Spill 14538

Lakehead Pipe Line Company, Inc.

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Denise M. Hamsher Manager Safety, Environment & Compliance
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July 6, 1992

LSA20206

Mr. Ivan Huntoon
Department of Transportation
Office of Pipeline Safety
Room 1811
911 Walnut Street
Kansas, MO 64106

Dear Mr. Huntoon:

For your information, attached is a copy of a revision to our Operating and Maintenance Procedures Manual (Volume II) which formalizes a practice put into place soon after the March 1991 oil spill in Grand Rapids, Minnesota. We agreed with the Minnesota Pollution Control Agency to notify you of this revision to our written procedures.

Please contact me if you have any questions.

Sincerely,

Denise M. Hamsher

jib
Attachment

bcc: Paul Norgren
Jon Staudohar

3. UNEXPLAINABLE INCREASES OR DECREASES IN LINE PRESSURE OR FLOW RATE

a. Scope: If an operator experiences pressure or flow abnormalities or unexplainable changes in line conditions for which a reason cannot be established within a 10 minute period, the line shall be shutdown, isolated and evaluated until the situation is verified and/or corrected.

b. Potential Indicators: Within the 10 minute allowable time frame the operator shall review historical line data to check for conditions which may be representative of a leak situation.

Note: If a leak is suspected, neither pump configuration or rate should be changed until reasonably certain that a leak actually exists (or within 10 minutes, whichever is shorter). This will aid in the ability to properly evaluate line conditions without introducing other changes.

4. Notifications and Reporting:

When a pipeline is shutdown as a result of abnormal conditions that are unexplainable within the 10 minute period, the Control Center is responsible for making the following notifications in the order listed below:

1. District Management (if not already consulted)
2. Local Law Enforcement Agency
3. Minnesota Only - Minnesota State Duty Officer
4. Oil Movements (IPL)

Criteria for additional internal & external notification & reporting requirements are explained in detail in the Emergency Response Policy Manual, Section 3 - "Emergency Notification Procedures".

Cys to Stewart (6)
Rick
Ivan

Lakehead Pipe Line Company

Tom W. Fridel Manager, Operations Services

Lake Superior Place
21 West Superior Street
Duluth, MN 55802-2067
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DOT-RSPA-OPS

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CENTRAL REGION
KANSAS CITY, MO

CPF 36523

December 2, 1998

Rick Gulstad, P.E.
Engineer, Central Region
Department Of Transportation
Office of Pipeline Safety
1100 Main Street, Suite 1120
Kansas City, MO 64105

Dear Rick:

In response to your inquiry regarding Lakehead's Line 3 integrity program, I ask that you review the attached "Line 3 Integrity Assessment and Recommendations" report dated April 28, 1998. This report answers many of your questions, including the following key elements of Lakehead's Line 3 integrity program:

- 100% inspection of Line 3 for longitudinal seam cracks by the year 2001.
- 100% ultrasonic inspection for metal loss (completed in 1998, awaiting results).
- continued in-line crack inspection, approximately every 10 years.
- continued in-line inspection for metal loss, approximately every 5 years, pending results of the 1998 inspection.
- Betafoil development, monitoring and analysis.
- continued research into crack growth and corrosion; trending and analysis of inspection results.
- research and analysis of effective external corrosion control methods, including pipe coatings.
- ongoing pipeline operator training.
- monitoring, analysis and management of pressure cycle magnitude and frequency.
- risk management approach to pipeline integrity.

Lakehead's integrity management program goes significantly beyond the intent of the Consent Order directives in substantiating the proven integrity of Line 3. It is a multi-faceted proactive program that addresses all current and anticipated future integrity-related concerns.

Lakehead's actions subsequent to the Consent Order Agreement have significantly exceeded the requirements and directives of the Order. Our aggressive, proactive and risk-based integrity management program has addressed longitudinal seam cracks in USS SAW pipe, corrosion, operator training and pressure cycling. Lakehead has made a commitment to continue this focussed approach into the future. Several presentations have been made in which Lakehead has communicated the status and results of ongoing integrity programs. We have and will continue to maintain a philosophy of encouraging participation in periodic formal presentations to share information on our ongoing integrity management performance with the OPS at both the Federal and State levels.

Lakehead's commitment to personnel training will ensure that awareness of Line 3 issues including history and evolution of the integrity program are maintained. Lakehead presents the attached updated tables as supplemental information to the original ORA and, as such, recommends that the Consent Order be officially closed.

Sincerely,

[redacted]

Tom Fridel

smb
Attachment

c: Ivan Huntoon
Susan Miller
Rick Sandahl
Carl Mikkola

In-line inspection detects early cracking on Canadian crude-oil line

Susan E. Miller *Interprovincial Pipe Line Inc. Edmonton*
Michael A. Gardiner, Clive R. Ward *BG Technology Loughborough Leicestershire, U.K.*

A program of in-line inspection (ILI) in 1996 by Interprovincial Pipe Line Inc. (IPL), Edmonton, established the integrity of one particular line segment before it was hydrotested.

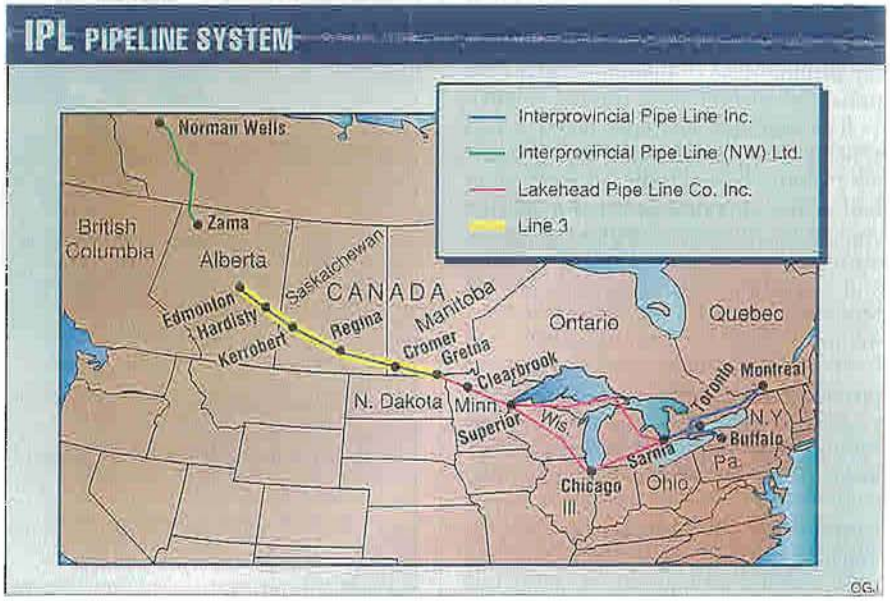
Several defects were identified and repaired, but only one may have been large enough to have failed the hydrotest. At the same time, the lack of any failures during the hydrotest demonstrated that ILI is reliable and overlooks no defects that would have been critical up to 100% specified minimum yield strength (SMYS).

The work afforded the opportunity to compare results from ILI for cracking with a hydrostatic retesting, scheduled weeks after locations pinpointed by the inspection were excavated.

IPL is a wholly owned subsidiary of IPL Energy Inc. Together with affiliate Lakehead Pipe Line Partners L.P., Duluth, Minn., it operates the world's longest liquid hydrocarbon pipeline system.

This system extends 5,100 km from Edmonton to Superior, Wis., and Montreal (Fig. 1). It delivers an average of 1.7 million b/d of liquid petroleum from western Canadian producers to refining centers and markets in eastern Canada and Midwestern U.S.

Fig. 1



Inspection

The BG elastic wave (EW) in-line crack detection vehicle was used to inspect 213.5 km (133 miles) of IPL's Line 3 which runs from Edmonton to the international boundary near Gretna, Man. At this point, it makes an end-on connection with the Lakehead system for further transmission to Superior.

Rigorous analysis of the inspection data, concentrating on the seam weld and surrounding region, identified 73 sites for excavation.

Pressure-retaining sleeves were fitted at 17 locations. Of these, the most severe defect was a 25 mm (1 in.), 40% through-wall, long-seam shrinkage crack. This was the only feature that might have failed under hydrotest to 100% SMYS.

Twelve other cracks, each measuring 20-35% through wall, were sleeved. Minor imperfections were found at the majority of others reported but were not sleeved.

Following completion of remedial work, 198 km of Line 3 were hydrostatically tested at pressures up to 100% SMYS, including 156 km that had been inspected by EW vehicle.

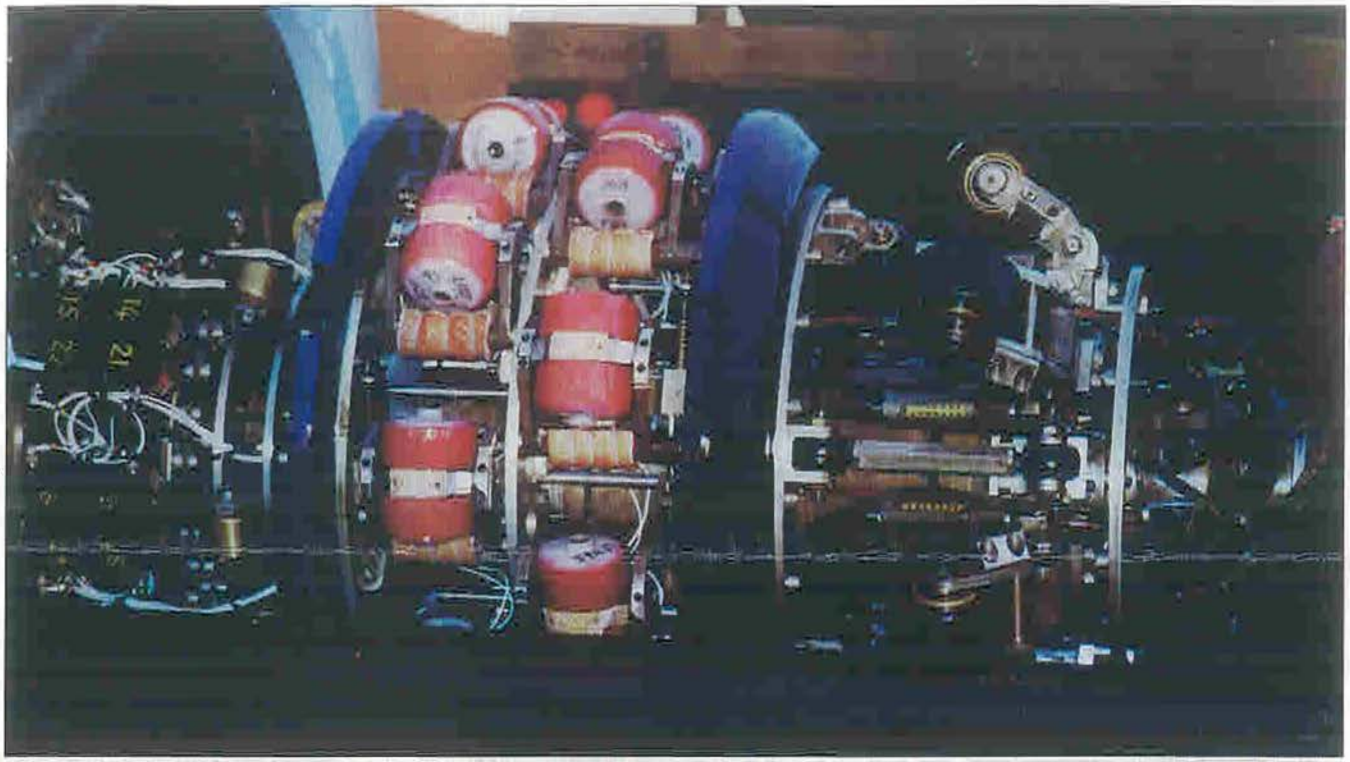
There were no leaks or ruptures under hydrotest, demonstrating the ability of the tool reliably to detect cracks in the seam weld and surrounding region that were smaller than would have been found by hydrotesting alone.

BG Technology developed the EW crack-detection vehicle (Fig. 2), which is owned and operated by Pipeline Integrity International Ltd., Cramlington, U.K. BG Technology, a unit of BG plc, Reading, U.K., conducts research and development in all parts of the gas supply chain, from exploration to burner design.

The EW vehicle detects cracks by transmitting circumferential elastic shear waves at ultrasonic frequencies into the pipe wall. These are generated by transducers in liquid-filled wheels, coupled to the inside pipe surface through soft tires. Spring loading maintains good contact with the pipe wall, which allows the system to be used without slugs in gas pipelines as well as in liquids.

Mann gives further details of the instruments and processes used by the vehicle.[1] Johnston and Thomas[2] and Ward[3] describe operational experience

Based on a presentation to the International Pipeline Conference (ASME), Calgary, June 7—11, 1998.



An elastic wave in-line inspection (ILI) tool has arrived at a pig-receipt station after a run to detect cracks along Interprovincial Pipe Line's Line 3 (Fig. 2).

with the tool.

It has also been shown that the EW tool can detect and characterize defects that were subsequently shown in laboratory burst tests to sustain pressures equivalent to as much as 133% SMYS before failing.[4]

The inspection vehicle used to perform the work described here is known as the Mark 2. It deploys 32 transducer wheels, operating in 16 clockwise-counterclockwise pairs, and fits pipe from 762 to 914-mm (30 to 36-in.) OD. Onboard data recording uses a reel-to-reel tape recorder, and the range is typically 45-50 km, depending on the ultrasonic characteristics of the pipe steel.

A fatigue crack, like this one shown in cross-section from a 1989 Line 3 fatigue crack, can grow gradually over years and fail under normal line operation (Fig. 3).

Line 3

Line 3 of the IPL system is an 864 mm (34 in.) OD pipeline built between 1962 and 1968 with predominantly X-52 Grade DSAW line pipe, 7.1-mm (0.281-in.) W.T. Protection against the ground environment is by single-layer polyethylene tape wrap.

The line transports crude oils of varying density from sweet, light crude to heavy crude with a viscosity of 350 cSt.

The section of Line 3 inspected lies between the tool launcher at Regina, Sask., and receiver at Cromer, Man. This section is 253 km and has three intermediate pump stations at Odessa, Glenova, and Longbank with an average separation of 57 km between stations.

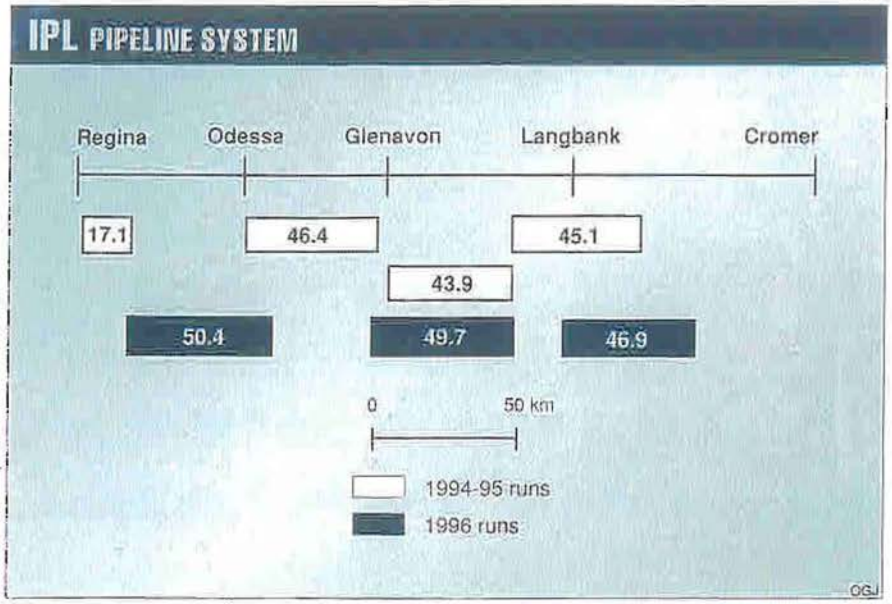
In 1989, Line 3 experienced an in-service rupture downstream of the Langbank, Sask., pump station. This was found to have been caused by fatigue cracking at the base of some light external corrosion (less than 8% through wall), aligned with and close to the DSAW long seam toe.

Examination of the excavated pipe joint found no evidence of metallurgical or structural weakness, and it was concluded that the corrosion had created a concentrator for in-service stress variations. Over many years, this had allowed a fatigue crack to grow so that the joint would fail in normal operation (Fig. 3).

The 1989 failure caused IPL to evaluate the potential for finding existing subcritical cracks by hydrostatic retesting. IPL concluded that, even leaving aside the logistical problems and throughput impact of hydrotesting, nondestructive in-line inspection was potentially far better.

The company based this conclusion on the ability of ILI to find much smaller defects than was possible with hy-

Fig. 4



drotesting. By finding defects at sizes down to early growth phase, IPL would be able to assess the defect population and build up the most effective long-term, risk-management strategy.

Accordingly, IPL began to develop an in-line crack-detection program, including research to study the effects of operating the EW tool in a liquid line and a series of runs with the 864-mm (34-in.) EW tool.

Between June 1995 and February 1996, Line 3 experienced three in-service failures in the Regina-to-Cromer segment. The first was attributed to a unique shape of external corrosion that rendered its size difficult to predict with normal, high-resolution magnetic-flux-leakage (MFL).

The second occurred within 1 km of the 1989 failure and again was found to be a fatigue crack in minor (8% through wall) corrosion at the long-seam toe.

The third failure resembled the first case of elongated corrosion with the addition of a 15% through-wall externally initiated stress corrosion crack at the base of the corrosion.

Following this failure, IPL reached agreement with Canada's National Energy Board (NEB) voluntarily to reduce pressure by 20% on Line 3 between Odessa and Cromer and to conduct an enhanced program of integrity re-evaluation.

The program would ultimately be evaluated and the normal operating pressures restored, pending successful hydrostatic retesting of the 198 km of line where the failures had occurred.

As well as the known problem of fatigue cracking and the potential for general corrosion and environmentally assisted cracking (EAC) under disbonded tape wrap, IPL during 1995 found examples of a novel form of corrosion which came to be known as "narrow axial external corrosion" (NAEC).

It consisted of corrosion grooves with lengths several orders of magnitude greater than their widths. These features were typically very narrow compared to general corrosion, perhaps a few millimeters in width at most.

NAEC often turned up at the toe of the external long seam, initiating and growing under the narrow tent of disbonded polyethylene tape that was an artifact of installation over the long-seam profile. Groundwater could then accumulate in the "tenting" caused by the weld bead under tape wrap.

These corrosive conditions would, of course, also encourage development of EAC, while the corrosion groove itself would be a stress concentrator that could eventually lead to fatigue failure such as at Langbank.

A particular problem with NAEC is that its morphology makes it hard to identify unambiguously and to size by longitudinal field MFL methods as are widely used for metal-loss ILI surveys. Similarly, it is impossible for circumferential EW technology to quantify the severity of such features, although they can be detected.

The discovery of these three separate yet related phenomena (NAEC, cracks inside NAEC, and long-seam fatigue) on Line 3 meant that IPL faced some challenges preparing for the hydrotest. There was also a throughput imperative to achieve a successful hydrotest as soon as possible.

Table 1

EW INDICATIONS: 1994-95

Defect type	No. of locations
External cracks in pipe body	2
External cracks in long seam toe	2
Internal shrink cracks in long-seam centerline	3
Weld defects	3
Inclusion	8
No defects found	4

Table 2

DEFECTS REPAIRED BY SLEEVING IN 1996

Defect type	Sites
Internal long-seam centerline shrinkage crack	10
Internal long-seam toe crack	2
External pipe body crack	1
Corrosion	2
Cold lap	1
Manufacturing grind mark	1

But before hydrotesting could be done, it was necessary to locate and repair all defects that could be critical at the test pressure.

Regina to Cromer

All of Line 3 was inspected for metal loss by Pipeline Integrity International's high-resolution MFL vehicle in 1989-1990 and reinspected in 1993-1994. The Mark 2 EW crack-detection vehicle had made several runs between Regina and Cromer in 1994 and 1995.

Based on analysis of the 153 km of EW data collected then, IPL excavated 22 pipe joints with EW indications. Of these, 7 had crack indications either in the external toe of the long seam, externally in the pipe body, or internally in the center line of the long seam. Table 1 lists the range of defect classifications from the 1994-95 program.

Fig. 4 shows a schematic of the 1994-95 inspections, together with the crack-detection runs made in 1996. In summary, the 1994-95 program had collected data from 153 km, including some short overlaps between runs.

IPL knew, however, that data from some of these runs had been degraded by mechanical damage to the inspection vehicle's transducer wheels. It had been understood that, given the transducers' paired operation, the derangement of one wheel of a pair would not prevent detection and discrimination of a potentially injurious feature.

After early successes in applying the EW technology to Line 3, however, IPL traced the 1995 Langbank failure

Crews excavate a section of Line 3 to verify results of the EW-vehicle analysis (Fig. 5).

to a defect which, although present in inspection data, had been incorrectly classified. An investigation indicated that this was attributable to one wheel of the detecting pair having malfunctioned.

Following this discovery, engineers at BG Technology immediately re-examined the criteria for acceptable data quality, particularly in the seam weld and nearby regions. They generated new data-quality criteria and devised an improved system of checks. In addition, they modified the processes for interpreting data from the seam weld and areas close by. These improved processes are now part of the routine data-analysis procedure.

Working closely with IPL, specialists at BG Technology began 1996 by reanalyzing all existing EW data from Line 3, using the new methods.

This allowed a quantitative picture of the existing data quality to be built up, with particular reference to the seam-weld region considered particularly susceptible to fatigue cracking. With this information, the specialists formulated a program of crack-detection runs for 1996.

New runs

A 1996 program of ILI runs, conducted ahead of hydrostatic testing, used several technologies. The program used both MFL and ultrasonic tools to size metal loss, as well as the EW tool to detect longitudinal cracks.

The EW target inspection ranges were designed to optimize coverage of the seam-weld region between Regina and Cromer. Five runs in the Regina-to-Cromer area took place between Apr. 15 and May 4, 1996.

It should be noted that use of multiple runs was a function of the Mark 2 vehicle's range. The Interim Mark 3 vehicle now in service has a range of up to 150 km/launch.

Data from 176 km, when combined with previous years' inspections, give coverage of 213.5 km out of the 253 km between Regina and Cromer. Fig. 4 shows the coverage from the runs.

Reanalysis of existing data had shown that the seam-weld region was completely covered for the 17.1 km immediately downstream of Regina and for 46.4 km immediately downstream of Odessa. Accordingly, no further inspection of these sections was warranted.

The section from 17 km downstream of Regina to Odessa was programmed for inspection, having never been surveyed previously. In the program, a single pass collected good data between 16 km downstream of Regina and 9.1 km downstream of Odessa.

IPL had concluded that the existing data from Glenavon to Langbank was badly degraded by mechanical damage to the pig, and reinspected this section. Two runs resulted in good-quality data for 49.7 km, starting 6.8 km upstream from Glenavon.

Finally, two runs timed to begin recording slightly before Langbank yielded good seam weld data for 46.9 km, commencing 4.1 km upstream of the Langbank pump station.

While BG Technology and IPL were establishing the program of runs for the crack-detection vehicle, Pipeline Integrity International was addressing the problem of detection of NAEC and cracks inside NAEC.

The details of that approach lie outside the scope of this discussion, but a new MFL tool was developed and used in Line 3 early in April 1996. IPL incorporated results from this new tool in the analysis of EW data, described presently.

Data analysis, cross referencing

BG Technology analyzed new data and reanalyzed previous records and, in this process, used several novel approaches to account for the line's unique characteristics and to make best use of all available data from the various technologies.

Regarding the line's characteristics, IPL agreed that the seam-weld region (defined as 100 mm either side of the long seam, together with the seam itself) was critical. Technicians concentrated analysis on this region, except for joints showing evidence of NAEC or other axially aligned metal loss. They examined the full pipe body for cracking in such joints.

Wherever overlaps existed between runs of the crack-detection pig, the best-quality data for the region of interest were used for primary analysis. Other EW data corroborated this analysis.

Technicians extensively cross-referenced data from all available technologies to build up a complete and accurate picture of the line's condition. For example, when a crack-like feature was flagged in the EW data, IPL checked the MFL metal-loss data at the feature's location.

This allowed compensation for the effects of corrosion to be factored in to the feature's assessment and also ensured that the combined depths of metal loss and cracking would be reported.

Likewise, if the new MFL tool detected any axial corrosion, IPL checked for coincident crack-like indications in the EW record, in case stress concentration had led to fatigue or stress corrosion cracking within the metal loss.

Field excavations; retesting

IPL learned of excavation sites according to an agreed schedule that allowed field crews to be effectively used from April to September 1996. Technicians identified sites by reference to pipeline features and girth welds, from which GPS co-ordinates were derived for accurate location in the field.

Once a site had been uncovered, independent third-party nondestructive evaluation (NDE) specialists examined the reported area of pipe wall and reported.

IPL received reports on 73 sites, all of which were excavated (Fig. 5). Ultrasonic indications were found at all but 5 of these sites and pressure-retaining sleeves were applied at 17 locations (Table 1).

The largest crack found, and the only one which may have failed hydrotesting to 100% SMYS, was a 40% through-wall, 25-mm (1-in.) internal long seam shrinkage crack. Three other sleeved sites had shrinkage cracks between 30% and 35% through wall, while all other sleeved features were less than 25% through wall.

Most of the 56 unsleeved sites were found to have noninjurious features such as cold laps at the long seam or inclusions within the plate. Other indications were from minor features with depth less than 10% through wall and were either ground out, if external, or left without further action.

There had been concern before the inspections that there may have been instances with cracking combined with metal loss, which had motivated the data cross-referencing previously described. In fact, excavation turned up no such defects.

While data analysis and in-field repairs were going on, IPL was also preparing to hydrotest Line 3 between Odessa and Cromer, as required by the NEB.

Major construction was necessary to allow for the intake of 140,000 cu m of water upstream from Regina and also the building of a $5.2 million (Canadian) water-retention pond at Cromer to allow for water cleansing and disposal. This work was completed in time for the hydrotest to begin on Sept. 16, 1996.

IPL designed the hydrotest to include a strength test of 4 hr at a maximum of 860 psi, to be followed by a 4-hr leak test at 120% MAOP. This program was applied concurrently to the eight sections into which the line had been divided by block valves between Odessa and Cromer.

The entire hydrotest was successfully completed within 30 hr of commencing pressurization, with no ruptures or leaks being experienced. The line soon returned to service and, shortly afterwards, IPL received approval to remove the 20% operating-pressure restriction from the section.

The Authors

Miller

Gardiner

Ward

Susan Miller is manager of engineering, pipeline integrity, for Interprovincial Pipe Line Inc., Edmonton, with 18 years' experience in corrosion control and defect assessment of oil and gas producing and transmission facilities.

Miller graduated (1980) from the Nova Scotia Institute of Technology and holds (1985) a Certificate of Applied Sciences from Acadia University.

Michael A. Gardiner is senior scientist in the pipeline inspection technology group at BG Technology. Before moving to BG Technology, he spent 11 years at the British Gas On-Line Inspection Centre (the forerunner of Pipeline Integrity International) and Engineering Research Station. He holds a BS (1982) in physics from Durham University, England.

Clive R. Ward is project team leader for pipeline inspection technology at BG Technology.

He joined British Gas Research & Technology Division in 1977 and spent 2 years working for Acoustic and Vibration Technology as a consulting engineer before rejoining British Gas. His involvement with the elastic wave tool development began in 1987; he became the project's technical manager at BG Technology in 1996 before assuming his current position. Clive holds a BS (1977; honors) in geological geophysics from Reading University, U.K., and is a member of the British Institute of Nondestructive Testing.

Developments

There have been major advances in EW technology since the inspection program reported here.

The Interim Mark 3, as a precursor of the Mark 3 vehicle, which will be introduced later this year, replaced the Mark 2 device early in 1997.

The Interim Mark 3 uses 64 transducers, which may be all of one type to give redundant coverage or of two types to allow the use of different sensor types for improved feature discrimination. Despite the extra transducers, the range was increased to a maximum of approximately 150 km by using new hardware and software. This tool is available in the same range of sizes as the Mark 2.

The Mark 3 vehicle is being developed under a US$5.4 million program sponsored by Canadian Energy Pipeline Association, Gas Research Institute, Pipeline Research Committee International, and Pipeline Integrity International. This development will continue the improvements made in the Interim vehicle by having longer range, up to 96 transducers, variable product bypass, and sizes from 508 to 1,219 mm (20 to 48 in.).

Acknowledgments

The authors thank the group director for research and technology at BG plc and the management of Interprovincial Pipe Line Inc. for permission to publish this article.

References

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3. Ward, C.R., Dunford, D.H., and Mann, A.S., "Inspecting Operational Pipelines for Stress Corrosion and Fatigue Cracking," Institute of Gas Engineers, London, 1993.
4. Maxey, W.A., Mesloh, R.E., and Kiefner, J.F., "Use Of The Elastic Wave Tool to Locate Cracks Along The DSAW Seam Welds In A 32-Inch OD Products Pipeline," Second International Pipeline Conference, Calgary, 1998.

ROUTING AND TRANSMITTAL SLIP

Date: 10/19

TO: (Name, office symbol, room number, building, Agency/Post)	Initials	Date
1. Walt Kelly		
2.		
3.		
4.		
5.		

	Action		File		Note and Return
	Approval		For Clearance		Per Conversation
	As Requested		For Correction		Prepare Reply
	Circulate		For Your Information		See Me
	Comment		Investigate		Signature
	Coordination		Justify		

REMARKS

Per our telephone conversation please find enclosed a copy of the Lakehead Grand Rapids Incident Report.

DO NOT use this form as a RECORD of approvals, concurrences, disposals, clearances, and similar actions

FROM: (Name, org. symbol, Agency/Post)	Room No.—Bldg.
Sandy Cline, Central Region for Ivan Huntoon	Phone No.

5041-102 ☆ U.S. GPO: 1986—181-246/40013

OPTIONAL FORM 41 (Rev. 7-76)
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FPMR (41 CFR) 101-11.206

INCIDENT REPORT

LAKEHEAD PIPE LINE COMPANY, INC.

LINE 3 CRUDE OIL PIPELINE

GRAND RAPIDS, MINNESOTA

MARCH 3, 1991

June 5, 1992

Prepared by: Richard Zachry Barrett
Principal Investigator

Approved by: Ivan A. Huntoon
Chief, Central Region
Office of Pipeline Safety

INCIDENT REPORT
LAKEHEAD PIPE LINE COMPANY, INC.
#3-34 INCH CRUDE OIL PIPELINE
GRAND RAPIDS, MINNESOTA
MARCH 3, 1991

I. Incident Synopsis

The Lakehead Pipe Line Company (Lakehead), headquartered at 119 N. 25th Street East, Superior, Wisconsin, operates the United States portion of Line 3 of the Interprovincial/Lakehead pipeline system. Interprovincial Pipe Line Limited (Interprovincial), headquartered at 10201 Jasper Avenue, Edmonton, Alberta, Canada, operates the Interprovincial Control Center and Canadian portion of Line 3. Line 3 is a 34-inch common carrier crude oil pipeline that originates in Edmonton, Alberta, Canada (MP 0.00) and reaches a terminus in Superior, Wisconsin (MP 1096.95). Lakehead's pipeline system continues the transportation of crude oil from the Superior terminal to the Midwestern United States and Eastern Canadian refineries, where it is processed into refined products.

[redacted] As of November 6, 1991, 39,800 barrels of the released crude oil from the pipeline have been recovered and returned to the pipeline. The 700 remaining barrels are estimated by Lakehead to be contained in the soil removed from the leak site vicinity for incineration. The estimated total property damage due to the release is $7,458,000.

[redacted] The mechanisms which initiated and propagated the cracks were identified as [redacted]

Floodwood, the pump station upstream of the Superior terminal, was unavailable for operation during the failure as a result of an electrical fault. The electrical fault rendered the Interprovincial Control Center without the ability to start pumps or monitor pressure and flow rate data at the Floodwood pump station.

At approximately 10:00 AM MST, Line 3 was configured by the Interprovincial Control Center Operator to make deliveries into the Superior terminal causing the pipeline to be operated from Hardisty to Superior. [redacted]

The Senior Operator after reviewing historical operating records, pump unit output differential, and conferring with an off-duty Interprovincial [redacted] This would account for the indicated 454 psig drop in discharge pressure identified at the Deer River pump station.

At approximately 11:28 AM MST, the Interprovincial Operator increased the Superior holding pressure from 100 psig to 150 psig in an attempt to repack the fluid column. The flow rate incoming to Clearbrook was also reduced to avoid a large pressure increase when the presumed separated fluid column became repacked.

At 11:39 AM MST the communication to the Floodwood pump station was restored. The Interprovincial Control Center Operator, for Line 3, noted a low discharge pressure reading at the Floodwood pump station and determined that the fluid column was separated between the Floodwood pump station and Superior terminal. [redacted]

From 12:00 noon MST till 12:12 PM MST, [redacted] The pipeline pressure had not responded as the Interprovincial Operator had expected and he requested that the flow rate into the Superior terminal be checked and verified. [redacted]

[redacted] Northern Minnesota Utilities employee of an identified failure in Lakehead's Line 3 near Grand Rapids, Minnesota. The crude oil from the release primarily collected in a field adjacent to the Itasca Community College, but also migrated 3/4 of a mile down a 16-inch tile drainage line which emptied into the Prairie River. The crude oil in the Prairie River was located approximately two miles upstream of the Mississippi River. The Prairie River was covered with ice and had small areas of slow flowing open water. Most of the crude oil entering the Prairie River was sustained on top of the ice and blocked by ice flows. Nearby residents were evacuated from 2:45 PM MST to 8:00 PM MST. Containment and clean-up efforts began by late afternoon March 3rd, with three Lakehead crews and several contractors on-site.

II. Facts

A. Site Description

[redacted] This location is approximately 1/4 mile west of the Itasca Community College Campus and 1/4 mile north of Highway 169, just east of the Grand Rapids, Minnesota, city limits. The failure site is approximately 14.7 miles downstream of the Deer River pump station and 34.4 miles upstream of the Floodwood pump station.

The pipeline failure occurred on a flat low land pasture, originally a wet land owned by the University of Minnesota. The pasture was frozen and covered with snow with approximately three acres covered with pooled crude oil (See Appendix A for photos of leak site). A 16-inch tile drainage pipe that had been installed to drain the field allowed the released crude oil to flow into the Prairie River, a tributary of the Mississippi River.

The crude oil in the Prairie River was located approximately two miles upstream of the Mississippi River. The Prairie River was covered with ice and had small areas of slow-flowing open water. Most of the crude oil entering the Prairie River was sustained on top of the ice and blocked by ice flows (See Appendix B for photos of crude oil in Prairie River). Lakehead deployed five booms downstream of the spill site; however, oil was never detected at the boom sites.

The elevation of the leak site (MP 1009.90) is 1290 feet above sea level. Elevations of Deer River (MP 995.83) and Floodwood (MP 1044.33) are 1291 and 1251 feet above sea level respectively. The Superior terminal (MP 1096.95) has an elevation of 653.5 feet (See Appendix C for Elevation Profile).

B. System Description

1. IPL/LPL System.

Interprovincial Pipe Line Limited (IPL) and its wholly owned subsidiary, Lakehead Pipe Line Company, Inc.(LPL), own and operate the largest petroleum pipeline system in the world, with

7,213 miles of pipeline linking 3,702 right-of-way miles of international land.

The IPL/LPL system consists of three parallel lines from Edmonton to Superior; two lines from Superior to Sarnia, Ontario--one via the Straits of Mackinac and one via Chicago; two lines from Sarnia to the Toronto area in Ontario with a lateral extension to Buffalo, New York, and a second lateral to Nanticoke, Ontario; and one line from Sarnia to Montreal (See Appendix D for System Map).

The line capacity for the system is approximately 26.9 million barrels of petroleum. The system utilizes 87 pumping stations with a combined total of 458 electric pumping units (1,129,286 hp) to move an estimated 1,461,100 barrels per day (BPD) of product throughout the system. The system embodies 34 feeder pipelines, 22 delivery locations, and 40 active shippers which provide the system with over 70 crude oil and product types for transportation. The Lakehead Pipe Line Company serves as the operating company for the United States portion of the pipeline. This system transports crude oil and other petroleum resources, primarily from the oil producing areas of Western Canada to refining centers and markets in the Mid-Western United States and Eastern Canada.

The control system used to operate the pipelines out of Edmonton consists of the main (central) computers and the site computers located at each pump station. There are four main computer systems. Two are located in the computer room at Interprovincial Control Center in Edmonton and the other two are located at the Interprovincial Edmonton terminal. The computers at the Edmonton Terminal are used for backup in case of trouble with the downtown units. From these locations, the pipeline controllers can remotely control the operation of the pumping units and monitor the operation of the system via the SCADA system (Supervisory Control and Data Acquisition). The communications between the main (central) computers and the terminal or station computers is accomplished by leased telephone circuitry (See Appendix F for Control System flowchart).

2. IPL/LPL Line 3 System.

The Interprovincial/Lakehead Pipe Line System Line 3, is a [redacted] Alberta, Canada, (MP 0.0) and reaches a terminus in Superior, Wisconsin, (MP 1096.95). The United States/Canadian border for Line 3 is located at Milepost 773.72 (See Appendix F for Line Map and Elevations for Line 3). The Interprovincial Control Center, as previously described, for Line 3 is located in Edmonton, Alberta, Canada.

The maximum design throughput for Line 3 is 673,000 BPD. The crude oil transported by the pipeline consists of various batches, 42 percent of which are heavy crude oils, 34 percent are light crude oils, 17 percent are medium crude oils, and 7 percent are synthetic crude oils. The injection and delivery points for the pipeline are identified by the diagram in Appendix F. Breakout tankage for the pipeline is located at Hardisty, Kerrobert, Regina, Clearbrook, and Superior (See Appendix G for System Tankage).

The construction of Line 3 was effected in progressively looped sections of 34-inch diameter pipe affixed to the system's No. 2-26" pipeline (Line 2) from 1962 to 1968. Sections of Line 3 have been looped with 48-inch pipe (initiated 1972). When the 48-inch loops were added, the original 34-inch sections of Line 3 became part of Line 2 (See Appendix H for Typical Crossover).

Lakehead's Line 3 pipeline was constructed of pipe manufactured by the Electric Weld and Submerged-arc Weld processes. The pipe manufacturers for the electric weld process were A.O. Smith (179 miles of flash weld) and Canadian Phoenix Steel & Pipe Ltd. (2 miles of electric-resistance weld). The submerged-arc welded pipe was supplied by U.S. Steel (141 miles) and Kaiser (2 miles).

Line 3 is a telescoped pipeline with wall thicknesses of 0.500, 0.375, 0.344, 0.312, and 0.281 inches. The pipe in Line 3 was predominantly manufactured to API 5LX-52 specifications.

The discharge pressure control settings at pump stations vary due to hydraulic gradients along the route of the pipeline, but are set to maintain line pressures within the design parameters of the system.

C. Failed Pipe Data

[redacted] The pipe was manufactured to API Grade 5LX-52 line pipe specifications and was purchased from U.S. Steel Corporation in 1967. The pipe is a straight-seam pipe with a double submerged-arc longitudinal weld (DSAW).

The pipe failed in the heat-affected zone at the toe of the double submerged-arc longitudinal weld. The length of the failure was approximately 64-inches with an approximate width of 6-inches as measured at the widest point of the failure (See Appendix I for photos of failure). The failure and longitudinal seam were oriented in the 9-o'clock position looking upstream toward the Deer River pump station.

The maximum operating pressure of Line 3, between the Deer River and Floodwood pump stations, is 611 psig and is based on a 1976 minimum hydrostatic test pressure of 764 psig. At the time of the incident MP 1009.90, the point of the pipeline failure, was operating at a calculated pressure of 473 psig. The estimated pipe temperature at the time of failure was 56 degrees Fahrenheit.

D. Cathodic Protection Data

The pipeline was cathodically protected by the use of rectifiers and magnesium anodes. The pipeline coating is a Polyken tape with a Kraft outer wrap. Internal corrosion inhibitors were not used in the pipeline.

The October 1990 annual corrosion survey potentials were more negative than -1.0 VDC in the vicinity of the leak area. Instant-Off pipe-to-soil potential readings were taken at the failure site and found to be more negative than -1.0 VDC. An internal inspection tool survey performed in August of 1989 did not indicate any suspected areas of corrosion for the pipeline in the leak vicinity. The Battelle metallurgical report revealed that minimal corrosive activity appeared to have occurred on the weld reinforcement, but was not seen on the plate surface of the pipe. In addition, the Battelle report indicates that corrosion was not a factor in the Line 3 failure.

E. Leak History

The pipeline has experienced a total of 24 leaks due to longitudinal seam incidents in the Gretna to Superior section of pipeline since 1973, including the March 3, 1990, failure near Grand Rapids, Minnesota. The pipeline has experienced 9 failures due to causes other than longitudinal seam incidents in the Gretna to Superior section of pipeline since 1972. Of the 24 seam-related failures, 2 were reported to be pressure test failures (See Appendix J for list of failures).

Two failures on Lakehead's 26" diameter line and one failure on their 34" diameter line in 1973, each involving a longitudinal seam, resulted in an investigation by the Office of Pipeline Safety. Lakehead revised operating procedures, installed additional controls, and embarked on an hydrostatic testing program to address factors that were believed to have contributed to the failures. Hydrostatic testing of the 34" diameter line was begun in 1974 and completed in 1976.

The Office of Pipeline Safety additionally investigated the circumstances of longitudinal seam failures on the 34" diameter line that occurred in 1979 and 1980. Lakehead temporarily reduced operating pressures on the line sections involved in the failures and agreed to hydrostatic testing of these sections.

The hydrostatic testing program was conducted in 1981 and included sections of pipeline from MP 773.72 to MP 848.15 and from MP 909.27 to MP 933.43.

F. Failure Metallurgy

A 40.75-foot section of the pipeline containing the rupture and a girth weld on each end used to join the failed section of pipe to the adjacent pipes in the pipeline were sent to Battelle in Columbus, Ohio, for metallurgical analysis. Battelle's (data) report indicated the following:

Two crack systems were present in the failure. The initiating crack, was a long, shallow surface crack extending from the inside diameter notch produced at the toe of the pipe's longitudinal weld seam. This crack was at least 64-inches in length and extended nearly the total length of the propagating fracture. The crack's average depth was 0.010-inches; however, near the center of the failure origin the crack's depth was approximately 0.030-inches. The mode of propagation was transgranular, which is typical of a fatigue mechanism. The crack is believed to have initiated and propagated due to the static and dynamic stresses produced during the shipment of the pipe.

The second crack, the fracture origin crack, appeared to have grown from the deeper transportation-grown surface crack described above by a fatigue mechanism driven by the cyclical operation of the pipeline. This crack was 6-inches in length and grew to nearly a depth of 0.281-inches over a length of 2.5 inches at the outside diameter surface. There was no evidence that corrosion was a factor in the failure (See Appendix K for metallurgical report).

G. Spill Size

The pipeline release resulted in 40,500 barrels of crude oil being spilled with approximately 20 percent of that amount being spilled into the Prairie River. As of November 6, 1991, 39,800 barrels of the released crude oil from the pipeline have been recovered and returned to the pipeline. The 700 remaining barrels are estimated by Lakehead to be contained in the soil removed from the leak site vicinity for incineration. Lakehead estimated that total property damage, including cleanup costs, due to the release is $7,458,000. These costs were broken down as follows:

Oil Recovery	$ 735,000
Oil Lost	14,000
Oil Cleanup	6,100,000
Oil Incineration	600,000
Area Property Damage . . .	9,000

III. Description of Failure

A. Events Preceding Failure.

On March 2, 1991, at approximately 10:00 PM MST, the Interprovincial Control Center Operator for Line 3 after completing a delivery into the Clearbrook pump station tankage, began to start pumps at the downstream Deer River and Floodwood pump stations to initiate a delivery into the Superior terminal. At 10:41 PM MST, Floodwood pump station unit #2 had completed sequencing to an "on" status. At 10:55 PM MST, a cable fault in an electrical feeder between the Lakehead power transformer and the Line 2 switchgear cubicle occurred rendering the pump station without power (See Appendix L for Schematic). The lack of electrical power to the Floodwood pump station caused the only pump operating on Line 3, unit #2, to lock out, thereby causing the flow of crude oil to bypass the pump station. At 11:53 PM MST, the Interprovincial Control Center lost communication to the Floodwood pump station due to the reserve battery power system voltage dropping below the SCADA computers threshold limit. The loss of communication at the Floodwood pump station caused the Deer River pump station, the next upstream pump station to Floodwood, to go into the zero flow condition. The zero flow condition limits the pressure at the next upstream station, in relation to the station with the communication outage, to a designed pressure that will assure the maximum operating pressure downstream of the last pump station with communication will not be exceeded when downstream pump stations are not in operation. The zero flow condition is based on the weakest element in the system downstream of the last pump station with communication. The Deer River pump station continued to operate in this mode until approximately 5:25 AM MST on March 3 when the pump station was shut down as a delivery into the Superior terminal was completed. The pipeline then began operations to make a delivery into Clearbrook tankage (See Appendix M).

On March 3, 1991, at approximately 7:30 AM MST, the Interprovincial Control Center Operator for Line 3 noted that low discharge pressures for the Deer River and Cass Lake pump stations had occurred that were coupled with a low Superior holding pressure during the previous shut down of the pipeline at the completion of the delivery into Superior. These conditions indicated to the Interprovincial Control Center Operator that a fluid column separation had occurred between the Floodwood pump station and the Superior terminal following the shut down of Line 3.

At approximately 10:05 AM MST, the Interprovincial Control Center Operator began starting the Clearbrook to Superior section of Line 3 by injecting into the pipeline at Clearbrook from tankage (See Appendix M for Flow Schematic). At 11:06 AM

MST, the Clearbrook pump station injection into Line 3 from tankage and delivery from Line 3 into tankage at Clearbrook were terminated. This and other changes on the pipeline resulted in Line 3 being operated from Hardisty to Superior (See Appendix O).

B. The Failure

A decrease in discharge pressure of 366 psig at the Deer River pump station occurred between 11:18:54 MST and 11:19:40 MST. At approximately 11:20 AM MST, the Interprovincial Control Center Operator noted a sudden increase in throttling at the Deer River pump station and immediately alerted the Interprovincial Senior Control Center Operator of the irregularity.

C. Actions After Failure

The Interprovincial Senior Operator after reviewing historical operating records and pump unit output differential attributed the situation to possibly one of three causes: 1) A fluid column separation between the Floodwood pump station and the Superior terminal, 2) A discharge pressure transmitter error at the Deer River pump station, or 3) A pipeline leak. Of the three possible causes, column separation was foremost in the Interprovincial Senior Operator's mind. To obtain a second opinion, the Interprovincial Senior Operator consulted an off-duty Interprovincial Senior Operator by telephone. After analysis, the off-duty Interprovincial Senior Operator concurred that a fluid column separation had occurred. In addition, the Interprovincial Senior Operators believed, an instrumentation error had occurred at the Deer River pump station that accounted for the 454 psig drop in Deer River discharge pressure between 11:18:54 AM MST and 11:20:01 AM MST. The Superior holding pressure was increased from 100 psig to 151 psig at approximately 11:28:51 AM MST to repack the column, and the flow rate incoming to Clearbrook was reduced through setpoint control to avoid a large pressure increase when the presumed separated column became repacked.

At 11:39 AM MST, the Floodwood pump station communication was restored. The Interprovincial Control Center Operator for Line 3 noted a low discharge pressure reading at the Floodwood pump station and concluded that the fluid column was separated between the Floodwood pump station and Superior terminal. At 11:45 AM MST, the off-duty Interprovincial Senior Operator contacted the Interprovincial Control Center for an update of the situation. The validity of the pressure readings at the Floodwood pump station were questioned due to the possibility of the pump station being isolated because of the earlier cable fault problem. In a further attempt to repack the fluid column, the holding pressure at Superior was increased at 12:00 noon MST from 151 psig to 167 psig; at 12:07 PM MST from 167 psig to 188 psig, and at 12:12 PM MST from 188 psig to 207 psig.

At 12:20 PM MST, the pipeline pressure had not responded as the Interprovincial Senior Operator had expected. The Interprovincial Senior Operator contacted the off-duty Interprovincial Senior Operator and it was deemed necessary to request the receiving tank's level to be checked at the Superior terminal. The electronic gauges on the tank at the Superior terminal indicated that the incoming flow rate for Line 3 into the terminal was 9,435 bbl/hr. The flow rate for Line 3 downstream of Clearbrook pump station/terminal, as estimated by pump differential, was 25,162 bbl/hr. The Interprovincial Senior Operator requested Superior to confirm the incoming flow rate with a manual steel tape tank gauge. Superior confirmed the incoming flow rate was correct at 12:31 PM MST and the shut down of Line 3 commenced immediately. The last pumping unit on Line 3 was stopped at 12:35 PM MST. Following shutdown, control center personnel continued to review and analyze their data to determine the cause of the abnormal operating condition indications that had been received.

At 1:25 PM MST, the Interprovincial Control Center discussed the situation with Lakehead Pipe Line management at Superior and requested a line patrol downstream of the Deer River pump station.

An employee of Northern Minnesota Utilities contacted the Lakehead Superior Control Center and reported a crude oil release near the Itasca Community College at 1:43 PM MST. At 2:31 PM MST, the Deer River and Floodwood pump stations remote controlled sectionalizing valves were closed by the Interprovincial Control Center. The Lakehead manual gate valve (MP 1010.57) on the west side of the Prairie River was closed at 2:44 PM MST.

The crude oil from the release primarily collected in a field adjacent to the Itasca Community College, but also migrated 3/4 of a mile down a 16-inch storm drain line which emptied into the Prairie River. Nearby residents were evacuated from 2:45 PM MST to 8:00 PM MST. Containment and clean-up efforts were begun by late afternoon March 3rd, with 3 Lakehead crews and several contractors on-site. Once access to the leak site was established, Line 3 was exposed and drained, revealing a split, 64-inches in length by 6-inches in width as measured at the widest point, in the heat affected zone of the longitudinal seam. The pipeline was repaired by removing the failed section of pipe and replacing it with a section of pre-tested pipe. Line 3 was returned to service at a reduced pressure at 2:54 AM MST on March 7, 1991.

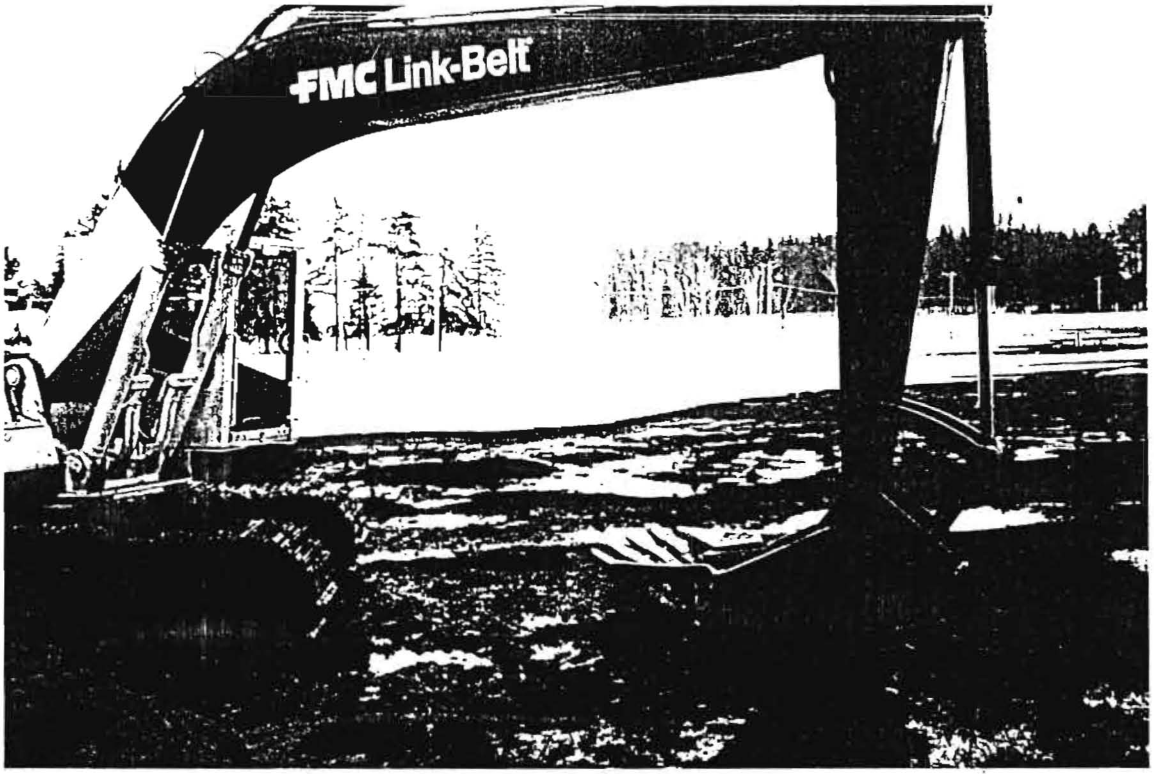
APPENDIX A

FAILURE SITE MP 1009.90 MARCH 4, 1991 - GRAND RAPIDS, MINNESOTA.

LOW LAND PASTURE WITH 3 ACRES COVERED WITH POOLED CRUDE OIL.

FORMER WET LAND OWNED BY THE UNIVERSITY OF MINNESOTA.

FAILURE AREA



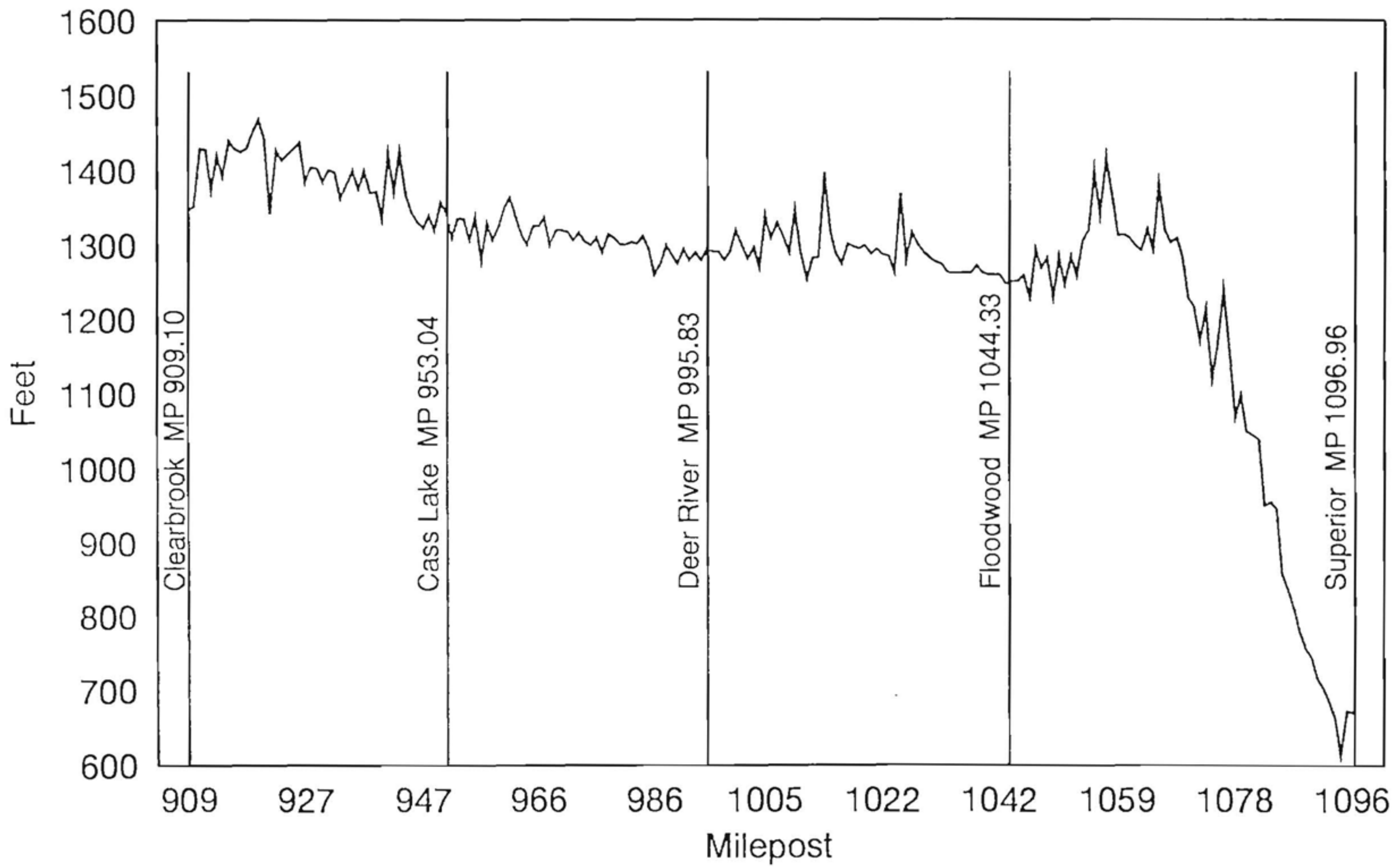
FAILURE AREA

DRAIN-UP OF FAILED PIPE AND FAILURE AREA IS UNDER WAY.

APPENDIX B

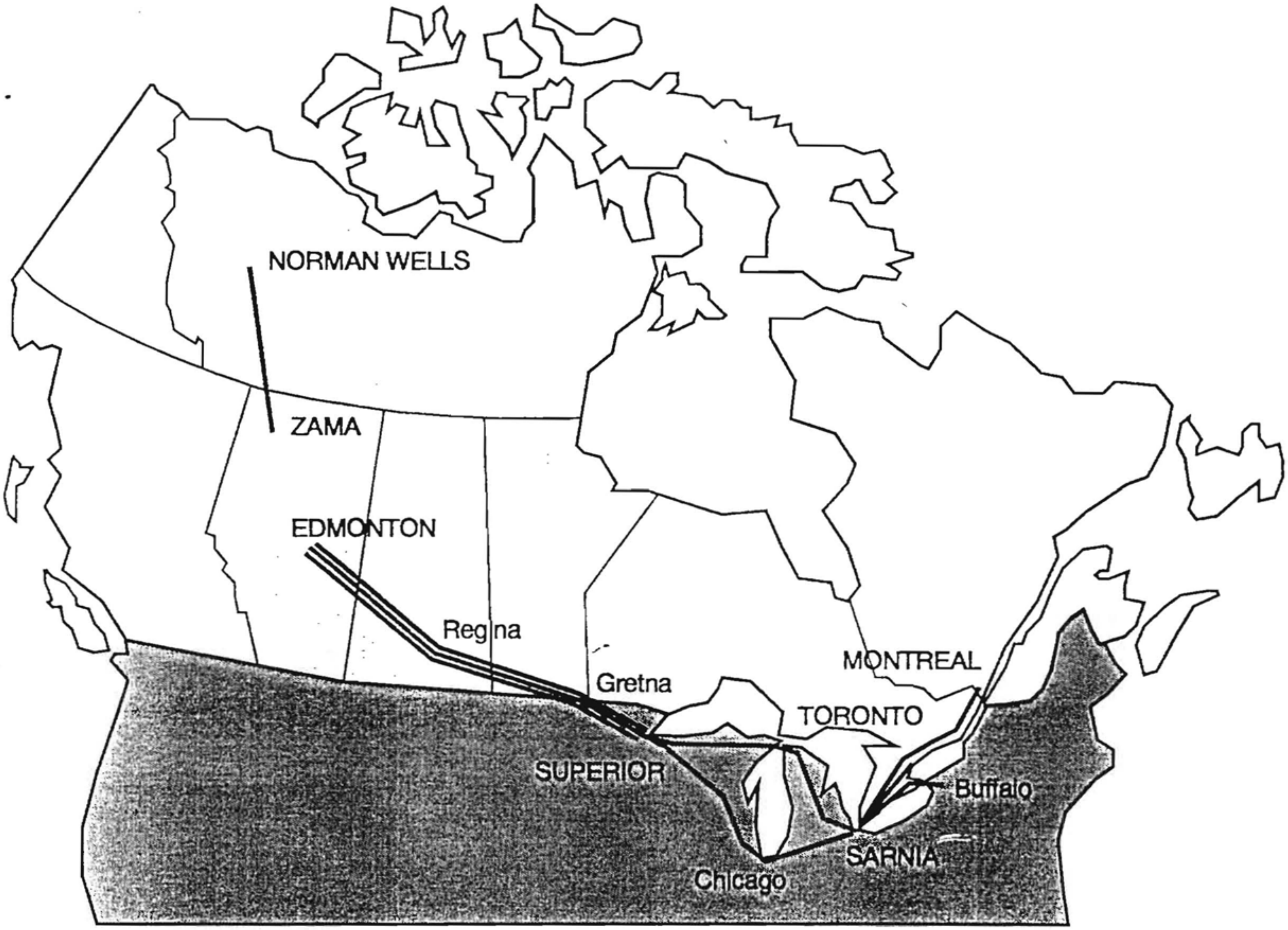
APPENDIX C

ELEVATION PROFILE
CLEARBROOK TO SUPERIOR

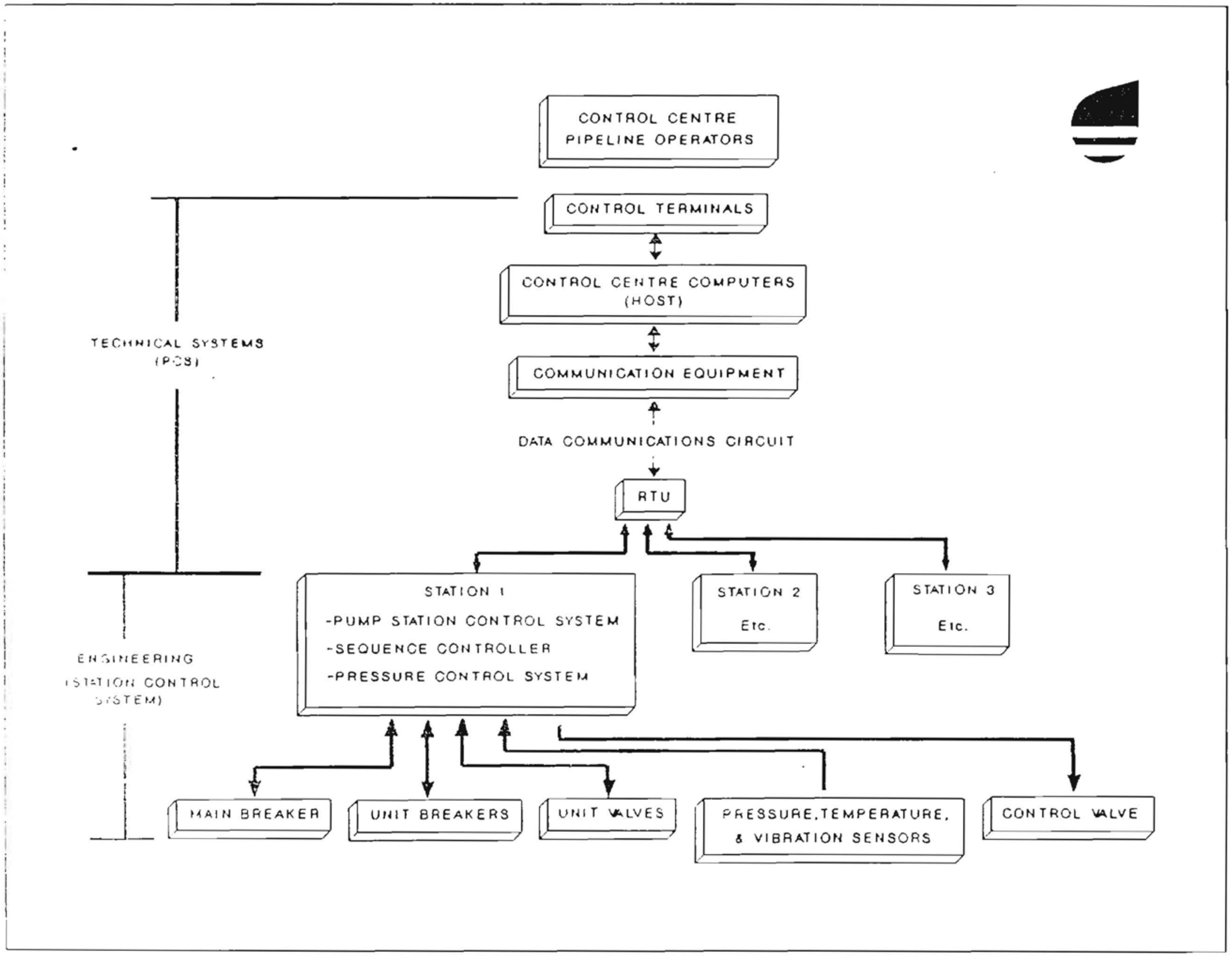


APPENDIX D

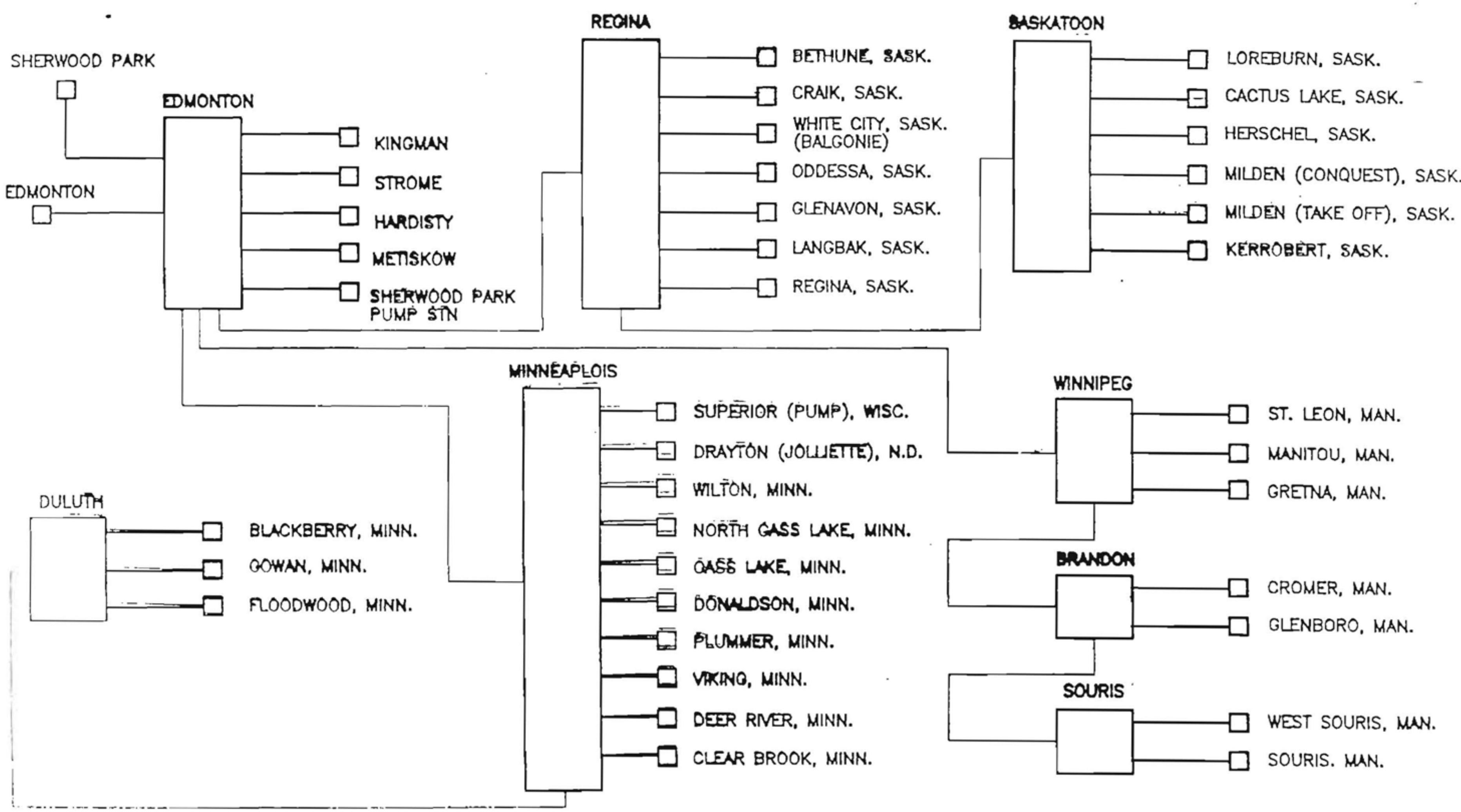
INTERPROVINCIAL PIPE LINE COMPANY



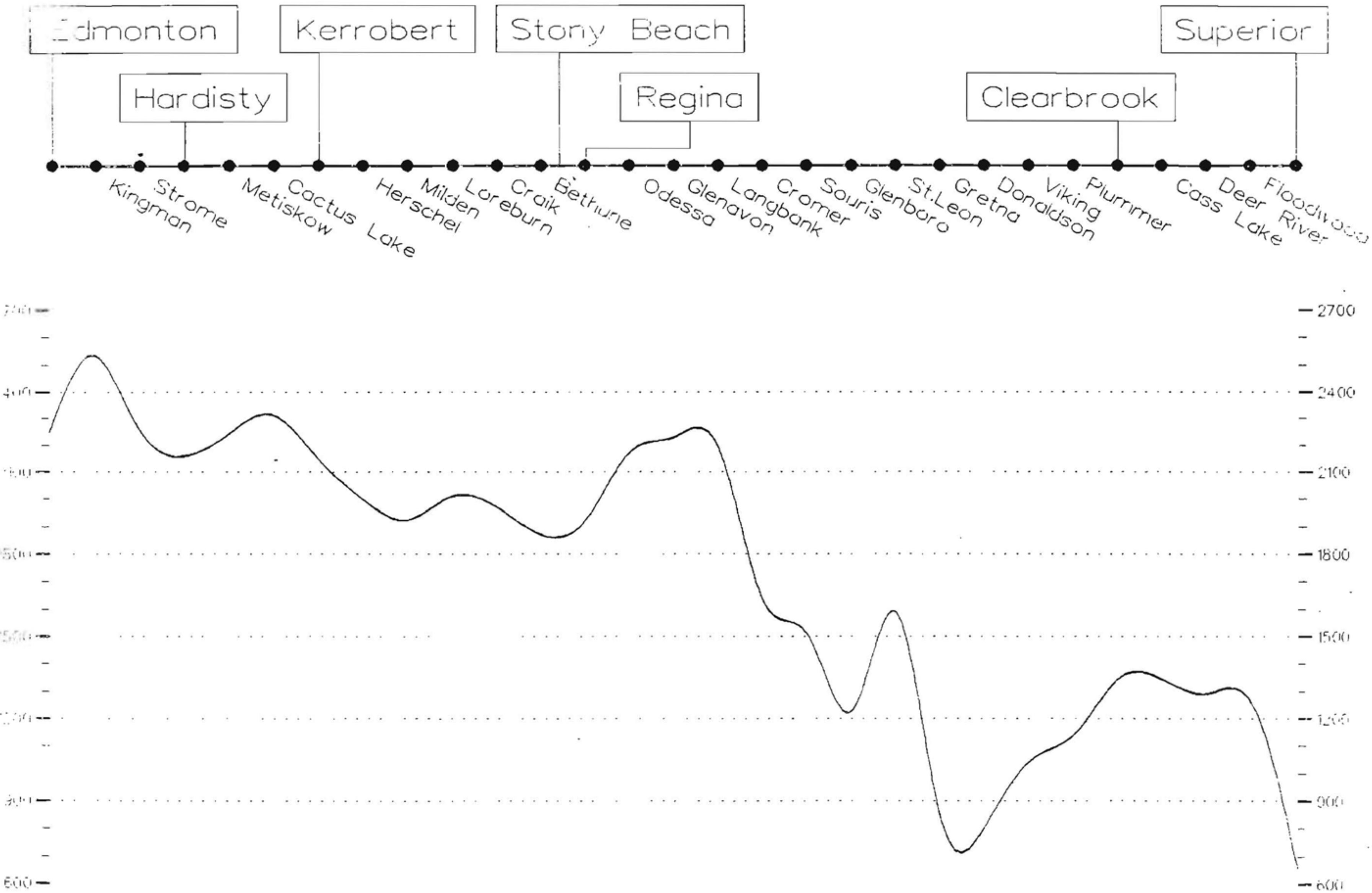
APPENDIX E


CONTROL CENTRE
PIPELINE OPERATORS
CONTROL TERMINALS
CONTROL CENTRE COMPUTERS
(HOST)
COMMUNICATION EQUIPMENT
DATA COMMUNICATIONS CIRCUIT
RTU
TECHNICAL SYSTEMS
(PCS)
STATION 1
-PUMP STATION CONTROL SYSTEM
-SEQUENCE CONTROLLER
-PRESSURE CONTROL SYSTEM
STATION 2
Etc.
STATION 3
Etc.
ENGINEERING
(STATION CONTROL
SYSTEM)
MAIN BREAKER
UNIT BREAKERS
UNIT VALVES
PRESSURE, TEMPERATURE,
& VIBRATION SENSORS
CONTROL VALVE

I.P.L. NETWORK LAYOUT (4800 BPS)
5/FDDC/314297//ABGT



APPENDIX F

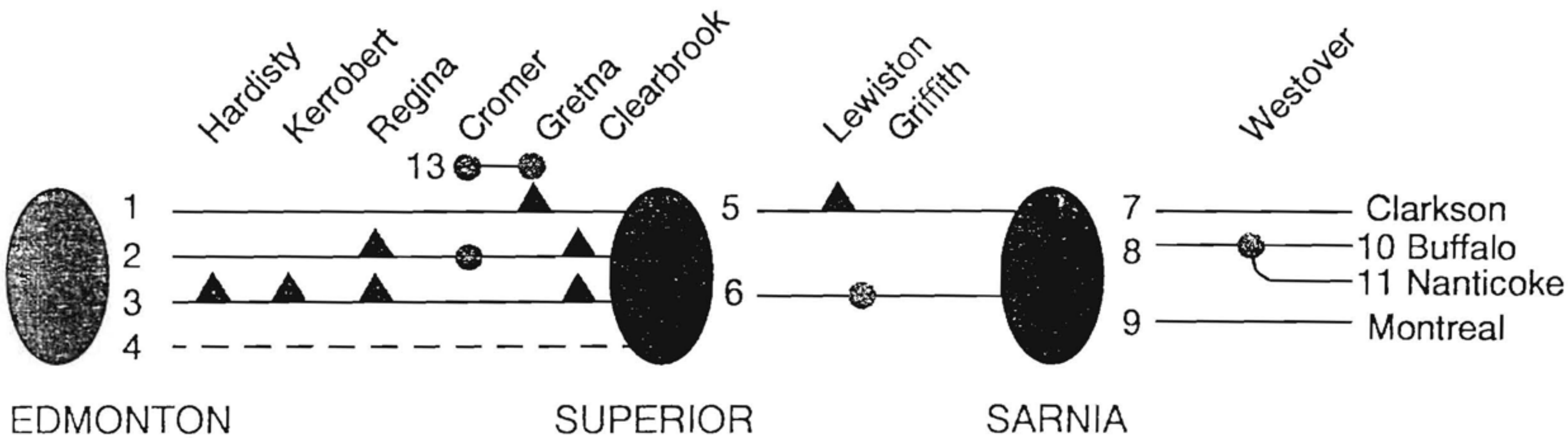


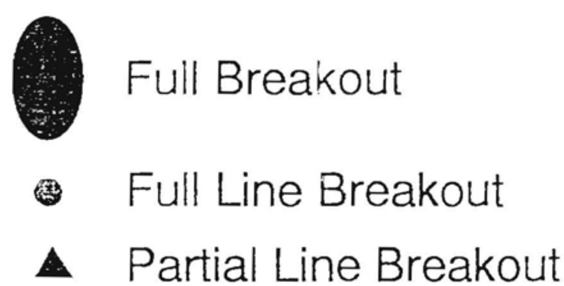
LINE 3 OVERVIEW   Injection/Delivery Locatio

APPENDIX G

SYSTEM TANKAGE

18,000,000 BBLS
126 TANKS

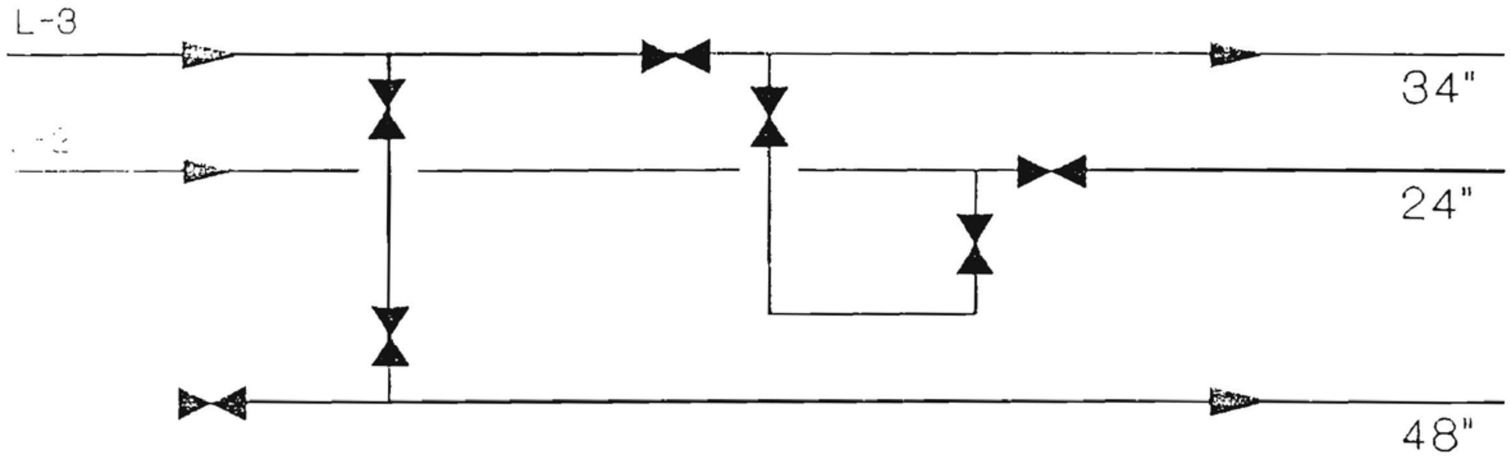




KEY TANKAGE LOCATIONS

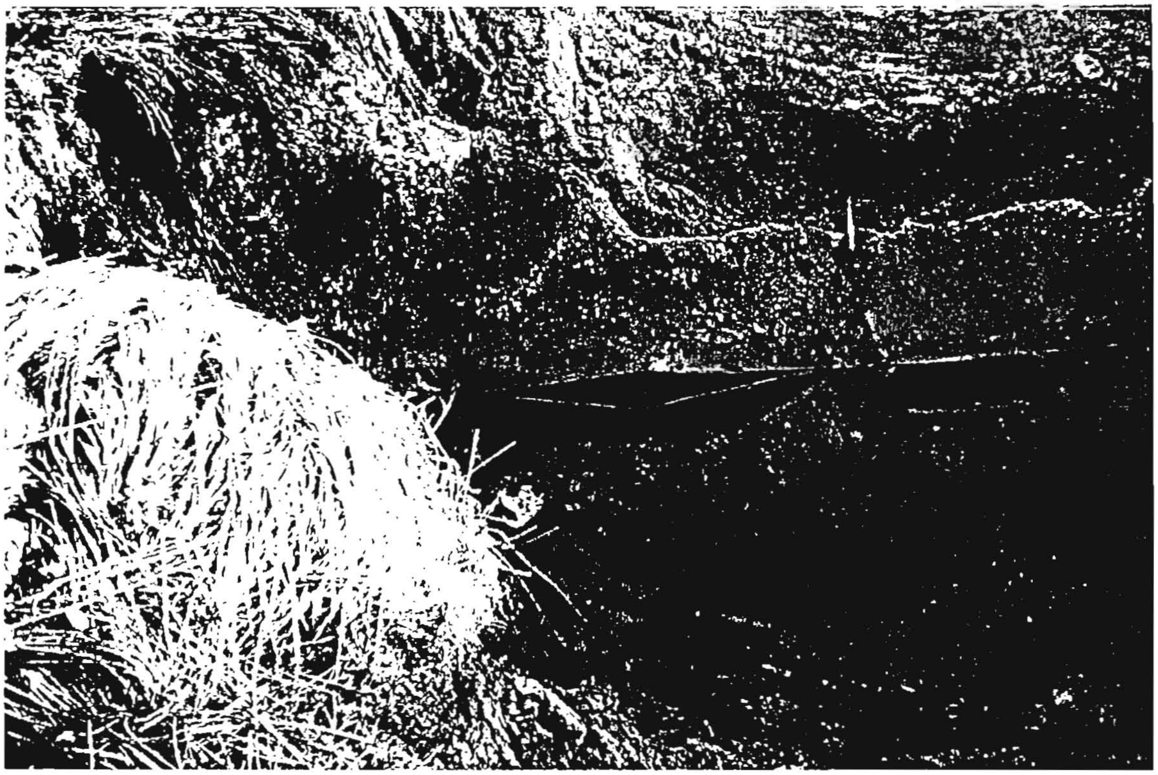
	Bbls.
Edmonton	4,631,000
Superior	4,584,000
Sarnia	3,030,000
Griffith	2,202,000
Cromer	1,125,000

APPENDIX H

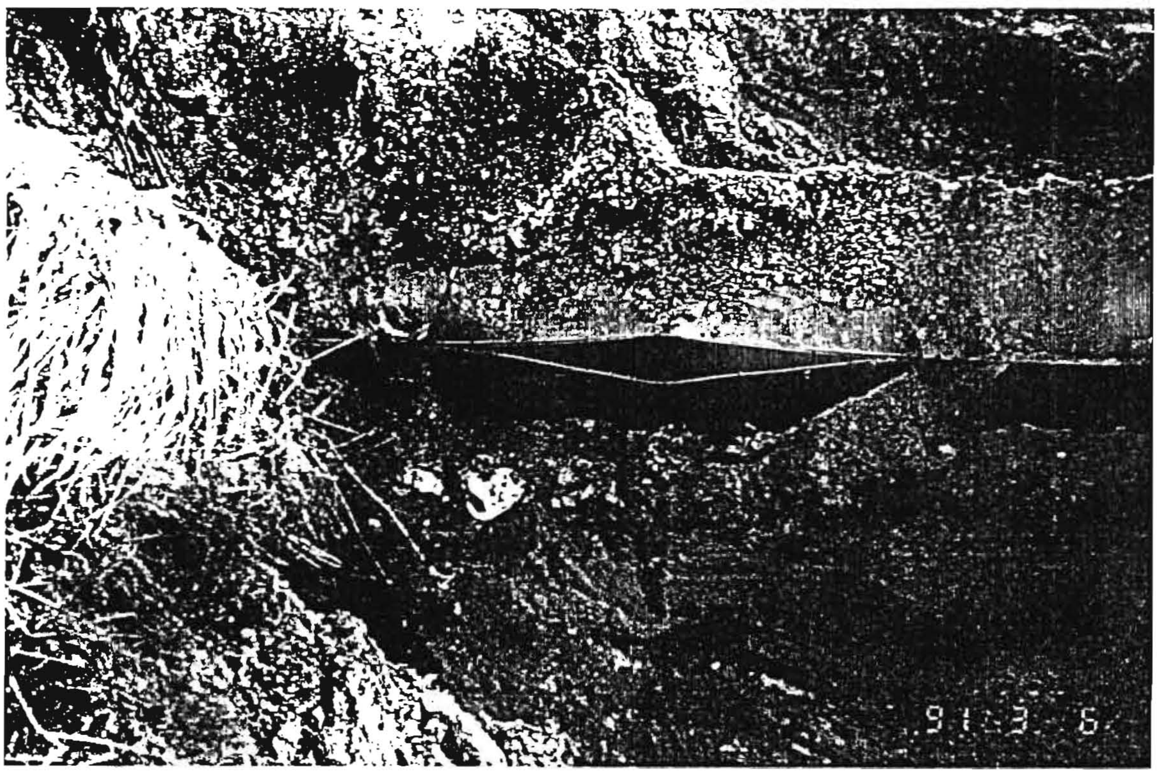


TYPICAL 24"/34"/48" CROSSOVER

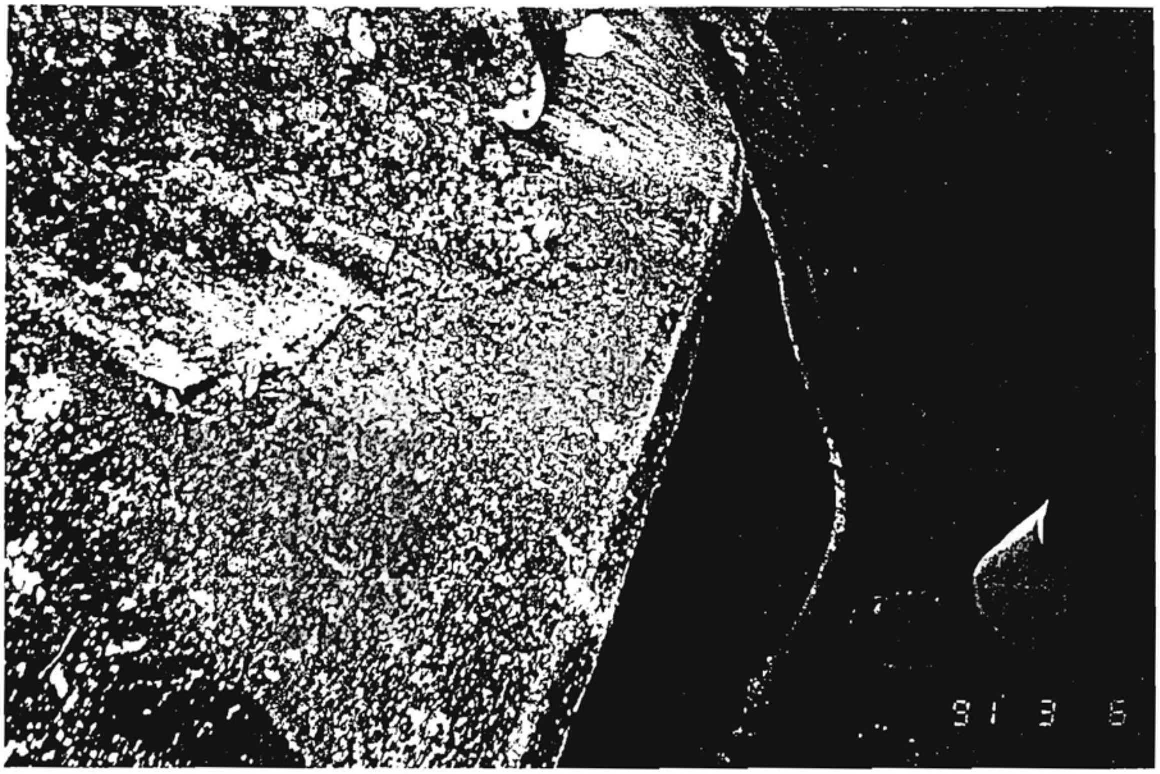
APPENDIX I



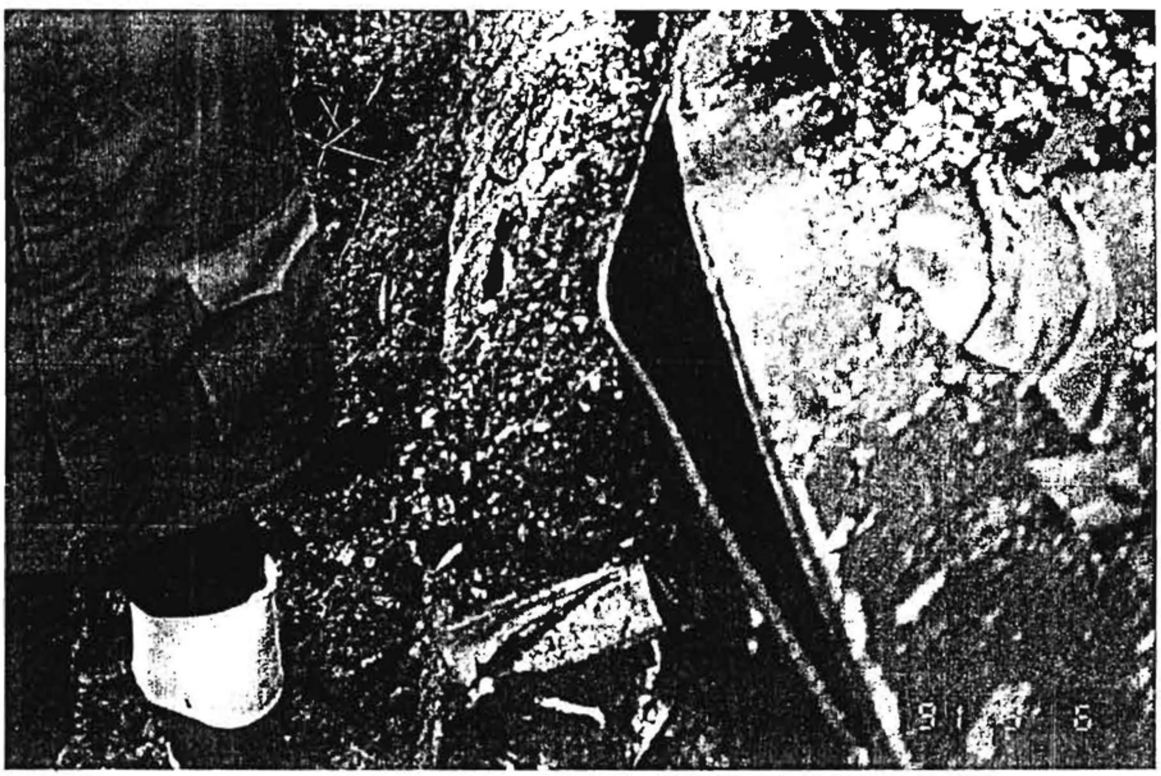
LINE 3 - 34-inch, 0.281-inch wall, API 5LX-52, U.S. STEEL
MARCH 3, 1991, FAILURE GRAND RAPIDS, MINNESOTA.



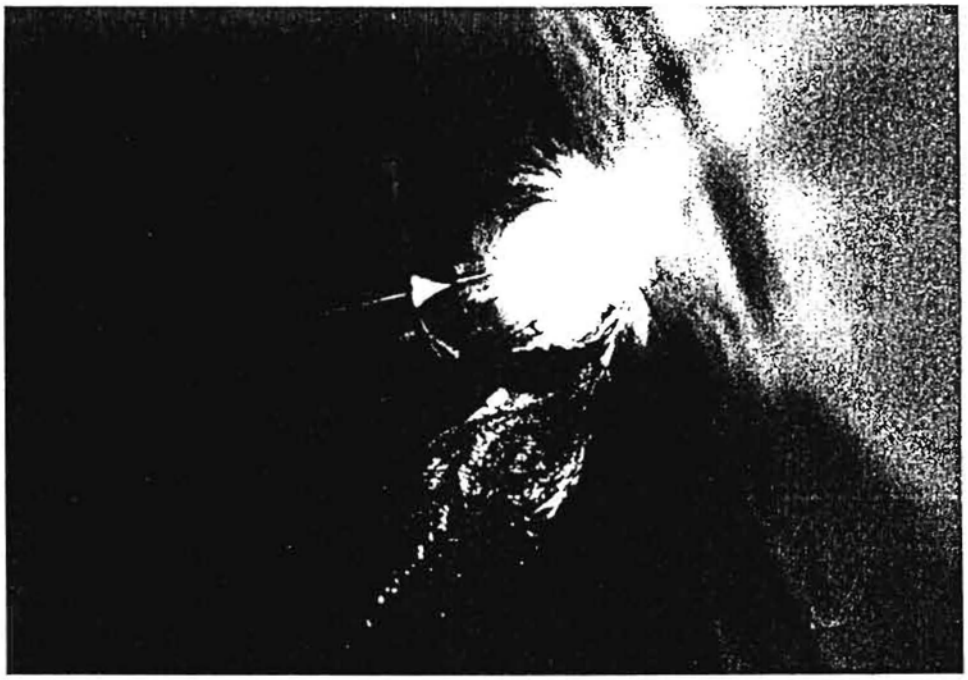
34-inch FRACTURE NEAR TOE OF LONGITUDINAL WELD SEAM.



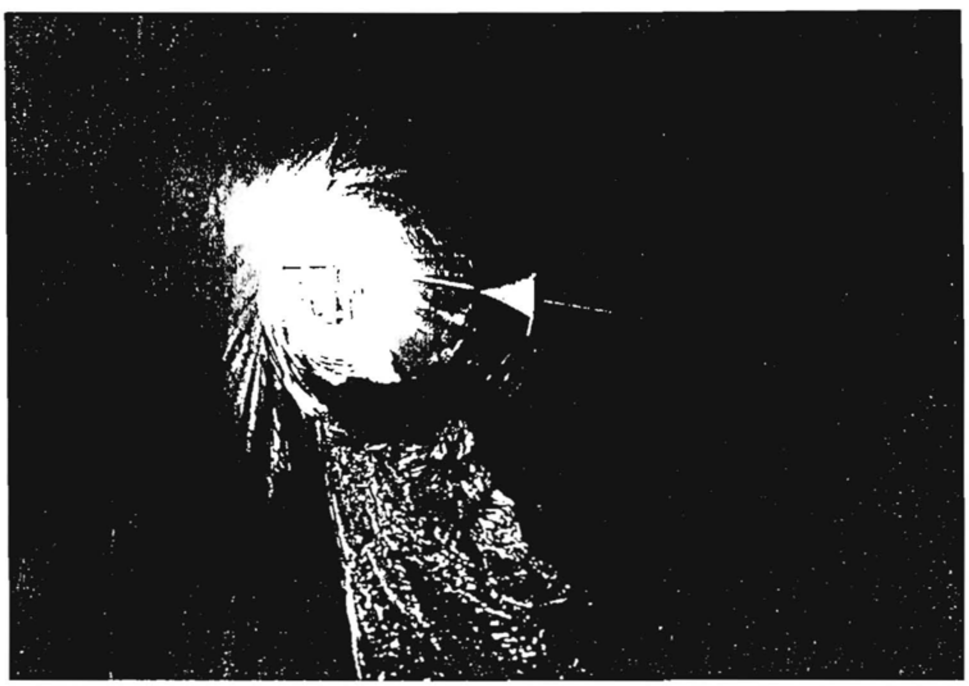
64-inch FRACTURE IN HEAT-AFFECTED ZONE NEAR TOE OF LONGITUDINAL WELD.



MP 1009.90 FAILURE.



VIEW FROM INSIDE OF THE FAILED PIPE SECTION OF THE 64-inch FRACTURE.



VIEW FROM INSIDE OF THE FAILED PIPE SECTION OF THE 64-inch FRACTURE.

APPENDIX J

LAKEHEAD PIPE LINE COMPANY, INC.
Longitudinal Seam Incidents
34" Line 3 - Gretna to Superior

	DATE	MP	Manufacturer	Weld Type	Year Inst.	Details of Leak	BBL Out	BBL Recover
1.	04-21-73	793.00	A.O. Smith	Flash	1965	1/2" crack	5	0
2.	08-22-73	794.00	A.O. Smith	Flash	1965	1" split	40	35
3.	12-04-73	831.90	A.O. Smith	Flash	1965	9' rupture	19,060	18,760
4.	07-12-74	918.00	U.S. Steel	SAW	1967	5'7" rupture	6,900	6,770
5.	07-28-74	797.00	A.O. Smith	Flash	1965	3/4" crack	30	20
6.	08-11-74	845.00	A.O. Smith	Flash	1963	1/4" crack	2	1
7.	08-23-74	925.50	U.S. Steel	SAW	1967	9'3" rupture *	10	0
8.	09-16-74	804.00	A.O. Smith	Flash	1965	1-1/2" crack	3	0
9.	06-23-75	954.70	A.O. Smith	Flash	1963	3/4" crack *	7	6
10.	08-02-75	801.00	A.O. Smith	Flash	1965	1/2" crack	1	0
11.	08-12-75	798.50	A.O. Smith	Flash	1965	1/4" crack	1	0
12.	08-13-76	840.00	A.O. Smith	Flash	1963	Pinhole crack	1	0
13.	11-01-77	881.50	A.O. Smith	Flash	1968	1" crack	3	2
14.	08-20-79	926.53	U.S. Steel	SAW	1967	64-1/2" rupture	10,690	6,757
15.	06-26-80	812.22	A.O. Smith	Flash	1963	12-1/2' rupture	2,400	2,000
16.	07-21-82	914.00	U.S. Steel	SAW	1967	52" rupture	13,000	3,800
17.	06-27-83	884.20	A.O. Smith	Flash	1968	Small crack	2	0
18.	03-06-84	882.90	A.O. Smith	Flash	1968	4 small pinholes	3	0
19.	12-03-84	881.60	A.O. Smith	Flash	1968	Small crack	5	3
20.	10-02-86	859.40	U.S. Steel	SAW	1967	1/2" crack	3	1
21.	03-26-89	860.70	U.S. Steel	SAW	1967	1-1/4" defect	300	270
22.	05-16-89	997.60	U.S. Steel	SAW	1967	1/2" crack	15	10
23.	10-09-90	795.40	A.O. Smith	Flash	1963	Pinhole	1	0
24.	03-03-91	1009.90	U.S. Steel	SAW	1967	64" rupture	40,500	39,800

* - Rupture occurred during hydrotest.

LAKEHEAD PIPE LINE COMPANY, INC.
Mainline Pipe Leak History Line 3
(Excluding Longitudinal Seam Incidents)

	DATE	MP	Manufacturer	Weld Type	Year Inst.	Details of Leak	BBL Out	BBL Recover
1.	07-14-72	845.00	A.O. Smith	Flash	1963	Mech. damage	6,000	500
2.	09-09-72	1072.80	A.O. Smith	Flash	1963	Mech. damage	700	600
3.	05-26-72	1057.00	Kaiser Steel	SAW	1962	Rock damage	30	26
4.	08-03-73	951.00	A.O. Smith	Flash	1963	Int. corrosion	15	0
5.	09-05-73	808.00	A.O. Smith	Flash	1963	Mech. damage	400	380
6.	07-14-73	1026.00	A.O. Smith	Flash	1963	Rock damage	10	5
7.	04-15-88	864.00	U.S. Steel	SAW	1967	Circ. weld	3	0
8.	04-20-89	792.00	A.O. Smith	Flash	1965	Ext. corrosion	30	20
9.	07-13-89	793.00	A.O. Smith	Flash	1965	Ext. corrosion	31,300	9000

APPENDIX K

REPORT

FINAL REPORT

INVESTIGATION OF PIPE FAILURE AT MILEPOST 1010 - LINE 3

To

LAKEHEAD PIPE LINE COMPANY, INC.

APRIL 26, 1991

Battelle

FINAL REPORT

on

INVESTIGATION OF PIPE FAILURE AT MILEPOST 1010 - LINE 3

to

LAKEHEAD PIPE LINE COMPANY, INC.

APRIL 26, 1991

by

W. A. Maxey

BATTELLE
505 King Avenue
Columbus, Ohio 43201-2693

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INVESTIGATION OF PIPE FAILURE AT MILEPOST 1010 - LINE 3

by

W. A. Maxey

INTRODUCTION

Lakehead Pipe Line Company experienced a failure on March 3, 1991, of their Line 3 at Milepost 1010 near Grand Rapids, Minnesota. The pipe is 34-inch outside diameter by 0.281-inch wall thickness Grade 5LX52 straight-seam pipe with a DSA seam weld, which was purchased from U. S. Steel Corporation in 1967. At the time of the failure, and as stated by Lakehead Pipe Line Company, the line was operating at an internal pressure between 425 and 475 psig and the estimated pipe temperature was 56 degrees F. The results of Battelle's investigation of this failure are presented herein.

SUMMARY

Two crack systems were present in this failure. The initiating crack was shallow, about 0.010-inch deep, and ran along the toe of the I.D. seam weld. It extended along most of the 64-inch length of the ductile propagating fracture. This crack was most likely caused by fatigue during shipment of the pipe. The second crack is believed to have advanced by a fatigue mechanism driven by the cyclical operation of the pipeline. It had extended to 6 inches in length along the existing I.D. crack and had grown nearly through-the-wall thickness along the central 2.5 inches of its length. Beach marks typical of fatigue cracks were observed on this crack surface even though the surface had been damaged and the detailed striations of individual fatigue cycles could not be found. A slight misalignment of the plate edges existed at the seam weld, but this misalignment was within the allowable limits according to the API 5LX specifications that were in place at

the time of purchase. It did, however, have a geometry that provided increased tensile stress at the location of the cracking.

DESCRIPTION OF THE FAILURE

General Appearance

The pipe received was 40.75-feet long and contained a girth weld on each end used to join this pipe to the adjacent pipes. The origin was 18.25 feet from the upstream end. Looking from the upstream end, the seam weld and the fracture were at the 3-o'clock position. The origin and fracture were on the lower side of the seam weld. The pipe as received had a wide black, spirally wound tape over a tar-like coating for the corrosion-protecting coating. The tape was wrinkled as is typical of similar coatings that have been subjected to minor soil movements around the pipe. Where the coating was removed, no signs of significant corrosion of the pipe surface were observed. Minimal cleaning was done when the pipe was received to locate the origin. This cleaning indicated that damage to the fracture surfaces had been done before the pipe arrived at the Battelle site, particularly to the surface away from the seam weld. Lakehead personnel believed this damage was caused by the suction line of a pump used to remove the contents of the failed pipe. Figure 1 shows the total fracture and a closer view of the origin region. The white rectangular outline indicates the samples removed for more detailed study of the origin in the laboratory.

After the origin sample was removed, it was cleaned of all tar, crude, and tape coating. Figure 2 shows the O.D. surface in a region centered about the origin. Minimal corrosive activity appeared to have occurred on the weld reinforcement but was not seen on the plate surface. The fracture deviated from the weld toe in the regions where the 45-degree slant fracture occurred. The central 2.5 inches was the final fracture of the fatigue crack initiation at the time of the rupture. Figure 3 shows the I.D. pipe surface in this same region. The crack breaking this surface remained at the toe of the weld both during initiation and propagation. The location of two metallographic sections and the SEM sample are noted on the figure. Figure 4 shows the fracture surfaces placed

O.D. surface to O.D. surface and centered about the origin. The shallow I.D. crack is slightly darker than the larger crack and runs the entire length of this photograph. The large crack was about 6-inches long where it intersected the shallow crack and about 2.5-inches long at the O.D. surface. The ratchet markings, those marks starting at the I.D. and extending through the wall, did not appear to make a distinction between the shallow crack and the larger crack, but did tend to disappear as the crack advanced through the thickness. The crack surface appeared to become smoother as the crack advanced to about mid-wall, and then the surface got coarser as the crack advanced on toward the O.D. surface. The crack surface of a fatigue crack typically becomes coarser because the increased crack size causes larger crack growth/cycle. Additionally, with pressure cycles too low or zero rest pressure, crack closure can occur, which tends to compress the fracture surfaces and the plastic zone at the crack tip. The plane of the crack was essentially straight through the wall, but the 45 degree slant propagating fracture started at the immediate edge of the crack boundary. The surface damage discussed previously is seen to be more severe on the upper fracture surface in this photograph. Beach markings can be seen faintly in the lower fracture surface and will be more apparent in the following figures.

Figures 5 through 9 show enlargements of the fracture surface on the seam weld side of the fracture. Figure 5 is from the downstream end of the origin defect and as the figure numbers increase the location progresses upstream. The pipe I.D. is down in all the figures and the figures do not join or overlap on each end. Figure 5 on the right edge has about 50 percent of the fracture nearest the O.D. pipe surface which is 45-degree slant shear fracture. The smoother darker fracture surface (believed to be a fatigue surface) at the pipe I.D. is believed to have been caused by vibrational loading stresses during the shipment of the pipe. The lighter, coarser fracture surface between the dark and the slant shear fracture is believed to have been caused by the pressure cycles normally occurring during operation of the pipeline. Figure 6 shows the fracture surface near the center of the origin. There was a very little slant fracture at the O.D. surface and the smoother fracture appeared to be about 40 percent through the thickness from the I.D. surface. Figure 7 is the opposite end of the origin defect from Figure 5 and was the fracture surface examined by the SEM and marked on Figure 3. The slant shear fracture is seen to the upper left and occupies about 40 percent of the fracture surface near the left edge of the photograph. The smoother fracture surface adjacent to the I.D. surface was variable in depth, being thickest at the right end of the photograph and narrowed considerably toward the left end. Figure 8 lies slightly upstream from Figure 7 and shows the upstream end of the origin defect. The dark, colored shallow fracture surface at the pipe I.D. surface is believed to be a fatigue fracture surface from shipping and was seen to be continuing upstream. Figure 9 shows this same shallow crack at a location along the propagating ductile fracture about 1-foot upstream from the center of the origin defect and was observed along most of the total 64 inches of fracture. The dark, coarser fracture surface in both Figures 8 and 9 are slant ductile fracture representative of propagating shear fracture. In Figures 5 through 9, so-called beach marks representing singular events during the progression of the crack front can be seen. The continuity of these beach marks was not always obvious partly because of the previously discussed damage that had occurred on the fracture surfaces.

Material Properties of Pipe

A sample was removed from the failed pipe near the upstream end for the purpose of determining material properties. A tensile coupon, chemical analysis sample, and a coupon for two transverse Charpy V-notch specimens were removed at 90 degrees from the seam weld and about 1 foot from the pipe end. Additionally, another Charpy V-notch coupon was removed for a transverse Charpy with its notch lined up with the toe of the seam weld at the I.D. surface. The data from the tensile test and the chemical analysis are listed in Table 1. As seen, all properties listed in the table meet the current API 5LX Specifications effective at the date of purchase. The charpy coupons were flattened so that at least 1/2-size specimens could be obtained. The impact energy for both the base-metal specimens and the seam-weld HAZ specimens were in the range of 31.5 to 34.0 ft-lb. The Charpy data are listed in Table 2. A small amount of brittleness was seen on all four specimens so that the shear area was between 77 and 95 percent. All specimens were impacted at a temperature of 55 F. These impact energies are approximately equivalent to 65 ft-lb for a full-size Charpy V-notch specimen and indicate a fairly high toughness material.

METALLOGRAPHIC EXAMINATION

Samples were removed from the origin region for a more detailed study using the SEM and the optical microscopes in the metallographic laboratory. The metallographic section Locations A and B and the SEM sample location are shown in Figure 3. A third metallographic section was made across the intact seam weld about 1 foot from the upstream pipe end.

Scanning Electron Microscope

The fracture surface shown in Figure 7 was examined by the SEM for striations or other positive indications of fatigue crack growth beyond those already apparent in the figure. Figure 10 is from a location near mid-wall thickness at about mid-length on Figure 7 and is typical of what was seen throughout the middle-wall thickness areas. Figure 11 is at the same axial position but within the narrow band near the I.D. surface believed to represent the fatigue due to transportation. Both show ductile fracture and show signs of damage. Figure 11 appears to have hints of striations that indicate crack growth of the order of 10^{-5} inch per cycle. Scanning was done at many locations and at different magnifications from 200X through 6,000X trying, in particular, to find depressions in which the damage was minimal. No stronger indications of striations than that shown were found during this search.

Optical Microscope

Figure 12 is the section mounted at Position A indicated on Figure 3, showing the complete seam weld and joined plate edges. This section was very near the mid-point of the origin crack. The crack initiated at the weld toe on the pipe I.D. and essentially grew straight through the wall thickness parallel to the outer edge of the HAZ.

The outer 0.02 inch was at about 45 degrees and represented the final tear through the wall thickness at this location. Figure 13 is an enlargement of the crack intersection with the I.D. surface showing the transgranular nature and the overall smoothness of the fracture. The surface intersection of the crack is seen to be right at the toe of the weld, but in some coarsened grain structure caused by the weld. Figure 14 shows two enlargements of the crack-like anomaly seen on Figure 13 at the weld toe near the fracture. There appeared to be some plastic straining of this material at the weld surface near this opening and some corrosion products in the opening, but no cracks were found at the deepest depth of the opening. A single crack, Figure 15, was found near mid wall on the plate side of this fracture. This secondary crack does not have any of the features of environmental cracking and is probably a local fatigue crack initiated from the stress concentrations effect of the opening. The main fatigue crack probably grew past it at a faster growth rate and the secondary crack was arrested at that time. This crack was transgranular and extended at a 45-degree angle away from the weld direction and from the end of a relatively blunt opening intersected by the main advancing crack. Note the inclusions in this area, two of which are about 1/2 mil in size.

Figure 16 is the section mounted at Position B indicated on Figure 3 showing the complete seam weld and joined plate edges. This section was near the end of the origin crack and shows only a short crack straight through the wall with most of the fracture being at 45 degrees to the plate surface. The necking typical of propagating shear fracture is seen at the O.D. intersection of the fracture. The I.D. fracture was also at the toe of the seam weld, was smooth, and propagated parallel to the edge of the HAZ. Figure 17 is an enlargement of the weld toe and the weld side of the origin crack. The origin crack is seen to be smooth and transgranular typical of fatigue crack growth. There are two blunt or corroded crack-like openings next to the origin crack, and there may have been a similar but larger opening that acted as a crack starter for this origin. The origin crack surfaces, however, appeared to be smoother than would be expected if blunt openings such as these were the starter crack.

Figure 18 shows a section about 1 foot from the upstream end of the failure pipe across an intact section of the seam weld. Two magnifications are shown, one to compare with other fractured segments discussed earlier and the second to illustrate the slight offset of the plate edges at the seam weld. The plate surfaces in the photograph have been extended by lines into the weld beads to the midpoint of the weld. Measurements indicated an offset of about 0.027 inch. This amount of offset is allowed by API 5LX pipe specifications, which allows up to 1/16 inch (0.063 inch) for this diameter and wall thickness combination. The effect of this offset, nevertheless, would be to produce a higher tensile stress at the left I.D. weld toe, which was the location of the fracture in this pipe. The tendency under tensile loading is for the misaligned weld segment to rotate towards alignment, and when it does the I.D. toe notch is loaded additionally in tension. Hardness readings were taken on this section at mid-wall and near the I.D. surface. The readings were taken using a Knoop microhardness tester with a 500-gram penetration load. The maximum hardness in any region was at 212 Knoop Hardness Number, which is equivalent to Rockwell B of 92. These data are shown in Tables 3 and 4.

DISCUSSION AND CONCLUSIONS

A long, shallow surface crack was identified extending from the I.D. notch produced at the toe of the seam weld. This crack was nearly the total length of the propagating fracture, at least 64-inches long and possibly longer as it still existed at the arrest point on the one end. The crack is believed to have initiated and propagated to an average depth of about 10 mils due to the static and dynamic stresses produced during the shipment of the pipe. The mode of propagation was transgranular, which is typical of a fatigue mechanism. Although averaging 10 mils, the crack did vary in depth, and near the center of the failure origin it was about three times this depth (see Figures 6 and 7). This deeper crack region also presumably was formed by transportation stresses.

The fracture origin crack appeared to have grown from the deeper transportation-grown surface crack described above by a fatigue mechanism driven by the cyclical operation of the pipeline. This crack grew to nearly through-the-wall thickness in depth over a length of 2.5 inches at the O.D. surface and extended in length to about 6 inches at the I.D. surface. There was no evidence that corrosion was a factor in the failure.

TABLE 1. TRANSVERSE TENSILE PROPERTIES AND CHEMICAL ANALYSIS

Tensile Data

Location	Yield Strength 0.5 Percent Strain, ksi	Ultimate Tensile Strength, ksi	Elongation, percent
Failed Pipe	58.0	79.0	30.5
1990 API Specification, 5LX52	52.0	66.0	24.0

Chemical Analysis (percent by weight)

Element	Failed Pipe	1990 API Specification Maximum Value, Product Analysis
Carbon	0.25	0.32
Manganese	1.10	1.35
Phosphorus	0.009	0.05
Sulfur	0.018	0.06
Silicon	0.036	
Copper	0.022	
Tin	0.001	
Nickel	0.043	
Chrome	0.030	
Molybdenum	0.014	
Aluminum	0.000	
Titanium	0.000	
Cobalt	0.004	
Vanadium	0.000	
Niobium	0.000	

TABLE 2. CHARPY V-NOTCH DATA[a]

Specimen	Test Temperature, F	Impact Energy, ft-lbs	Shear Area, percent
A	55	32	80
B	55	31.5	77
CW[b]	55	32	80
DW[b]	55	34	95

(a) Transverse specimen; 1/2 size.
(b) Notch in line with top of ID seam weld, fracture side.

TABLE 3. HARDNESS DATA

Date 3-22-91

Recorder Thompson

HARDNESS DATA

Project N0742-7001

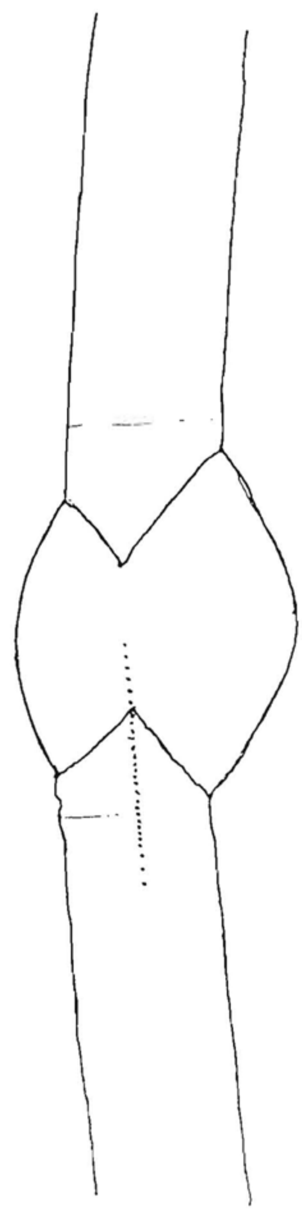
Machine No. 923-25

Knoop Hardness Readings

Penetrator 500 Gram Load

Observations On

HEAT No.	SPECIMEN L H (Mid-Wall) No.	Material	Condition
		203	
20 mils	apart	205	Base Metal
		199	
		187	
		186	
		185	
		185	
		189	
		182	
		189	
		189	
		189	
10 mils	apart	190	
		187	
		190	
		192	
		198	
		204	
		204	
		202	
		191	
		175	
		182	
20 mils	apart	178	Weld Metal
		182	
		177	
		169	



REMARKS

TABLE 4. HARDNESS DATA

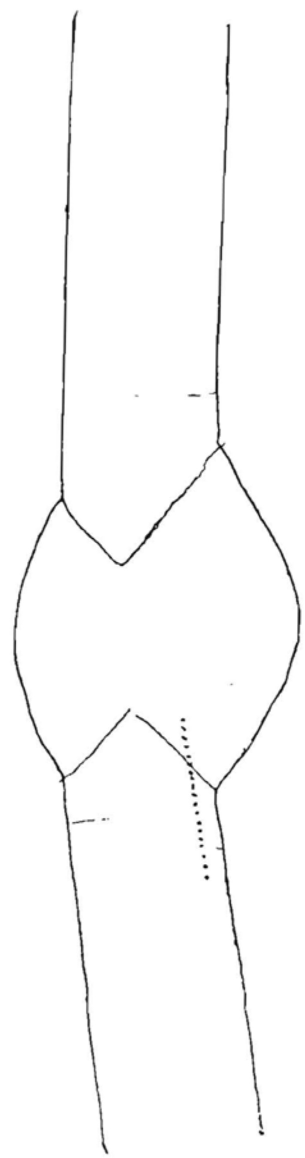
HARDNESS DATA

Date 3-22-91
Recorder Thompson

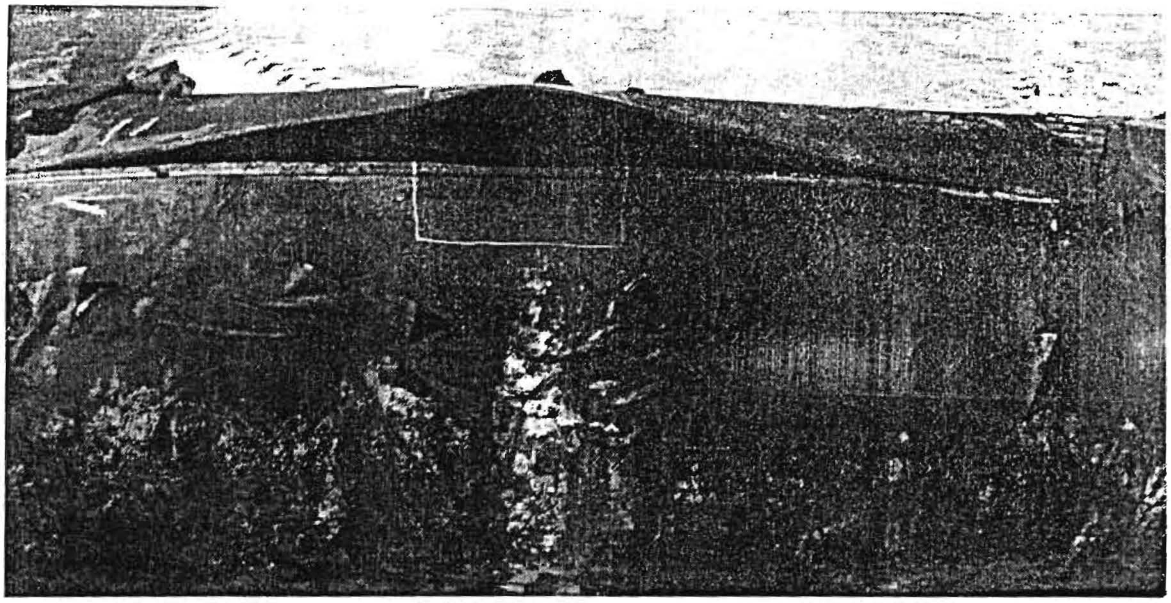
Project N0742-7001
Machine No. 923-25

Knoop Hardness Readings
Penetrator 500 Grams Kg. Load
Observations On

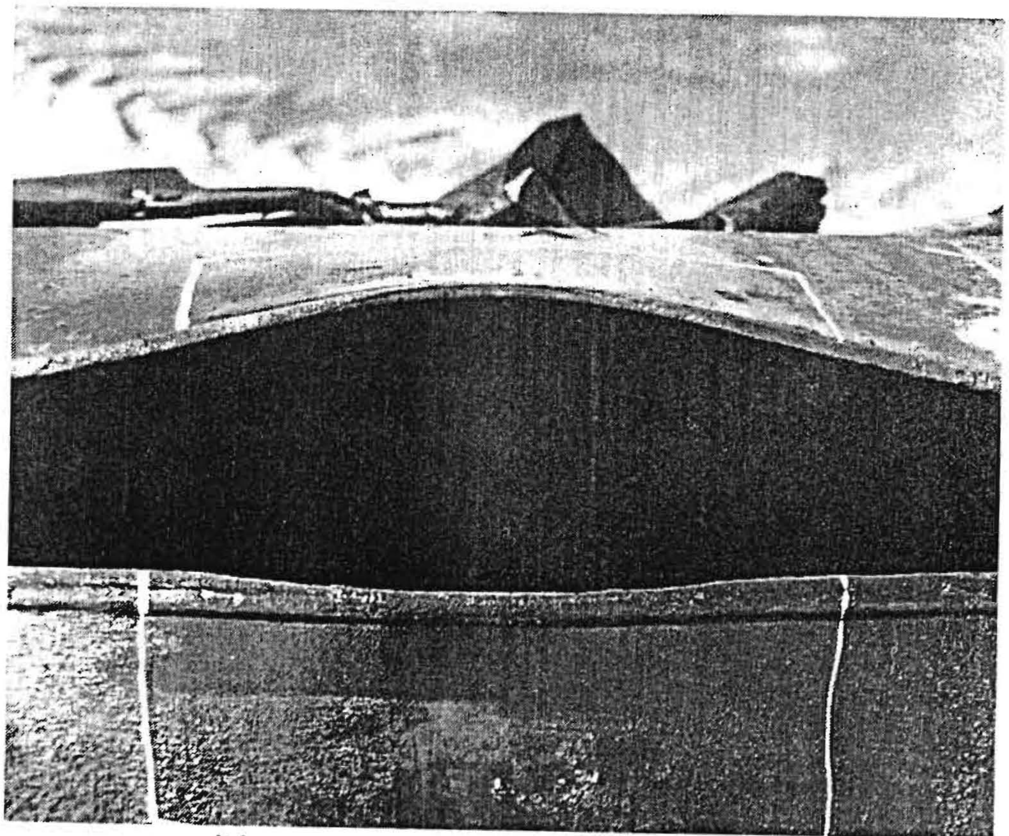
HEAT No.	SPECIMEN LH (I.D.) No.	Material	Condition
		209	
		205	Base Metal
20 mils	apart	198	
		204	
		204	
		212	
		204	
		205	
		199	
mils	apart	208	
		194	
		206	
		206	
		181	
		190	
20 mils	apart	191	Weld Metal
		194	
		186	



REMARKS

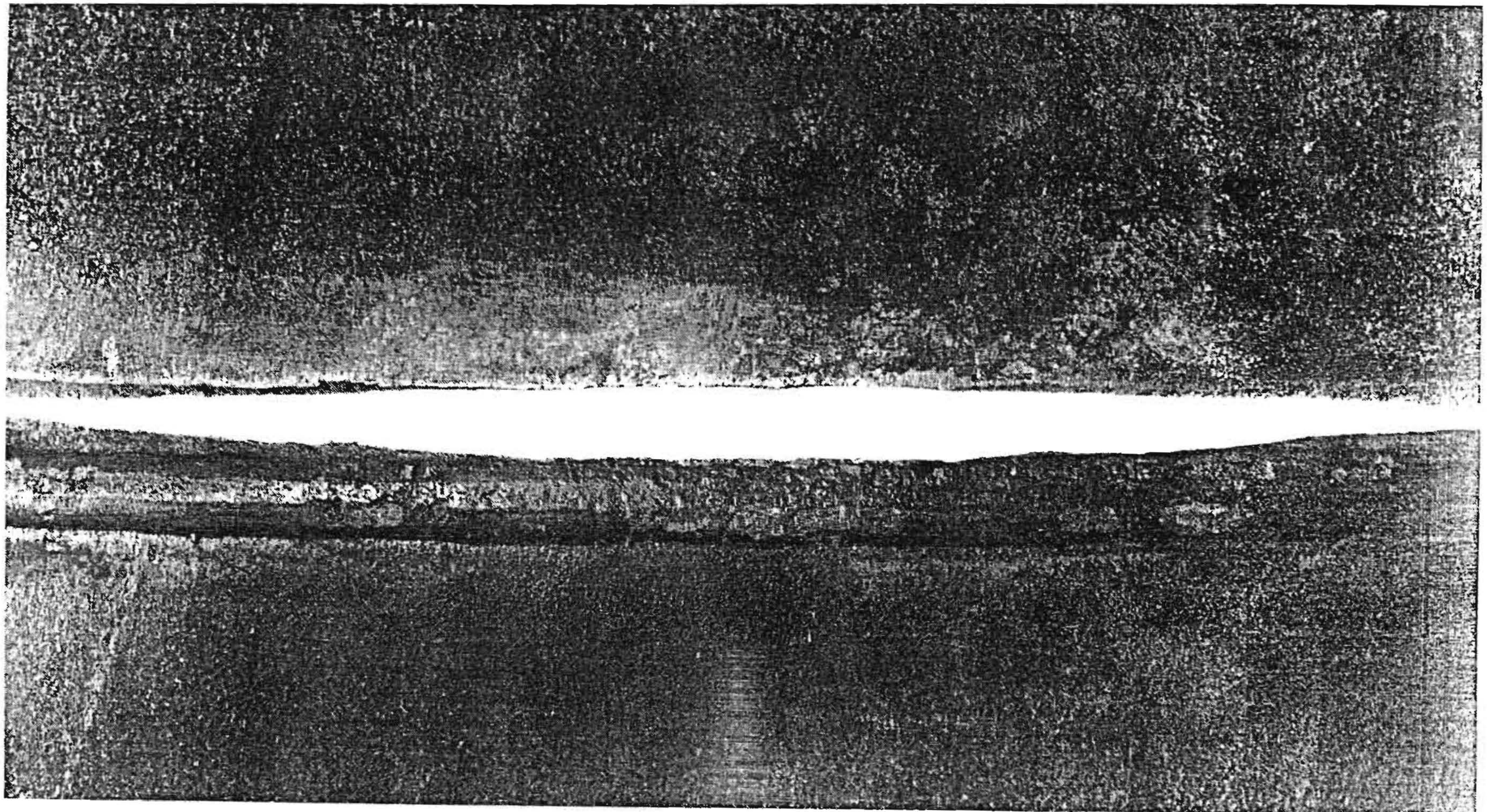


(a) Total fracture



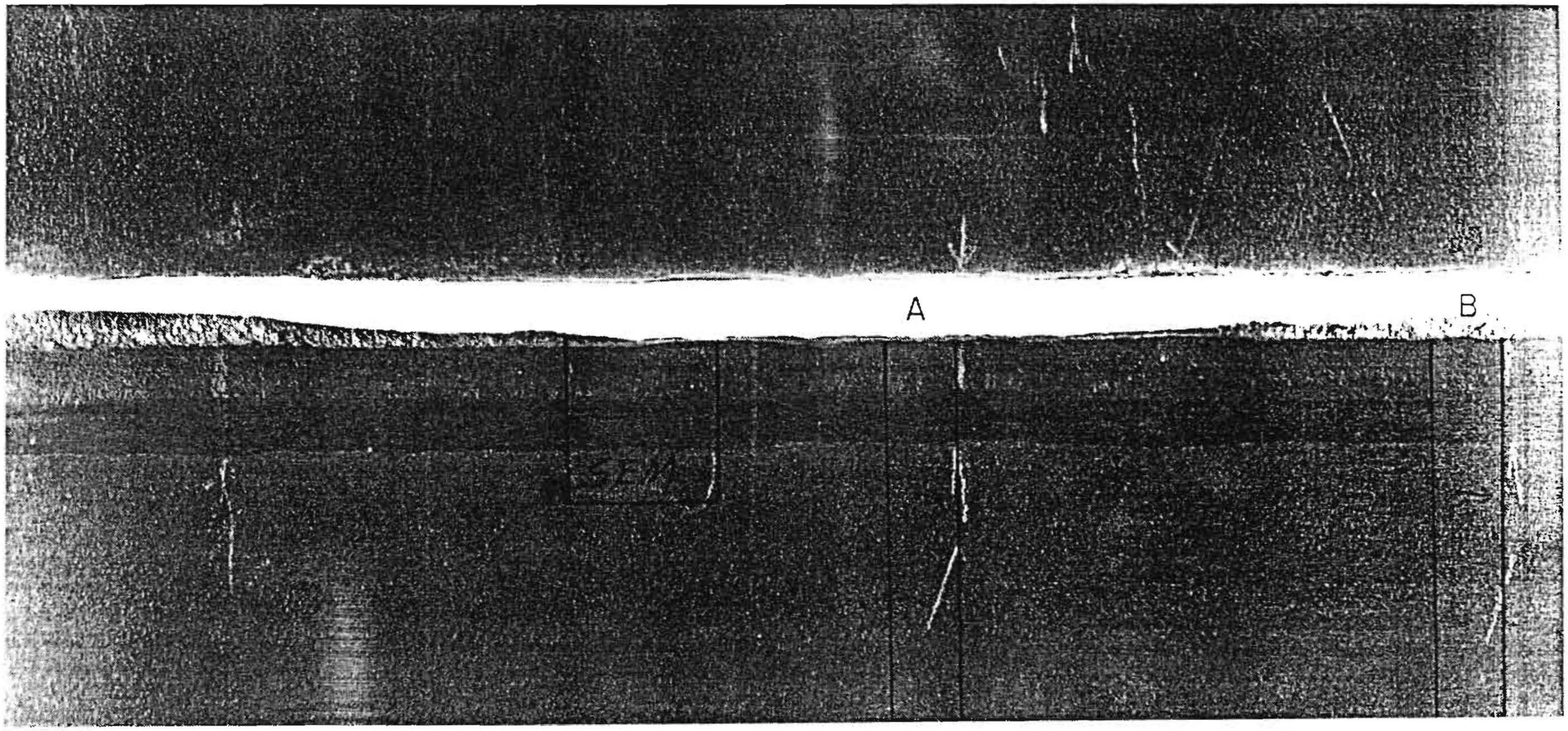
(b) Close-up view of origin region

FIGURE 1. VIEW OF FRACTURE BEFORE REMOVAL OF ORIGIN SAMPLE



1X As cleaned 40333

FIGURE 2. O.D. SURFACE AT ORIGIN

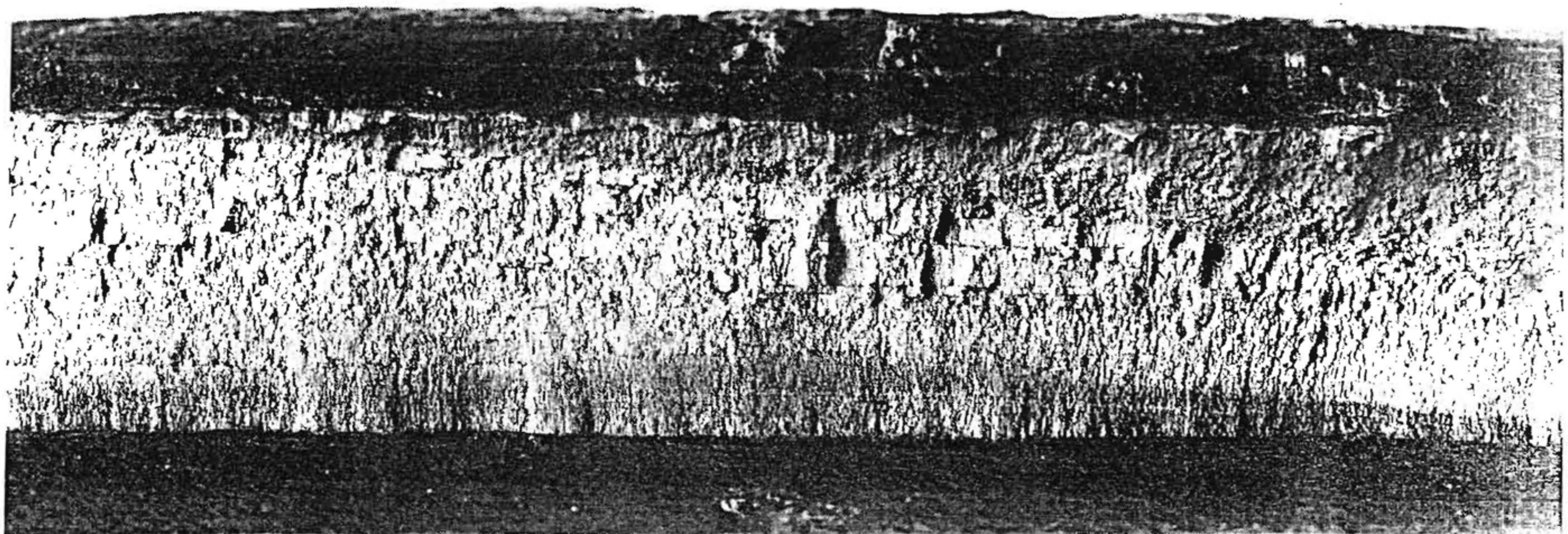


1X As cleaned 40332

FIGURE 3. I.D. SURFACE AT ORIGIN

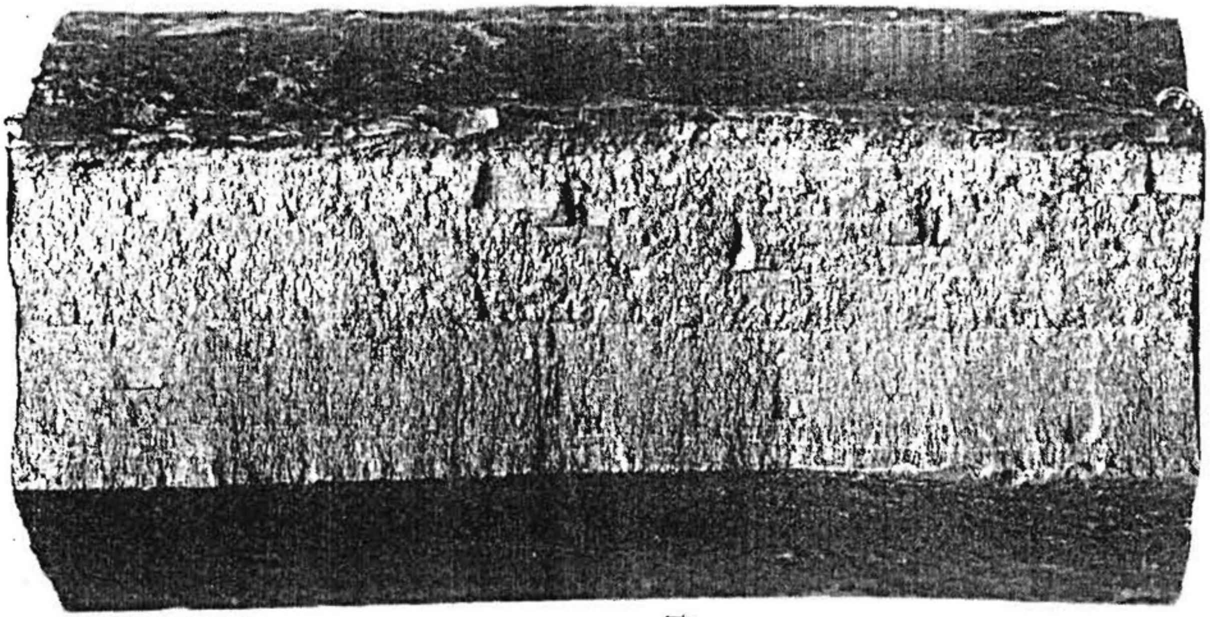
1X As cleaned 40330

FIGURE 4. FRACTURE SURFACES AT ORIGIN



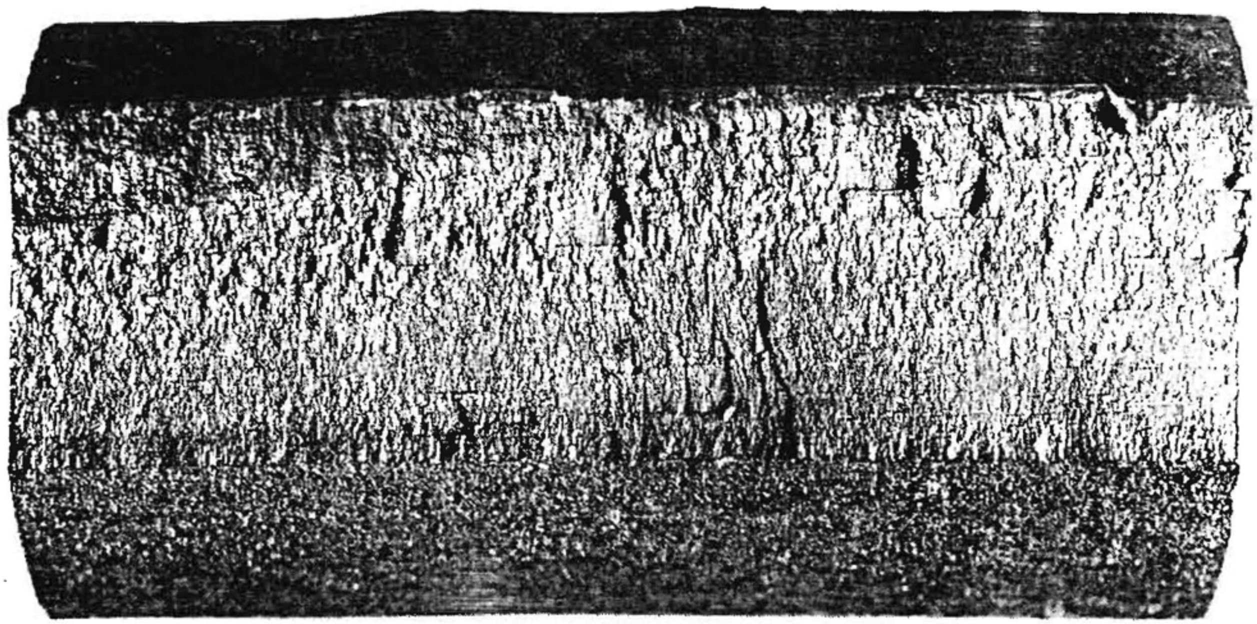
7X As cleaned 40473

FIGURE 5. ORIGIN FRACTURE SURFACE DOWNSTREAM END



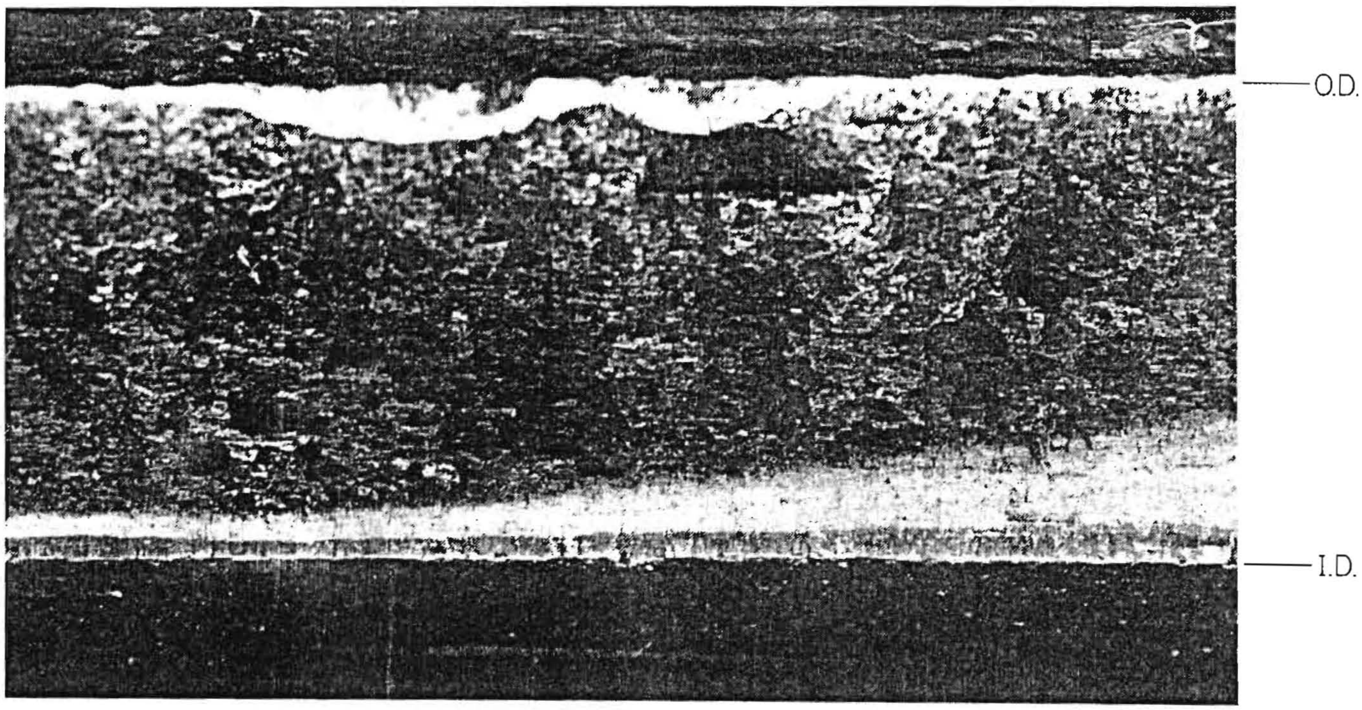
7X As cleaned 40472

FIGURE 6. FRACTURE SURFACE NEAR CENTER OF ORIGIN DEFECT



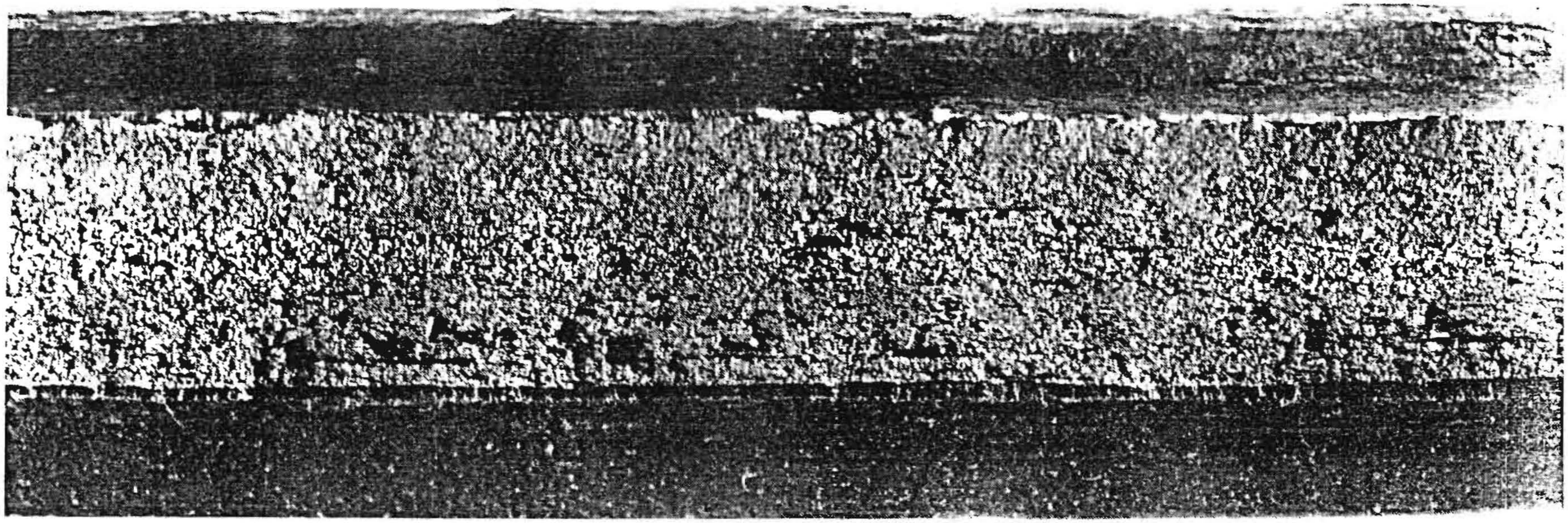
7X As cleaned 40527

FIGURE 7. FRACTURE SURFACES NEAR UPSTREAM END OF ORIGIN DEFECT



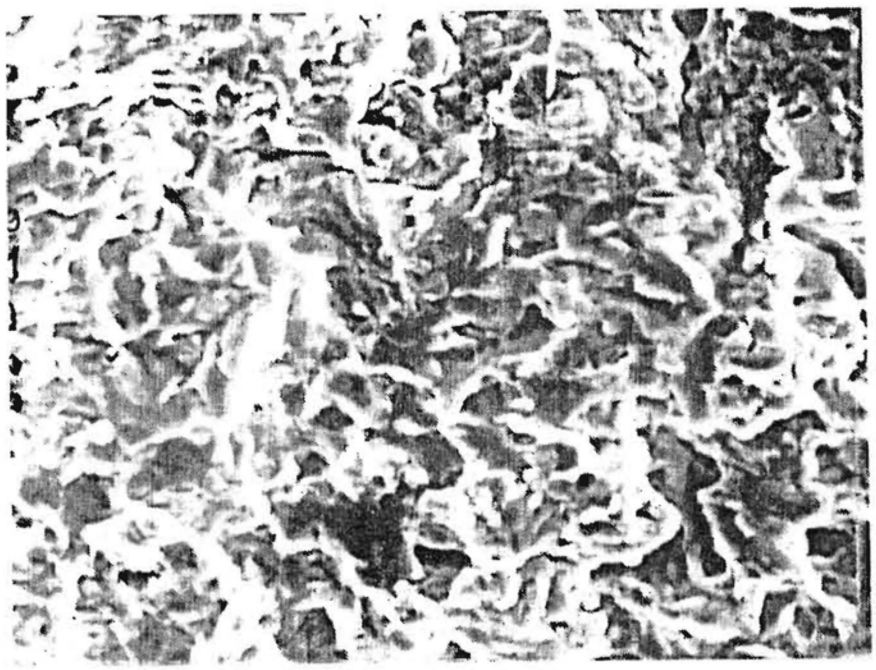
10X As cleaned 40329

FIGURE 8. FRACTURE SURFACE AT FAR UPSTREAM END OF ORIGIN DEFECT



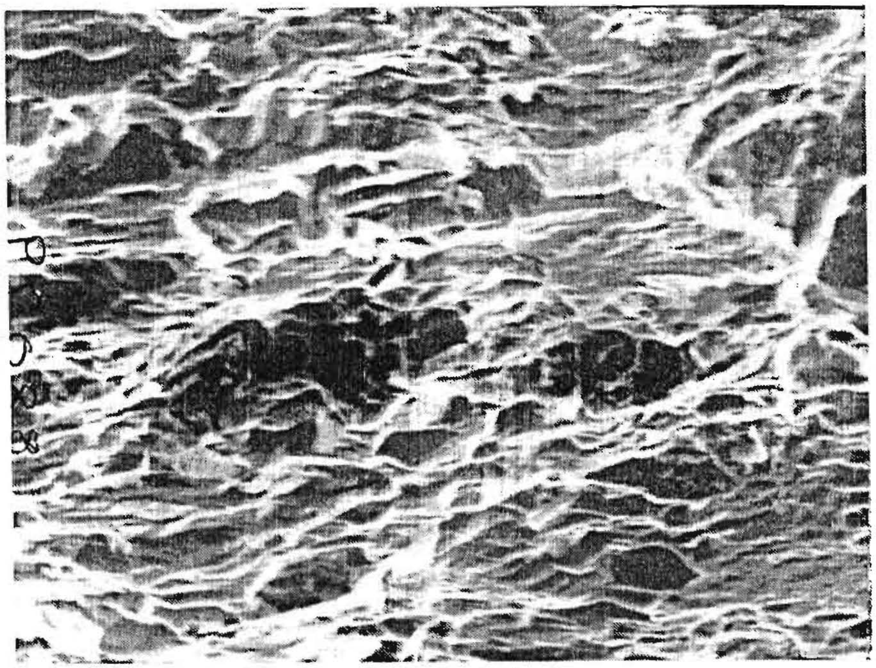
7X As cleaned 40474

FIGURE 9. FRACTURE SURFACE ABOUT 1-FOOT UPSTREAM FROM ORIGIN



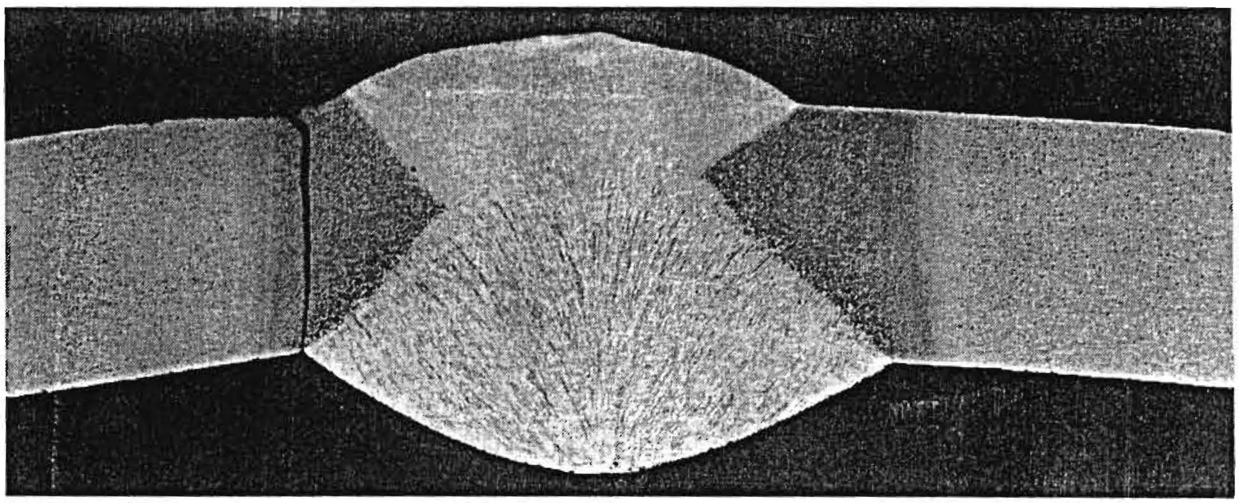
1500X Electropolished surface 88058

FIGURE 10. SEM VIEW OF FRACTURE SURFACE NEAR MID-WALL THICKNESS AT ORIGIN



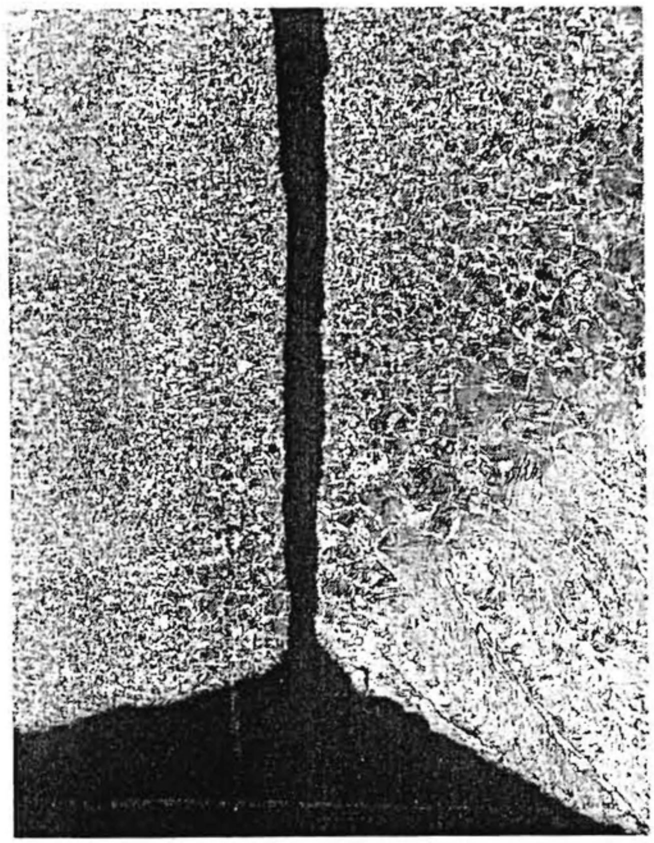
1500X Electropolished Surface 88059

FIGURE 11. SEM VIEW OF FRACTURE NEAR I.D. AT ORIGIN



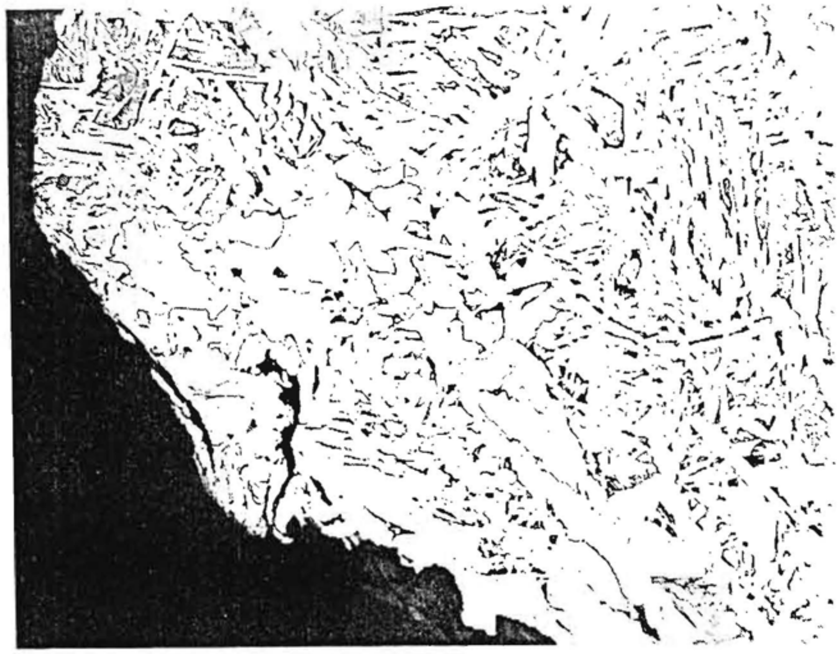
5X 5% nital 40327

FIGURE 12. SECTION AT LOCATION A NEAR THE MID POINT OF ORIGIN CRACK



50X 2% nital 40319

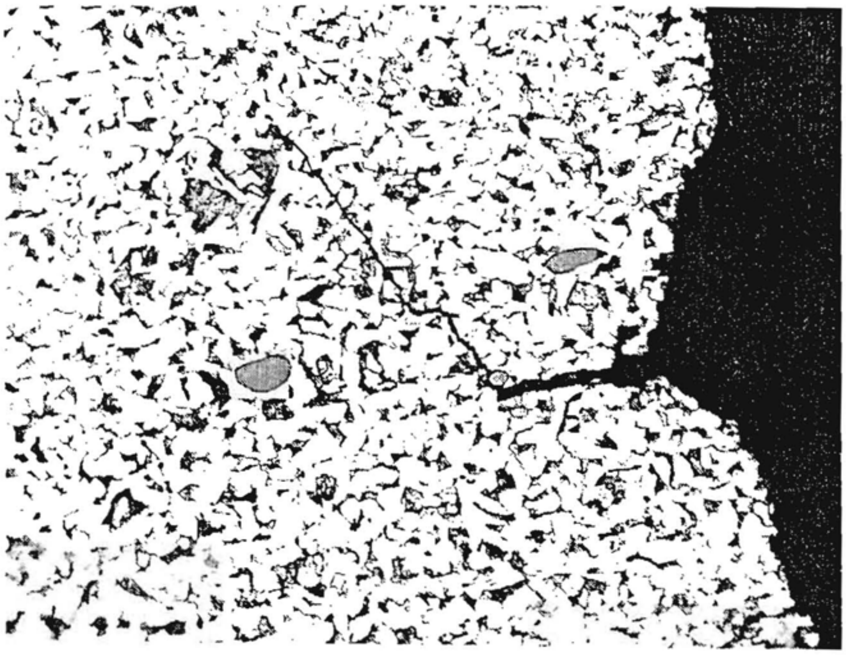
FIGURE 13. ENLARGEMENT OF CRACK AT WELD TOE OF SECTION A



250X 2% nital 40320

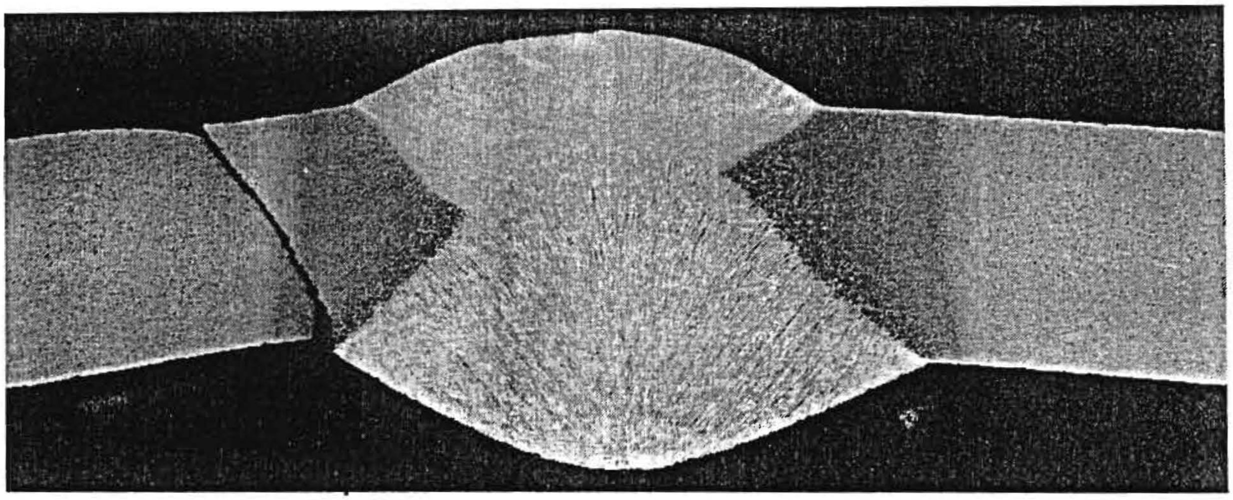
500X 2% nital 40321

FIGURE 14. WELD TOE REGION AT I.D. SURFACE ADJACENT TO ORIGIN CRACK AT SECTION A



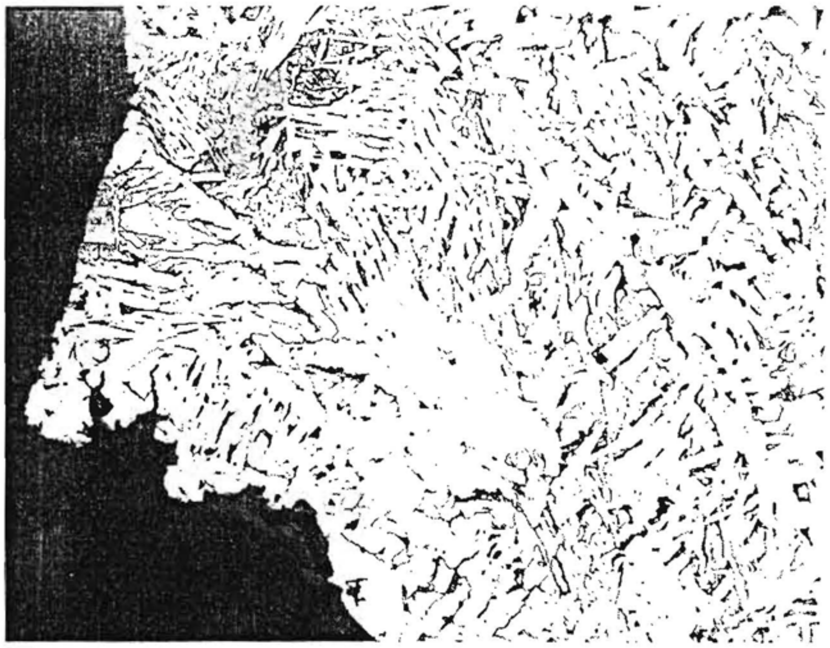
500X 2% nital 40322

FIGURE 15. CRACK NEAR MID WALL AT SECTION A

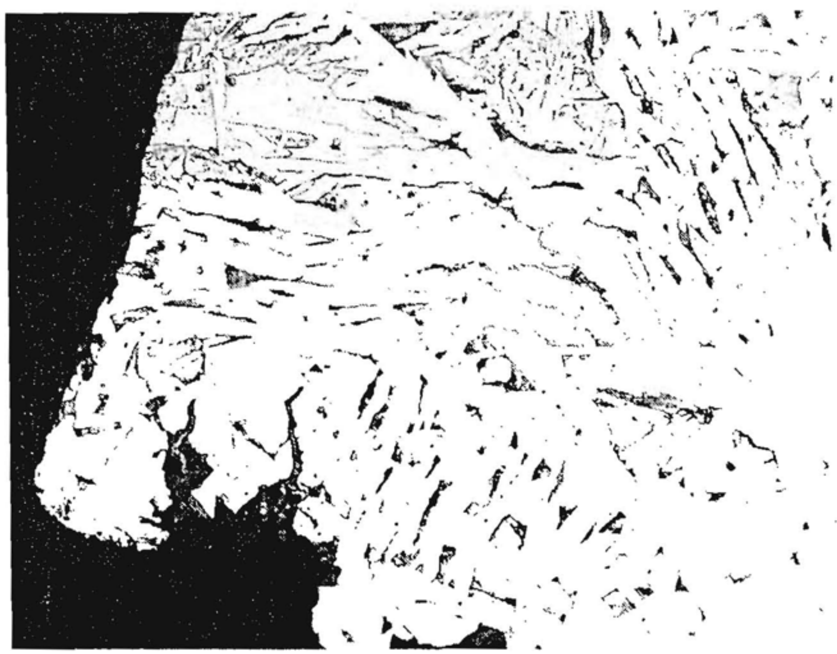


5X 2% nital 40328

FIGURE 16. SECTION AT LOCATION B NEAR THE END OF THE ORIGIN CRACK

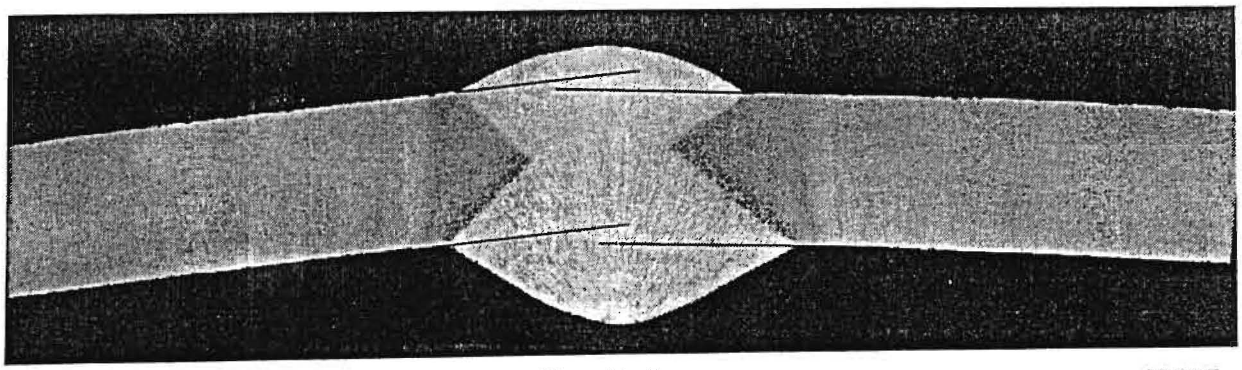


250X 2% Nital 40324



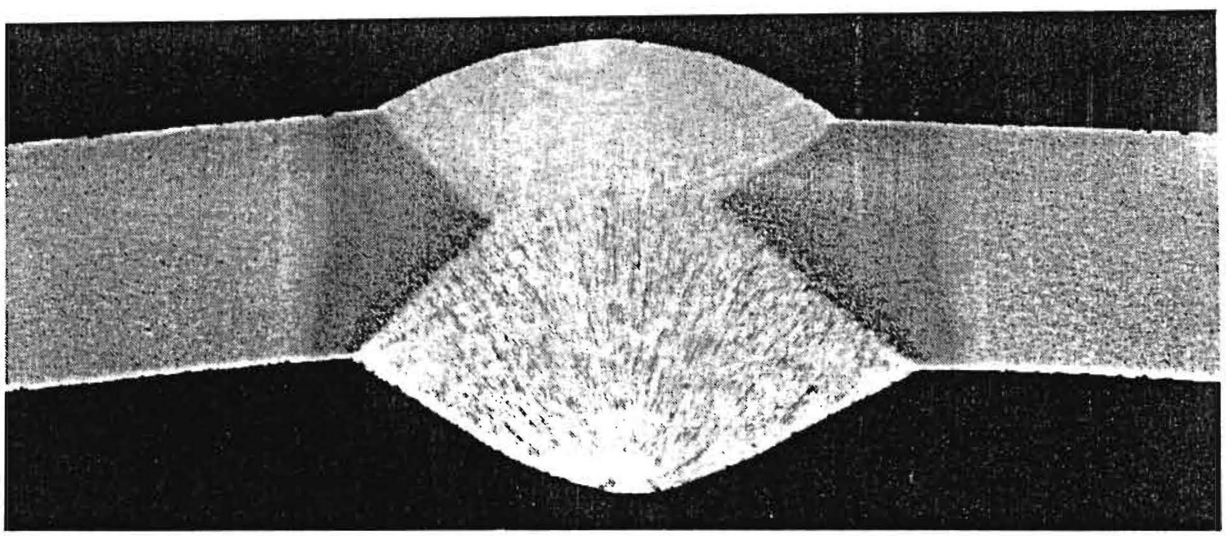
500X 2% Nital 40323

FIGURE 17. WELD TOE REGION AT I.D. SURFACE AT SECTION LOCATION B



3X 5% nital 40325

(a) Section indicating plate edge offset



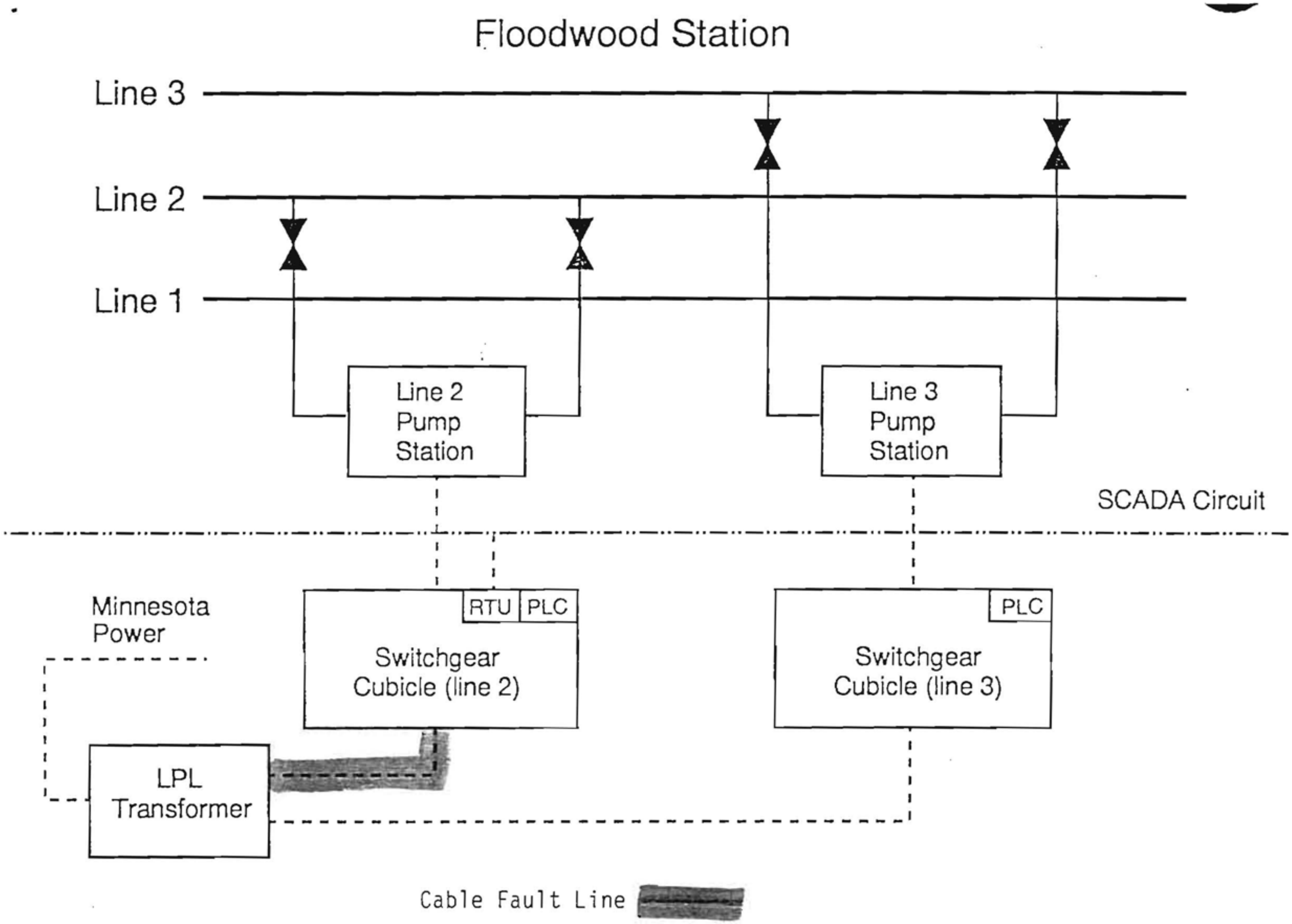
5X 5% nital 40326

(b) Comparative section; magnification same as fractured section photographs

FIGURE 18. SECTION ACROSS INTACT WELD NEAR UPSTREAM END OF FAILURE PIPE

APPENDIX L

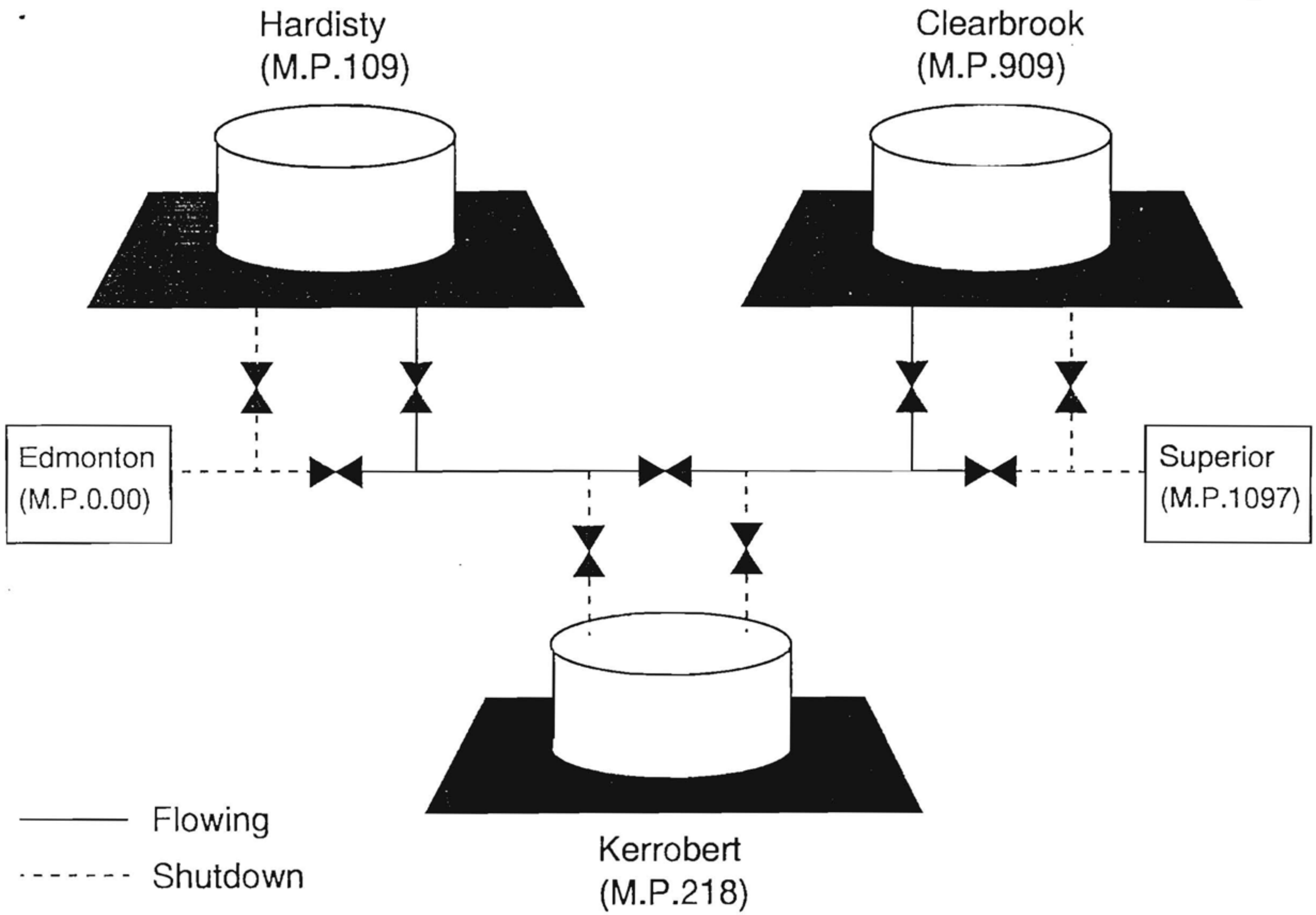
SIMPLIFIED PIPING & ONE LINE SCHEMATIC



APPENDIX M

LINE 3 FLOW SCHEMATIC

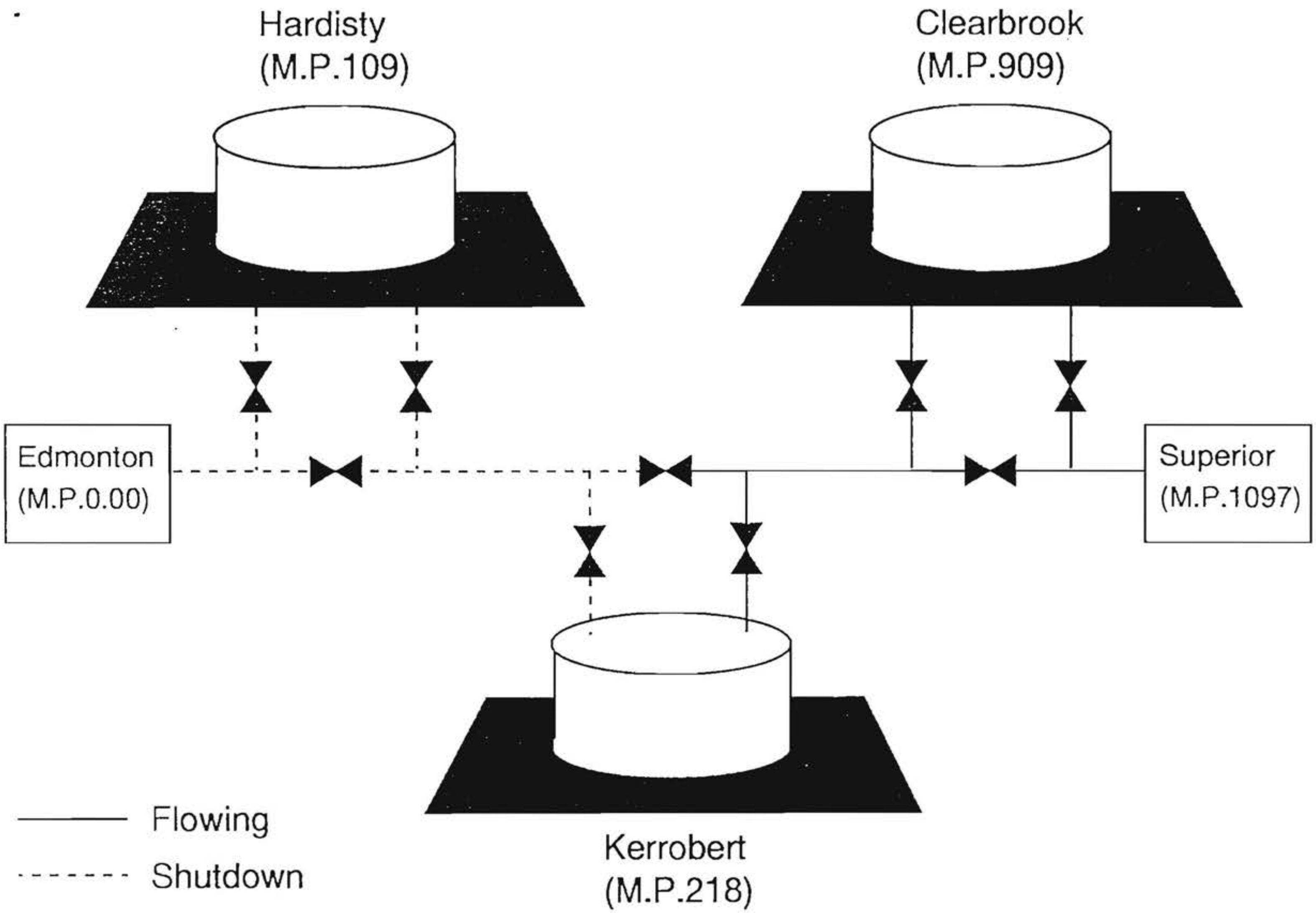
520 MST, March 3, 1991



APPENDIX N

LINE 3 FLOW SCHEMATIC

1006 MST, March 3, 1991



APPENDIX O

LINE 3 FLOW SCHEMATIC

1120 MST, March 3, 1991