, as described in the response to Item 5. The inspection frequency for those locations is presently under evaluation.

The ultrasonic testing method was chosen for pipe thickness measurements. This technique is the most accurate and practical method for measuring pipe wall thickness. Measurements are taken on grid patterns determined upon the size of the component to be measured. A step block is used periodically to verify instrument calibration.

USAS B31.1 provides methodology to calculate the allowable minimum piping thickness based on design conditions, i.e. pressure and temperature and allowable stresses which vary depending on the material selected for the application. The minimum code allowable thickness is then compared with the actual UT measured thickness. Repair/replacement decisions are based on actual thickness readings approaching the code minimum allowable and assessment of the wear rate. The wear rate determination is made based on the difference in thickness between the installed nominal and actual measured, divided by the operating years of service the component has been in use. If the wear rate indicates the component may approach the code minimum allowable thickness within an eighteen month operating cycle the component measurement frequency will be increased or a repair/replacement decision will be made.

Item 3. For liquid-phase systems, state specifically whether the following factors have been considered in establishing your criteria for selecting points at which to monitor piping thickness (Item 2a):

a. piping material (e.g., chromium content)
b. piping configuration (e.g., fittings less than 10 pipe diameters apart)
c. pH of water in the system (e.g., pH less than 10)
d. system temperature (e.g., between 190 and 500° F)
e. fluid bulk velocity (e.g., greater than 10 ft/s)
f. oxygen content in the system (e.g., oxygen content less than 50 ppb)

<u>Response</u>:

In liquid-phase systems, i.e. 100 percent water in liquid form, Con Edison utilized the criteria in EPRI report "Single Phase Erosion/Corrosion of Carbon Steel Piping." An outside vendor was used to evaluate the single phase system locations which would be most susceptible to erosion/corrosion.

The following factors were considered:

a. Piping material - Alloy steels with more than 1 percent chromium generally have ten times the erosion/corrosion resistance as carbon steel. As a result, inspection of alloy steels is not planned in single phase service systems and we are therefore only evaluating carbon steel components. Data generated by Electricite de France (EDF) and Sulzer show that erosion/corrosion is possible in 1CR-1/2Mo alloy steel. However, we are not aware of any failures of chromium-molybdenum steel in single phase service in a PWR piping system.

b. Piping configuration - The piping evaluation considered the following:

   - Short radius elbows
   - Pipe sections where fittings and valves are within 10 pipe diameters
   - Fittings downstream and close to orifices
   - Areas downstream of control valves
   - Two changes or more of flow direction occurring within 10 pipe diameters

c. pH effects - Fluid pH was utilized in analytical wear rate calculations similar to that which is stated in the EPRI report "Single Phase Erosion/Corrosion in Carbon Steel Piping."

d. Fluid Velocity - Velocities were calculated throughout single phase systems identified for the study. Areas where the velocity may be greater than current industry standards are considered for NDE inspection.

e. Temperature effects - Temperature considerations are based on the work published by the Central Electricity Generating Board (CEGB) research laboratories in England. The CEGB found carbon steel in single phase systems was most sensitive to erosion/corrosion in the range of 265°F to 280°F. Systems in the inspection program have temperature ranges from approximately 150°F to approximately 450°F, with the exception of the main steam system.

f. Oxygen content - The boiler feedwater and condensate systems have oxygen levels less than the 5 parts per billion range. These levels are maintained to enhance steam generator integrity.

Item 4. Chronologically list and summarize the results of all inspections that have been performed, which were specifically conducted for the purpose of identifying pipe wall thinning, whether or not pipe wall thinning was discovered, and any other inspections where pipe wall thinning was discovered even though that was not the purpose of that inspection.

a. Briefly describe the inspection program and indicate whether it was specifically intended to measure wall thickness or whether wall thickness measurements were an incidental determination.

b. Describe what piping was examined and how (e.g., describe the inspection instrument(s), test method, reference thickness, locations examined, means for locating measurement point(s) in subsequent inspections).

c. Report thickness measurement results and note those that were identified as unacceptable and why.

d. Describe actions already taken or planned for piping that has been found to have a nonconforming wall thickness. If you have performed a failure analysis, include the results of that analysis. Indicate whether the actions involve repair or replacement, including any change of materials.

Response:

The following is a list (Table 1) of all the inspections that have taken place since the December 9, 1986 Surry event which were specifically intended to measure wall thickness. The program was intended to examine elbows and tees in the single phase systems which are identified using the criteria stated in response to Item 3. The inspections included those systems listed in response to Item 2. In addition, an area in the drain lines from the No. 26 feedwater heaters to the heater drain tank was measured for wall thickness.

The inspections utilized the ultrasonic test method. Calibration of the ultrasonic instrumentation was performed using a step block in 0.100", 0.200", 0.300", 0.400", and 0.500" increments. The inspections were performed in approximately 2 inch grid patterns. As a means of locating measurement points in subsequent inspections, the intent will be to scan entire areas that show signs of wall thinning and thereby encompassing the original measurement point. The result of the inspections are summarized in Table 1.

The drain line from the 26C feedwater heater to the heater drain tank failed in April 1987. Subsequent failure analysis indicated that the material installed was not the material specified in the mechanical material listing contained in the modification procedure. The material installed during a modification in 1984 was determined to be similar to A106 grade B. The material specified was A335 grade P5. The results of the failure analysis are attached (Attachment B). The spool pieces in the 26A and B drainlines (See Table 1, Locations 21 and 22) were UT measured and determined to be acceptable until they can be replaced during the upcoming refueling outage. The 26C spool piece (See Table 1, Location 20) was changed out and a stainless steel spool piece was installed.

TABLE 1

Single Phase System Pipe Inspection
Pipe Wall Thickness

Location	System	Component Type	Nominal Pipe Diameter (inches)	Nominal Wall Thickness (inches)	Code Minimum Calculated (inches)	UT Measured Highest (inches)	UT Measured Lowest (inches)	
1	HD	ELBOW	16	.50	.382	.775	.632	
2	HD	ELBOW	16	.84	.382	.824	.752	
3	CD	STR. PIPE	24	.688	.532	.650	.638	
4	CD	ORIFICE	24	.688	.532	.745	.650	
5	CD	ELBOW	24	.688	.532	.825	.674	
6	CD	ELBOW	24	.688	.532	.850	.662	
7	HD	ELBOW	12	.50	.305	.632	.519	
8	HD	ELBOW	12	.50	.305	.656	.530	
9	CD	ELBOW	24	.688	.532	.800	.673	
10	CD	PIPE	24	.688	.532	.745	.680	
11	CD	ELBOW	24	.688	.532	.844	.744	
12	HD	PIPE	12	.50	.305	.537	.460	
13	HD	ORIFICE	12	.50	.305	.525	.479	
14	HD	STR. PIPE	12	.50	.305	.533	.506	
15	HD	ORIFICE	12	.50	.305	.524	.500	
16	BFD	STR. PIPE	20	1.031	.797	1.076	.990	
17	BFR	ELBOW	6	.864	.35	.969	.804	
18	BFD	ELBOW	20	1.031	.797	1.516	1.118	
19	BFD	ELBOW	20	1.031	.797	1.287	1.121	
20	6EX	SPOOL	6	.280	.125	.280	.075	(See Note)
21	6EX	SPOOL	6	.280	.125	.255	.210	
22	6EX	SPOOL	6	.280	.125	.260	.210	

Note: The 26C feedwater heater spool piece was changed out and a stainless steel spool piece was installed.

HD Heater drain pump discharge to MBFP suction
CD Condensate pump discharge to MBFP suction
BFD MBFP discharge
BFR MBFP recirculation to condenser
6EX 26 feedwater heater drain to heater drain tank

Every elbow and tee in the auxiliary feedwater system, which consists of ninety-three locations, was measured. All wall thickness measurements were above minimum code allowable wall thickness.

The following is a summary of available inspection results for the 1986 crossunder piping (Table 2) and the extraction steam piping (Table 3) inspections. The data upon which the inspection results are based is voluminous and is therefore only summarized in this report. However, the data is available onsite for review.

1. The turbine generator crossunder piping was pieced out in 1982. Available records indicate 19 sections were replaced with the same material. Crossunder inspections are performed during refueling outages. The inspection consists of 100% visual examination. Visual examinations are utilized to highlight areas for ultrasonic measurement or pit gauge measurement. The inspection results from the 1986 Refueling Outage are summarized in Table 2.

   In 1986, pre-separators were installed in the crossunder piping. It is felt the pre-separators will reduce the erosion/corrosion in these piping systems.

2. Thirty-eight extraction steam piping components were ultrasonically inspected. The components were examined in a grid pattern. Seven components required weld repair because they were below established engineering acceptance criteria. The results are listed in Table 3.

TABLE 2
Crossunder Pipe Inspections

Location	System	Component Type	Nominal Pipe Diameter (inches)	Pipe Wall Thickness: Nominal Wall Thickness (inches)	Pipe Wall Thickness: Code Minimum Calculated (inches)	Pipe Wall Thickness: UT Measured Highest (inches)	Pipe Wall Thickness: UT Measured Lowest (inches)
53-1A	CU	PIPE	46.2	1.00	.388	.830	.780
53-1A*	CU	REDUCER	46.5 X 37	.5	.304	.360	.100
53A-2A	CU	PIPE	37	.5	.304	.504	.420
53A-3A	CU	PIPE	37	.5	.304	.490	.380
53A-4A*	CU	PIPE	37	.5	.304	.350	.260
53A-5A	CU	PIPE	26.5	.5	.220	.370	.250
53B-5A*	CU	PIPE	37	.5	.304	.370	.283
53B-6A	CU	PIPE	26.5	.5	.220	.602	.415
53B, 60-7A*	CU	PIPE	26.5	.5	.220	.250	.100
60-8A	CU	PIPE	26.5	.5	.220	.390	.280
58-9A*	CU	PIPE	26.5	.5	.220	.360	.325
58-9A*	CU	PIPE	26.5	.5	.220	.312	.179
56-10A	CU	PIPE	26.5	.5	.220	.400	.291
52-11A*	CU	PIPE	32	.5	.264	.682	.223
51-12A*	CU	PIPE	32	.5	.264	.478	.116
41-1A	CU	PIPE	46.5	1.0	.388	1.0	.928
41-1A	CU	PIPE	37	.5	.304	.629	.281
41A-2A	CU	PIPE	37	.5	.304	.470	.428
41A-3A	CU	PIPE	37	.5	.304	.518	.450
41A-4A	CU	PIPE	37	.5	.304	.244	.340
41A-5A*	CU	PIPE	37	.5	.304	.855	.294
41B-6A	CU	PIPE	26.5	.5	.220	.620	.271
41B-7A	CU	PIPE	26.5	.5	.220	.480	.426
41B-8A	CU	PIPE	26.5	.5	.220	.628	.460
47-9A	CU	PIPE	26.5	.5	.220	.454	.318
44-10A	CU	PIPE	26.5	.5	.220	.449	.258
44-11A	CU	PIPE	26.5	.5	.220	.415	.266
39, 40-12B	CU	PIPE	32	.5	.264	.410	.372
39, 40-12B	CU	PIPE	32	.5	.264	.709	.320

* Repairs were made using the clad overlay technique.

CU Turbine generator crossunder piping

TABLE 3
Extraction Steam Inspections

Location	System	Component Type	Nominal Pipe Diameter (inches)	Pipe Wall Thickness: Nominal Wall Thickness (inches)	Code Minimum Calculated (inches)	UT Measured Highest (inches)	UT Measured Lowest (inches)
1	3EX	ELBOW	20	.25	.125	.531	.334
2	3EX	ELBOW	20	.25	.125	.561	.385
3	3EX	TEE	28	.3125	.125	.349	.294
4	3EX	ELBOW	28	.3125	.125	.436	.316
5	3EX	ELBOW	20	.25	.125	.593	.403
6	3EX	ELBOW	20	.25	.125	.541	.393
7	3EX	TEE	28	.3125	.125	.354	.296
8	3EX	ELBOW	20	.25	.125	.54	.345
9	3EX	ELBOW	28	.3125	.125	.470	.325
10	3EX	ELBOW	20	.25	.125	.522	.366
11	3EX	ELBOW	20	.25	.125	.596	.302
12	3EX	ELBOW	20	.25	.125	.591	.324
13	4EX	ELBOW	20	.25	.125	.518	.426
14	4EX	ELBOW	20	.25	.125	.557	.337
15	3EX	STR. PIPE	14	.210	.125	.280	.220
16	3EX	STR. PIPE	18	.25	.125	.255	.220
17	3EX	ELBOW	28	.3125	.125	.447	.362
18	4EX	ELBOW	20	.25	.125	.519	.412
19	4EX	ELBOW	20	.25	.125	.520	.444
20	4EX	ELBOW	20	.25	.125	.505	.370
21	4EX	ELBOW	20	.25	.125	.526	.424
22	4EX	ELBOW	20	.25	.125	.505	.403
23	4EX	ELBOW	20	.25	.125	.526	.424
24	4EX	ELBOW	20	.25	.125	.490	.423
25*	5EX	ELBOW	28	.375	.30	.444	.271
26*	5EX	TEE	28X18	.375/.312	.30/.18	.413/.307	.364/.167
27*	5EX	TEE	28X18	.375/.312	.30/.18	.410/.300	.360/.077
28*	5EX	ELBOW	28	.375	.30	.444	.280
29*	5EX	ELBOW	28	.375	.30	.440	.213
30	5EX	ELBOW	28	.375	.30	.438	.311
31	5EX	ELBOW	18	.312	.18	.466	.302
32	5EX	ELBOW	28	.375	.30	.430	.324
33	6EX	ELBOW	18	.438	.261	.537	.419
34*	6EX	TEE	12X18	.250/.438	.18/.267	.360/.496	.182/.382
35*	6EX	TEE	12X18	.250/.438	.18/.267	.347/.496	.165/.496
36	3EX	STR. PIPE	28	.3125	.125	.396	.373
37	3EX	ELBOW	28	.3125	.125	.422	.358
38	3EX	ELBOW	28	.3125	.125	.436	.370

* Repairs were made by welding a fitted pipe plate over the affected area.

3EX,4EX,5EX,6EX Extraction steam from Turbine to 23,24,25,26 feedwater heater.

Item 5. Describe any plans either for revising the present or for developing new programs for monitoring pipe wall thickness.

<u>Response</u>

We are expanding our high energy pipe inspection program. In addition to the extraction steam program, the following systems are being added to that program:

- Condensate
- Feedwater
- Moisture Separator Drains
- Feedwater Heater Drains
- Steam Generator Blowdown

Our objective is to develop a 10-year inspection program. Due to the extensive addition of inspection locations, we have elected to rely on the analytical study of these systems to determine the priority for the inspection points to be monitored. The analytical study using methodologies set forth in EPRI report NP-3944, "Erosion/Corrosion in Nuclear Plant Steam Piping" and EPRI report "Single Phase Erosion/Corrosion of Carbon Steel Piping" has identified 98 areas for actual NDE measurement. In addition, the EPRI CHEC program will be used in supplementing the analytical study where possible.

Attachment B

Metallurgical Analysis Summary Report

Consolidated Edison Company of New York, Inc.
Indian Point Unit No. 2
Docket No. 50-247
September 11, 1987

5/27/87

CON EDISON

File No.: MET199
Date: 5/1/87

CHEMICAL SECTION
METALLURGICAL ANALYSIS SUMMARY

Location: Indian Point Station

Sample Description: 6 inch spool piece between the level control valve (LCV-1103) and the isolation valve from Feedwater Heater No. 26C to the Heater Drain Tank.

Test(s) Requested: Cause of failure.

Results: The location of the failure is shown in the attached drawing. The spool piece normally operates at 390 degrees F. and 180 psig. The feedwater condensate is typically between 8.9 and 9.2 and was within limits at the time of the failure. The oxygen concentration in the condensate was 4.8 ppb. The piping from the heater to LCV-1103 is 10 inch schedule 40; after the LCV, the spool piece is 6 inch schedule 40. As a result of the decrease in diameter, a significant increase in feedwater flow rate occurs. The pipe was in service approximately 4 to 5 years.

The as-received spool piece is shown in Figure 1. The failure consisted of a circular thin-lipped rupture approximately midway between the the pipe-to-flange welds. The spool piece was 12 inches long. In the Laboratory, a transverse section was cut through the pipe approximately 1 inch from the failure. The extensive wall thinning which occurred on the failed side of the pipe is shown in Figure 2. Ultrasonic thickness measurements over the surface of the pipe is provided in Figure 3. The measurements ranged from 0.075 inch near the failure to a maximum of 0.200 inch. The specified wall thickness was 0.280 inch (schedule 40).

Metallurgical examination of the spool piece revealed that the microstructure was normal pearlite and ferrite for carbon steel, see Figure 4. Chemical analysis revealed that the spool piece was manufactured from plain carbon steel with a carbon content of 0.14% and a chromium, molybdenum and copper content of 0.01% each. This material conforms to the ASTM Specifications A106 Grade A and A333

Grade 1. The flange was a plain carbon steel with a carbon content of 0.23%.

The United Engineers & Constructors (UE&C) Specification 9321-01-248-18 Class D2 for 10 inch and smaller schedule 40 pipe from the level control valve to the heater drain tank for Heater No. 6 requires ASTM A335 Grade P5 alloy steel for piping and ASTM A182 Grade F5 alloy steel for flanges, see the attached page 18A of the piping specification. Grades P5 and F5 alloy steel consists of 0.15% carbon max., 4.0 - 6.0% chromium and 0.45 - 0.65% molybdenum.

A scanning electron micrograph was obtained and is provided in Figure 5. This structure was typical of the internal surface of the pipe. This topographic scalloped surface was also reported in the elbow failure at Navajo Generating Station Unit 3 in November 1982.

Cause of Failure: Based upon the evidence presented above, the cause of failure was single phase erosion-corrosion, also referred to as flow-assisted-corrosion. The failure can be attributed to the installation of an incorrect material for the specified operating conditions.

Single phase erosion-corrosion results when a combination of conditions are met:

- Flow disturbance configurations
- High water velocity (>15 fps)
- High water purity
- Carbon steel with low trace amounts of chromium
- Temperatures greater than 200 degrees F.
- Low oxygen content of water (<50 ppb).
- pH less than 9.3 accelerates the problem.

The current failure is similar to the single phase erosion-corrosion failures of the feedwater pipe at Surry Power Station Unit 2 in December 1986, and the feedwater pipe failure at the Navajo Generating Station Unit 3 in November 1982. The main difference is that this failure was in a straight section of pipe whereas the others were in curved sections of piping. All failures occurred where there were flow disturbance configurations.

The effect of the erosion-corrosion rate as a function of chromium content in steel is shown in the attachment from the EPRI Workshop on Erosion-Corrosion of Carbon Steel Piping - Nuclear and Fossil Plants, April 1987.

Recommendations: All feedwater piping should be inspected by ultrasonic thickness testing to determine the extent of the problem. An inspection program is currently being formulated at Indian Point by Quality Assurance.

All in-service and replacement spool pieces should be evaluated to determine conformance to UE&C piping specifications. Engineering should evaluate the piping configuration to determine the extent that the piping geometry contributed to the failure.

EPRI has developed a report for Nondestructive Examination of Ferritic Piping for Erosion/Corrosion, Research Project 1570-2. The report details an overall NDE inspection program.

When the two spool pieces associated with feedwater heaters 26A and 26B are replaced, they should be sent to the Metallurgical Laboratory for evaluation.

Reported to: Raymond Sutton

Date Reported: 4/30/87
Date Received: 4/8/87

Reported by: Paul H. Cohen

Prepared by: Paul H Cohen

cc: Murray Selman
John Basile
Malcolm Smith
John Curry
Michael Blatt
Joseph Mor
Horst Zitzelsberger
Victor Mullin
Raymond Sutton
Robert Altadonna
Joseph Higgins
Samuel Rothstein
Peteris Skulte
Alvin Moskowitz
Raymond R. Kimmel/Station Specialist: Richard Peters
Jimmy T. Mark
Paul H. Cohen
Metallurgical Laboratory File: MET 199

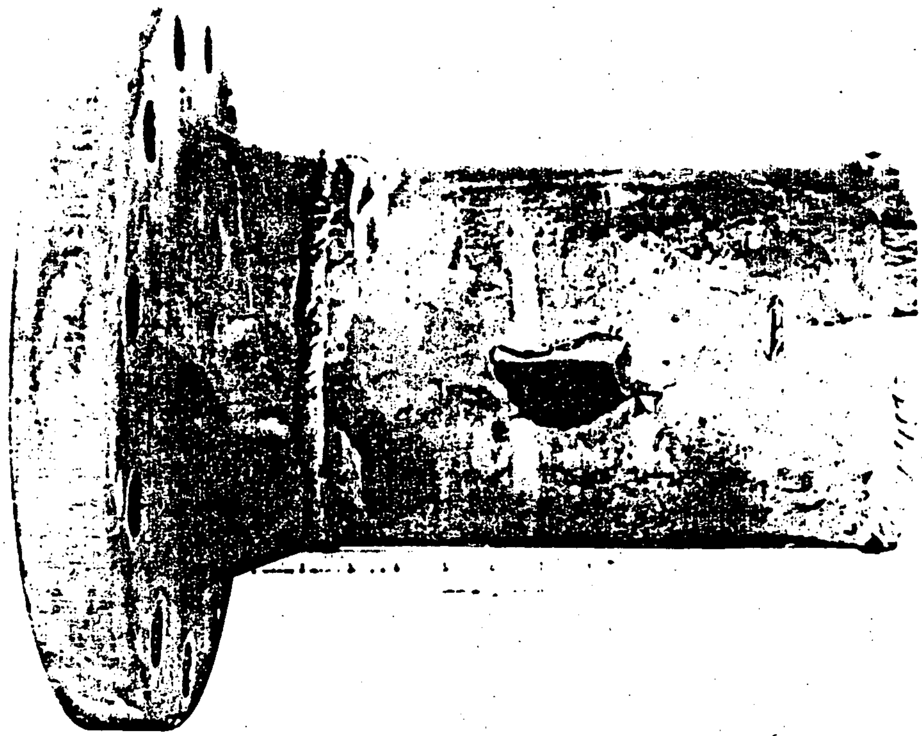


FIGURE 1

As-received 6 inch schedule 40 spool piece

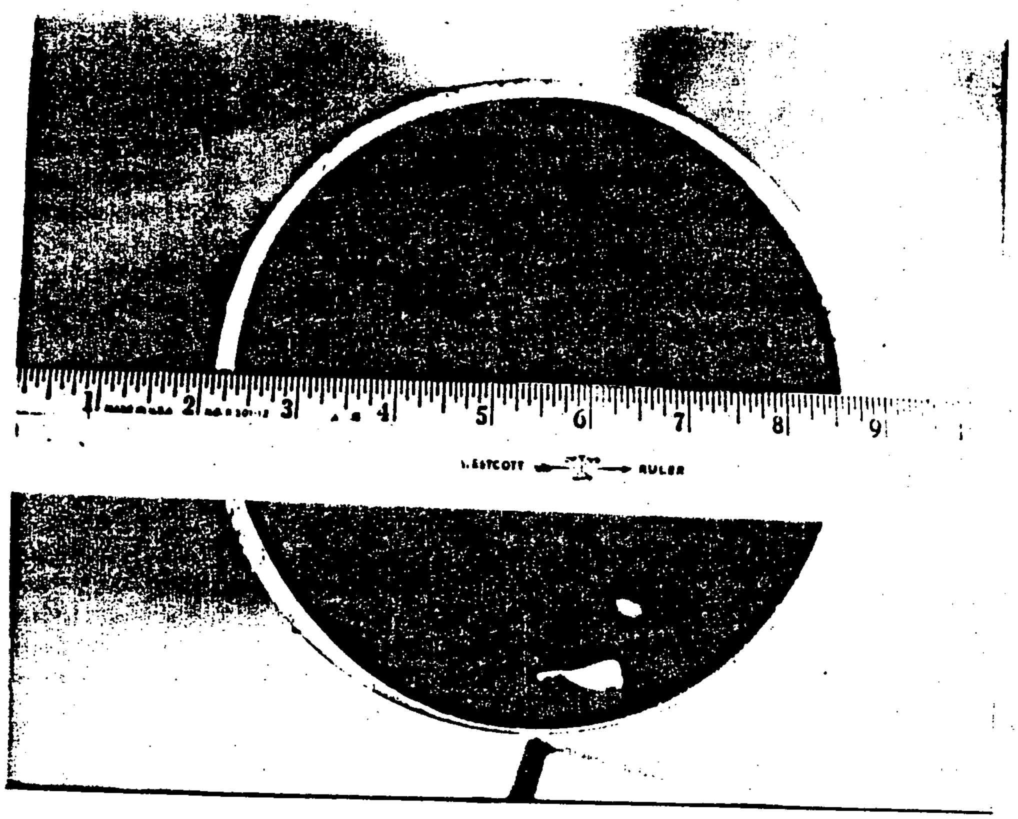


FIGURE 2

Extensive, nonuniform wall thinning is seen.
The failure is on the bottom.

Weld

Section

Section

7	8	9	10	11	12 o'clock	1	2	3	4	5	6
.130	.200	.185	.135	.095	.090	.080	.155	.185	.185	.155	.135
.125	.185	.185	.160	.100	.090	.090	.150	.190	.200	.140	.130
.130	.175	.200	.165	.095	.085 Damaged	.090	.155	.195	.175	.125	.135
.120	.160	.200	.170	.090	Failure	.075	.160	.190	.145	.115	.135
.135	.170	.205	.190	.110	Damaged .090	.080	.180	.190	.145	.115	.155

Flange

FIGURE 3

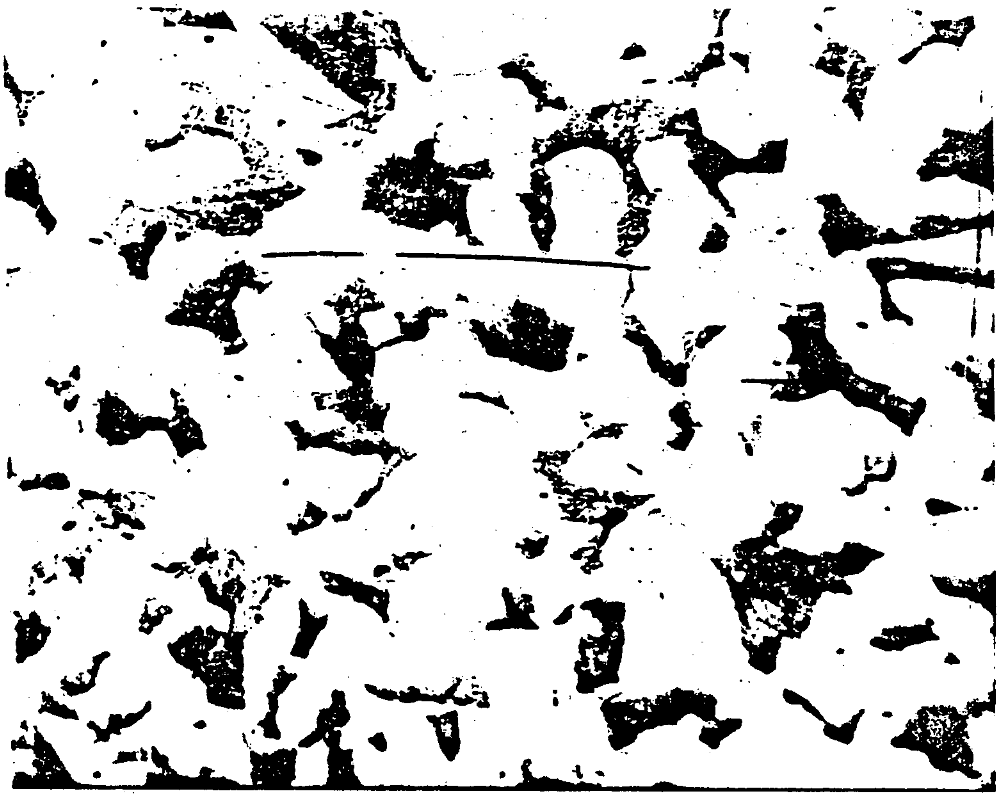


FIGURE 4

Microstructure of the carbon steel pipe shows typical pearlite (dark) and ferrite (white).
Magnification: 500x.

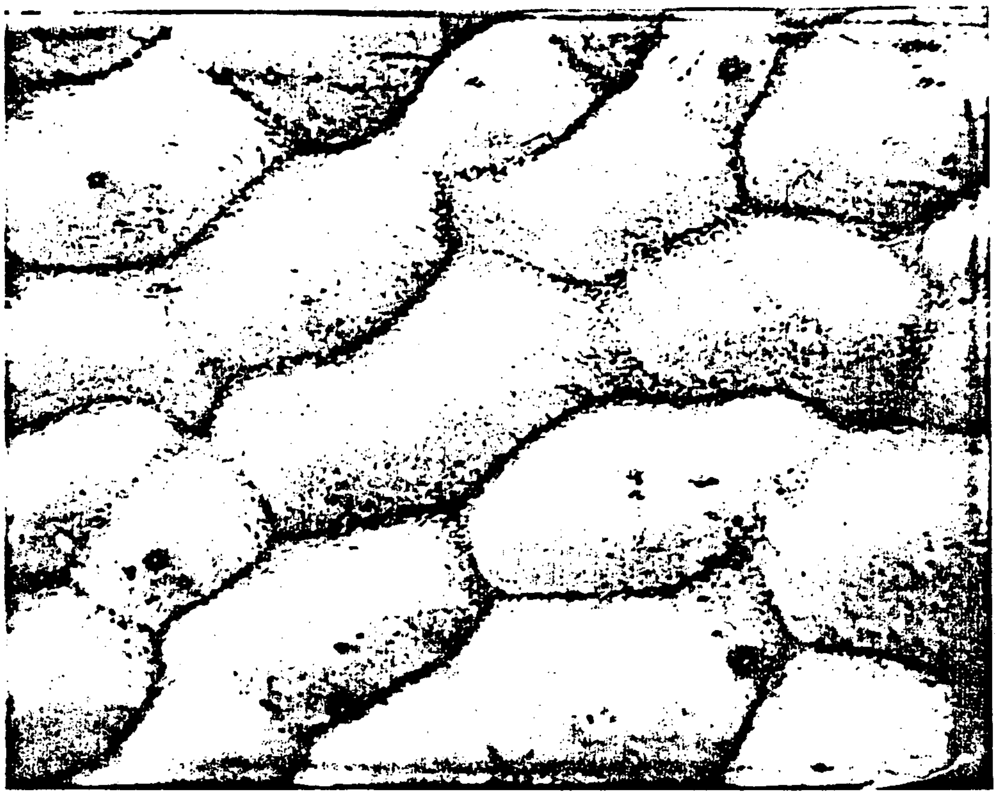
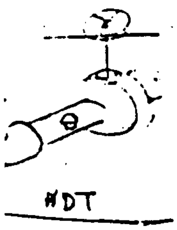
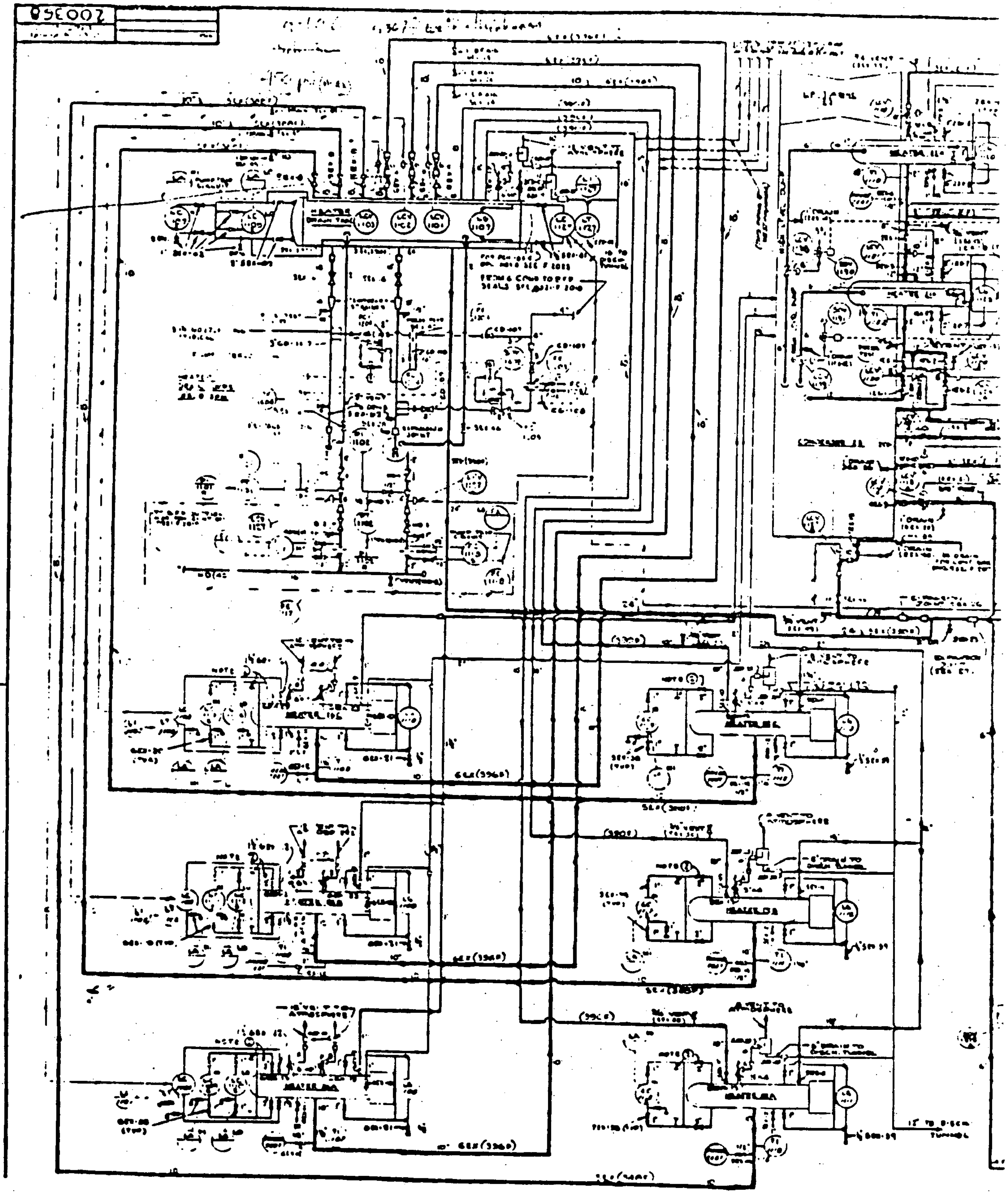


FIGURE 5

Scanning electron micrograph of the internal surface of the pipe. The scalloped surface is typical of erosion-corrosion failures. Magnification: 40x.


HDT


85E002

CLASS	D-2
PREFIX	6EX
PRESSURE	450 psig
TEMP. °F	450

UNITED ENGINEERS & CONSTRUCTORS INC. PAGE 18A
Westinghouse Electric Corporation
Indian Point Generating Station-Unit No. 2
Consolidated Edison Company of New York

Date: Dec. 1, 1967 Specification No.: 9321-01-248-18
Revision: Part A*

PIPE	MATERIAL	GRADE	SCHEDULE
10" & smaller	A-335	P5	40

VALVES	MATERIAL	SERIES*	END	STEM	DISC	SEAT
2½" & larger	A-217-WC6	300# ANSI	B.W.	S.S.	S.S.	S.S.

FITTINGS	MATERIAL	SERIES	ENDS	SCHEDULE
2½" & larger	A-234-WP5	--	B.W.	to suit pipe

FLANGES	MATERIAL	SERIES*	TYPE	FACING	BORE
2½" & larger	A-182-F5	300# ANSI	W.N.	R.F.	to suit pipe

	MATERIAL	HEAD	FINISH
BOLTS	A-193 Gr. B-7	Full threaded bolt studs	
NUTS	A-194 Gr. 2H*	Hex.	Semi-finished

GASKETS	MATERIAL	TYPE	THICKNESS
	304 S.S.	Flexitallic	

BACKING RINGS None.

UNIONS None.

SERVICE
1. No. 6 Heater drains from level control valve to Heater Drain Tank.

REMARKS
1. (*) Denotes Spec. updated as of 6-28-74

659

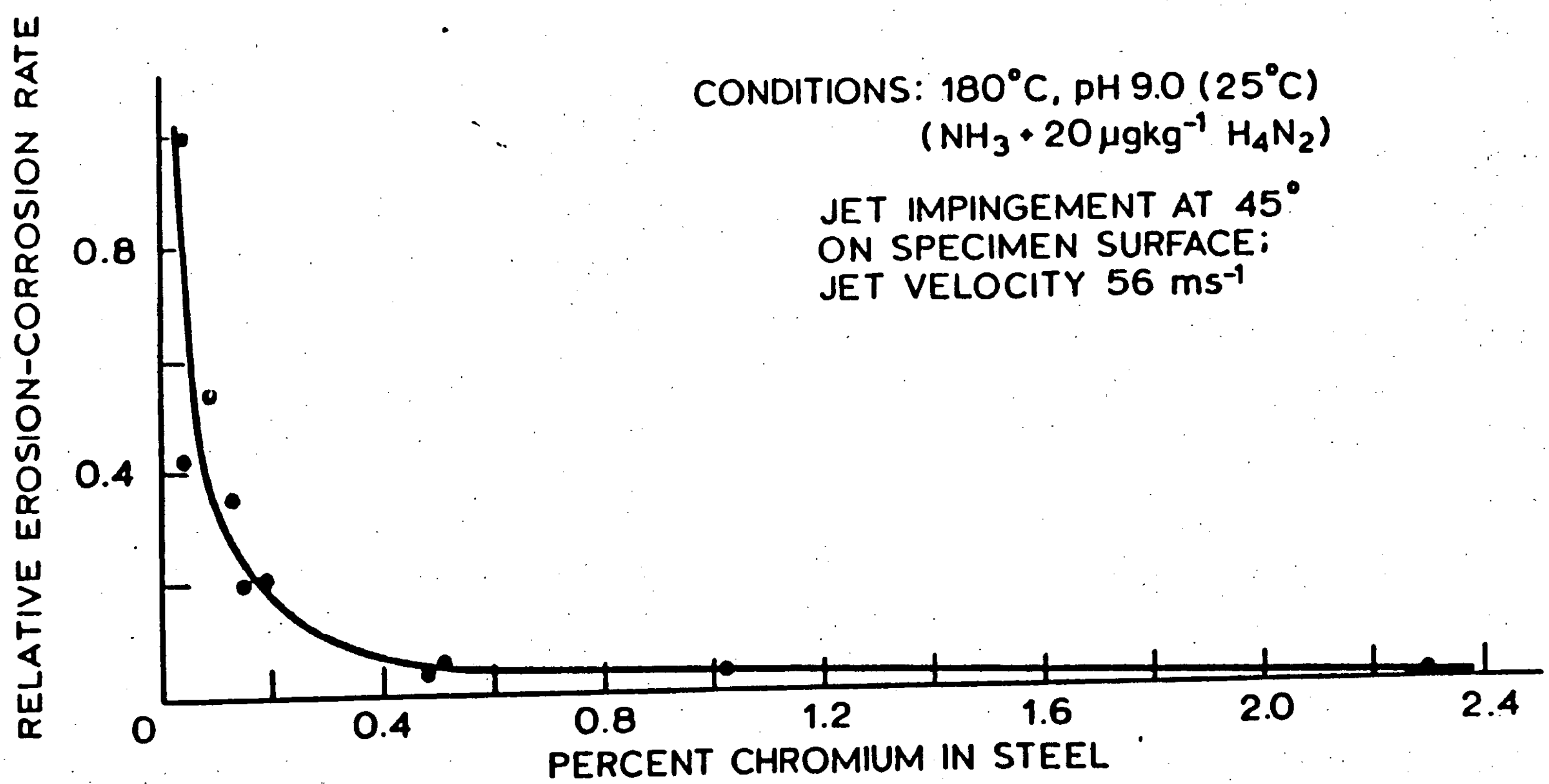


FIG. 4 EFFECT OF CHROMIUM CONTENT ON EROSION-CORROSION RATE OF MILD AND LOW CHROMIUM ALLOY STEELS (DUCREUX, 1982)