PIPELINE OCCURRENCE REPORT
P96H0008

CRUDE OIL PIPELINE RUPTURE

INTERPROVINCIAL PIPE LINE INC.
LINE 3, MILE POST 506.6830
NEAR GLENAVON, SASKATCHEWAN
27 FEBRUARY 1996

Transportation Safety Board of Canada

Bureau de la scurit des transports du Canada

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Synopsis

At 0619 mountain standard time, on 27 February 1996, a rupture occurred on the Interprovincial Pipe Line Inc. 864-millimetre outside diameter pipeline designated as Line 3, at Mile Post 506.6830 near Glenavon, Saskatchewan. Approximately 800 cubic metres (m^3) (5,000 barrels) of heavy crude oil was released and collected in a low-lying area near the site. Approximately 600 m^3 (3,800 barrels) of heavy crude oil was recovered.

The Board determined that the rupture was caused by excessive narrow, axial, external corrosion located adjacent and running parallel to the longitudinal seam weld of the pipe, which was assisted by low-pH stress corrosion cracking and was not identified through the company's ongoing pipeline integrity program called the Susceptibility Investigation Action Plan.

Ce rapport est également disponible en français.

1.0 Factual Information

1.1 The Accident

On 27 February 1996, at 0619, the Interprovincial Pipe Line Inc. (IPL) 864-millimetre (mm) outside diameter (nominal pipe size (NPS) 34 inches) main crude oil pipeline, designated as Line 3, suddenly experienced a simultaneous loss of operating pressure and increase in crude oil flow rates at both the Glenavon pump station, Mile Post (MP) 504.722, and at the Langbank pump station, MP 543.839, located near the towns of Glenavon and Langbank, Saskatchewan. The Control Centre Operator (CCO), located in Edmonton, Alberta, remotely operates the Glenavon and Langbank pump stations 24 hours a day, 7 days a week. These two pump stations are normally unmanned.

At 0620, from the control console in the Edmonton Control Centre (ECC), the CCO initiated an emergency pipeline shutdown of Line 3 for all the IPL pump stations from Hardisty, Alberta (MP 109.019), to its associated facilities located at Superior, Wisconsin, U.S. (MP 1097.372). The net effect of the CCO's command would stop the movement of crude oil by shutting down pipeline facilities on Line 3.

At 0624, the ECC notified the Royal Canadian Mounted Police (RCMP) of the suspected leak in the Glenavon-to-Langbank area of the pipeline system.

At 0626, the CCO issued close commands to the remotely operated sectionalizing valves located at Odessa, Saskatchewan (MP 473.479), and Langbank. At the same time, close commands were issued to the remotely operated sectionalizing valves located at MP 504.860 and MP 543.980. At 0629, all these valves were confirmed closed by IPL's Supervisory Control and Data Acquisition (SCADA) system.

At 0630, Line 3 was confirmed closed by the SCADA system.

At 0638, IPL's Central Region management was notified of the suspected leak.

At 0640, IPL's Pipeline Maintenance Supervisor was notified of the occurrence, and deployed verifiers and containment personnel from IPL's Regina and Glenavon pump stations.

At 0845, company employees located the occurrence site at MP 506.6830, approximately 3 km downstream of the Glenavon pump station. They then proceeded to secure the occurrence site. The closest sectionalizing valve upstream of the rupture site is located at the Glenavon pump station, which had been remotely closed earlier by the CCO, thus restricting the amount of crude oil that would drain down. The nearest sectionalizing valve downstream of the site was a manually operated valve located at MP 531.0, which had not been closed. Due to the elevation profile of the pipeline at this valve location, IPL decided that this manual valve did not need to be

[1] All times are mountain standard time (Coordinated Universal Time (UTC) minus seven hours) unless otherwise stated.

closed to prevent an unnecessary drain-down of crude oil into the occurrence site. The next closest sectionalizing valve downstream of the rupture site is located at the Langbank pump station, and had been remotely closed earlier by the CCO.

At approximately the same time, plans were put in motion by the Pipeline Maintenance Supervisor for IPL's pipeline maintenance crew to:

i) limit the scope of contamination of the spilt crude oil;
ii) begin the task of containing and collecting the spilt crude oil;
iii) begin the task of storing the spilt crude oil and contaminated water at the occurrence site to portable storage tanks for future removal from the area;
iv) commence the mobilization of the repair team and associated repair equipment to the site;
v) repair the ruptured pipeline system and commence initial clean-up; and
vi) return the pipeline system to normal operating conditions in an expeditious manner.

At 0227, on 28 February 1996, approximately 20 hours after the first indication of an occurrence, Line 3 was returned to normal service.

1.2 Injuries

There were no injuries as a result of this occurrence.

1.3 Damage to Equipment - Product Lost

Damage to Line 3 consisted of 1.760 m (approximately 5.8 feet) of ruptured pipe which had split open in the longitudinal direction, in proximity to the longitudinal seam weld.

An estimated 800 m^3 (5,000 barrels) of heavy crude oil was spilt and approximately 600 m^3 (3,800 barrels) was recovered. The remaining released crude oil contaminated the soil, and the snow and ice surrounding the occurrence site had to be moved to a disposal site. A ground survey indicated that approximately 0.578 hectares (1.4 acres) of low-lying terrain came in contact with the released crude oil. Since the water and soil at the occurrence site were frozen and the initial clean-up was completed before the spring thaw, no long-term impact on fish, livestock or wildlife habitat was anticipated by IPL.

Sections of pipe were removed upstream and downstream of the occurrence site. The repairs to Line 3 were completed using pipe of a length of 11.565 m (about 38 feet) welded in place, using Weld-Plus couplings. The pipe was sand-blasted then coated with a spray-applied polyurethane.

1.4 Weather

On the morning of the rupture, the skies were clear, the temperature was minus 23 degrees Celsius, and the winds were out of the north-west at 20 to 25 km/h.

1.5 Particulars of the Pipeline System

At the occurrence site, IPL has five parallel lines of pipe: one designated as Line 1 with a nominal outside diameter of 508 mm (NPS 20 inches) used principally to transport natural gas liquids and refined petroleum products; a second designated as Line 2 with a nominal outside diameter of 610 mm (NPS 24 inches) used principally to transport light and medium crude oils; a third designated as Line 3 with a nominal outside diameter of 864 mm (NPS 34 inches) used principally to transport light, medium and heavy crude oils; a fourth designated as Line 13 with a nominal outside diameter of 406.4 mm (NPS 16 inches) used principally to transport light crude oil; and a fifth designated as Line 1A which had been abandoned in place. The five pipelines are buried in a dark brown, clay, loam textured soil, with some small stones or pebbles and coarse sand indicative of a fine-textured glacial till.

Immediately downstream of and adjacent to the occurrence site, the IPL pipeline system is crossed by the Trans Gas Ltd. natural gas pipeline. Approximately 0.058 hectares (0.14 acres) of the Trans Gas Ltd. right-of-way was covered in crude oil from this occurrence.

The nominal wall thickness of Line 3 is 7.14 mm (0.28 inches). The pipe was manufactured in 1968 by the Stelco Pipe Mill in Camrose, Alberta, with a double-submerged arc-welded (DSAW) longitudinal seam weld and a pipe grade of steel of 359 megapascals (MPa) (American Petroleum Institute (API) 5LX pipe grade X-52). The section of Line 3 that ruptured was constructed in 1968 as Loop 32 and was externally coated at that time with one layer of self-adhesive polyethylene tape.

The section which ruptured had been hydrostatically tested in 1968 to a maximum test pressure of 6,189 kilopascals (kPa) (about 815 pounds per square inch gauge (psig)), which corresponds to approximately 95 per cent of the specified minimum yield strength (SMYS). The National Energy Board (NEB) had issued a "Leave to Open" to the IPL at a maximum allowable operating pressure (MAOP) of 4,945 kPa (about 650 psig) which corresponds to about 76 per cent of the SMYS. Since its original construction and until the time of this occurrence, this section of Line 3 had not been hydrostatically re-tested.

Between the Glenavon and Langbank pump stations, which includes the present occurrence site, there has been a history of three ruptures and one previous leak in this section of Line 3 and of prior repairs. Starting in 1981 until the end of 1995, IPL had excavated at 61 locations on this section to examine the exterior condition of the pipeline. As a result of these excavations, IPL had performed a variety of repairs. The type of repairs performed ranged from re-coating the exterior surface to installing structural reinforcing sleeves on joints of pipe that had been found to be substandard due to external corrosion similar to the type of external corrosion found at the occurrence site.

The rupture of Line 3 did not cause any damage to Lines 1, 2, or 13. Before the occurrence, the last IPL aerial patrol of the right-of-way had been carried out on 20 February 1996 over this portion of the pipeline system; no concerns had been noted by the pilot of the plane.

1.6 Commodity Pipeline Operations

The IPL ECC relies on selected telemetric data from pump and meter stations coming from IPL's SCADA telemetry network across the pipeline system to determine the optimum operating scenarios for moving contracted quantities of Western Canada hydrocarbons. These hydrocarbons include:

i) natural gas liquids containing a mixture of products including propane and butane;
ii) refined petroleum products such as gasoline, jet fuel, diesel fuel and heating fuel;
iii) synthetic crude oils;
iv) condensate liquids; and
v) light, medium and heavy crude oils.

The IPL pipeline system is subdivided into regional areas, each under the direct control of the ECC. The ECC responsibilities are assigned to a CCO for each of its three main pipelines in Western Canada (i.e. Lines 1, 2, and 3). For pipeline operations, Line 4 forms part of the spectrum of responsibility of the Line 3 CCO. These three CCOs report directly to one senior CCO.

On the day of the occurrence and before the occurrence, no unusual situations were being managed by the CCO for Line 3.

A review of the telemetric data for the day in question shows that, before the break, IPL's pipeline was flowing at approximately 4,755 m^3 per hour (29,900 barrels per hour) of a heavy crude oil referred to as "Gibsons Blend." All functions had been normal for the previous 24 hours and no abnormalities in operating conditions were identified from this review.

1.7 Cathodic Protection on Line 3

Cathodic protection (CP) is provided by means of an impressed current system on each of the four operating pipelines. The CP distribution system is located in the yard at the Glenavon pump station.

In order to determine the effectiveness of the CP system and to ensure that the existing minimum industrial norm of 850 millivolts (mV) "off" cathodic potential and 100 mV shift potential were met, IPL's field staff and contract staff performed pipe-to-soil potential surveys (annual surveys) throughout the life of the system. The annual survey records for the period between 1988 and 1994 showed that the potentials at the rupture site consistently exceeded the minimum industrial norm.

1.8 Analysis of the Soil and Water at the Occurrence Site

When this section of the IPL system was built in 1968, the pipeline was buried in the soil with a depth of cover to the top of the pipe of approximately 0.9 m (3 feet). The IPL right-of-way terrain from Glenavon to Langbank has been classified as farm land.

The analysis of the soil and groundwater found at the occurrence site revealed the following characteristics:

i) a sulphate rich environment which is moderately saline and moderately calcareous;
ii) the dominant salts are gypsum and hexahydride, and gypsum was present in all soil samples taken;
iii) the pH of the soil water falls within a range of 7.35 to 7.95 which is slightly alkaline and within those pH values consistent with a near-neutral solution and was controlled by carbonates;
iv) the corresponding values of electrical conductivity of the soil water ranges from 1.48 to 9.94 deciSiemens per metre (dS/m);
v) the occurrence site is located in glacial till containing porous sand lenses which were laden with dissolved salt;
vi) the total amount of dissolved salts in the sand lenses ranged from 950 to 6,360 milligrams per litre (mg/L), with very little sodium salt present;
vii) the occurrence site corresponds to a groundwater discharge area, which is likely a local flow system; and
viii) the colouration of the soil material indicated that, while there are anaerobic bacteria present, the site is not highly anaerobic.

The high level of dissolved salt present in the soil at the occurrence site is traceable to pre-historic times. The evaporite salt bed stretches from northern Alberta to the south-east corner of Saskatchewan. Presently referred to as the Elk Point/Broadview Syncline Salt Basin, the bedded salt is an evaporite sequence of the middle Devonian age that occurred over the eastern part of the Western Canada Sedimentary Basin. The prairie evaporite is largely halite in composition. It is underlain by mineral dolomites and overlain by dolomitic limestones, which are carbonate-based. The major constituents of the prairie evaporite include sylvite (a potassium chloride mineral), anhydrite (anhydrous calcium sulphate) and carnallite (a potassium chloride salt derivative).

1.9 Metallurgical Testing of the Pipeline Steel

The chemical composition and mechanical properties of the pipe sections from Line 3, remote from the area that failed, were consistent with the pipe specifications at the time of purchase.

The rupture was examined by two independent metallurgical consultants retained by IPL. The metallurgical examination of the fracture area indicated that the pipe fractured along the longitudinal seam, and opened up over a length of 1.87 m (about 6.1 feet). The tape wrap showed poor bonding in some areas, with wrinkles and tape seam separations. Removal of the tape revealed general corrosion along the longitudinal seam weld with the heaviest corrosion corresponding to the centre of the failure. Non-destructive testing of the failure found 27 regions of indications of small colonies of cracking within 150 mm of the longitudinal seam weld, many within the corroded areas of the pipe. Eight similar regions of colonies of cracking were found adjacent to the downstream circumferential weld. All the cracks within the colonies were oriented in the axial direction. Several corroded areas were found to contain shallow colonies of low-pH (more accurately termed near-neutral-pH) stress corrosion cracking (SCC). It should be noted that the term "low pH" has been used by the pipeline industry to draw a distinction with the type of SCC found in the United States referred to as "high pH."

Two large flat areas corresponding to the areas of deepest corrosion were observed on the fracture surface which revealed inter-granular corrosion features as well as secondary cracking. The material analysis indicated that the primary cracking mechanism was trans-granular.

The first consultant concluded that the failure occurred as a result of excessive corrosion together with fatigue cracks at the bottom of narrow and deep corrosion pits, some as high as 70 per cent of the pipe wall thickness. Before the rupture, the original pipe wall thickness had been reduced to 0.6 mm from its original thickness of 7.14 mm. It was concluded that, while the crack initiation may have resulted from SCC, the most likely mode of propagation was considered to be corrosion fatigue. The first consultant arrived at this conclusion based on the presence of sharp corrosion pits, the relatively straight fracture path, and the absence of SCC colonies near the rupture, more specifically at the fracture origin. It was also stated that only colonies of shallow trans-granular SCC cracks, typical of the low-pH trans-granular cracking, were detected and there was no extensive SCC presence confirmed.

The second consultant carried out another metallurgical examination. This examination showed that there may have been some deformation of the pipe surface from the sand-blast cleaning process, which was performed before the start of the first metallurgical examination. This may have led to some cracks being hidden by this grit or sand-blast cleaning process. An SCC colony, remote from the initiation site, which contained approximately 75 cracks, was identified with evidence of crack linking. At the initiation site, the fracture plane was found to be made up of several small parallel cracks which coalesced and grew together. A metallurgical examination of a section of the pipe near the centre of the initiation site showed two large cracks: a main crack and a secondary crack. The main crack did not show significant branching. There was some branching emanating from the secondary crack, which was found to be trans-granular in nature. The examination of an area near the tip of the crack in one of the least corroded areas revealed mostly trans-granular quasi-cleavage features which transitioned into ductile features in the overstressed zone. There was little evidence of multiple cracks or crack branching.

Based on several observations from this second metallurgical examination, including the noted trans-granular quasi-cleavage features, the fact that the fracture plane in the initiation area consisted of coalesced cracks, and the presence of small cracks on the outside diameter surface of the pipe near the fracture site, the second consultant concluded that the failure occurred as a result of excessive corrosion together with low-pH SCC.

1.10 Low-pH Stress Corrosion Cracking

It is now known that low-carbon pipeline steel can suffer from low-pH SCC. This type of cracking phenomenon has been defined as a progressive fracture mechanism which is caused by the simultaneous interaction of a sustained tensile stress at the pipe surface and a corrodent environment. In the case of low-carbon pipeline steel, this is a carbonate/bicarbonate soil condition which has been found to be a very dilute solution of carbonate/bicarbonate acid near but not quite at a neutral environment condition, which sometimes is referred to as “non-classical” SCC. Whether a pipeline will undergo low-pH SCC depends upon the environmental conditions present, the type of exterior pipeline coating, the level of CP, and whether the pipeline steel is susceptible to the low-pH SCC phenomenon. Alloys are generally more susceptible to SCC than pure metals.

Low-pH SCC has been shown to involve trans-granular crack propagation due to a combination of dissolution and hydrogen of pipeline steel by a near-neutral corrosive medium. The factors which contribute to the initiation of low-pH SCC include:

i) a combination of hoop tensile stress (due to the internal pressure of the flowing medium) and residual tensile stress (due to heat treatment welding, grinding or assembly mismatch) which together is above the threshold level of stress for cracking to occur;
ii) a near-neutral slightly corrosive medium in contact with the pipe surface;

iii) an electrochemical potential at the crack within a specific range; and
iv) internal fluctuating pressures.

Engineering research has shown that, for low-pH SCC to occur, all four of these conditions must be present at certain levels. Since maximum pipe stress levels exist on the outside surface of the pipe and discounting the effects of residual and mechanical stresses, low-pH SCC will develop and grow on the outside pipe surface as a series of distinct individual cracks, densely packed together within a defined area. This phenomenon gives rise to the concept of "crack colony." Once a crack colony has been initiated, the colony continues to grow and propagate through various stages of development over time on the pipe surface at a definable growth rate. The rate of crack growth becomes the fifth and determining factor as to whether a pipeline rupture or leak will occur. Due to the variations in the frequency and level of intensity of the four noted factors which promote and initiate low-pH SCC, each crack colony and individual crack within the colony grows and propagates by a certain percentage of the pipe surface and the pipe wall each year. Over time, cracks within a colony will coalesce through a combined mechanical/environmental process, linking together to form a critical crack, i.e. a "significant crack with a crack depth greater than 10 per cent of pipe wall thickness." The level and size of crack linking determine whether a pipeline will rupture or leak. Because these factors are interrelated, the value of each factor will, in turn, control the stress at which cracking will occur for each particular steel. Engineering research has found that altering any one of these four factors could reduce or eliminate the likelihood of a low-pH SCC occurrence.

The susceptibility of the pipeline steel to low-pH SCC relates directly to the propensity of the material to undergo the low-pH SCC process, which coincides directly with the operating pressure of a pipeline system. Research has found that decreasing the level and frequency of internal fluctuating pressures caused by the flowing medium in the pipeline has a reducing effect both on the initiation and propagation of low-pH SCC. In addition to reducing the operating pressure of the pipeline system, the likelihood of low-pH SCC-related pipeline ruptures and leaks can be reduced by applying one or more of the following remedial measures:

i) monitoring of the pipeline for cracks by excavation and non-destructive testing, especially in areas that have been shown to support cracking;
ii) performing periodic hydrostatic re-tests to detect sections of structurally inferior pipe;
iii) minimizing or eliminating internal pressure fluctuations especially during starting and stopping operations;
iv) controlling CP levels within a specified range;
v) performing regular internal coating surveys of the pipeline system to identify zones of coating deterioration and/or disbondment; and
vi) reducing or eliminating the potential for stagnant water build-up adjacent to the pipeline in wet, poorly drained areas through the development of a system-wide, site-specific soils model of the pipeline right-of-way.

Since 1989, IPL commissioned an investigative study which was based upon a program of field examination for SCC in conjunction with other maintenance activities. The results of this investigative study showed that insignificant SCC (crack depth less than 10 per cent of pipe wall) was present at some locations on Line 3. However, as no instances of significant SCC (crack depth greater than 10 per cent of pipe wall) were found, IPL decided that the use of crack detection based in-line inspection (ILI) would provide a more comprehensive approach to the management of cracks from any cause.

1.11 Exterior Polyethylene Tape Coating System on Line 3

During its original construction, Line 3 was coated with a polyethylene tape coating with a total thickness of 13 mils; 9 mils of which was polyethylene tape and the other 4, the self-adhesive backing. The tape coating was field-applied with a one-inch overlap during the taping process after the pipe surface had been wire-brushed to remove any mill scale.

At the time of the installation of the self-adhesive coating, the longitudinal seam of each section of the pipe was oriented between the 3 o'clock position and 9 o'clock position. For pipe with over-bends or under-bends, the longitudinal seam was oriented at the neutral axis of either the 3 o’clock position or 9 o’clock position. Since the pipe had a DSAW longitudinal seam, there was a tendency for the self-adhesive coating to tent over the full length of the longitudinal weld, leaving a narrow area of the pipe surface not in contact with the self-adhesive material of the exterior tape coating. Since the 3 o'clock or 9 o'clock position is the area of highest pipe-to-soil interaction (soil friction) from pipe movement during normal operations, thus the zone of highest soil stresses for the exterior tape coating, there is a tendency for the coating to disbond from the pipe surface. Once a coating has disbonded, this situation permits easy access to and migration along the pipe surface of the surrounding environment; i.e. the groundwater, the bacteria present in the soil and the mineral composition of the soil. As a result of these facts, IPL has changed its construction practice for new and replacement pipe and does not orient the longitudinal seam at the 3 o'clock or 9 o'clock positions.

Although soil stress disbondment of the tape coating often occurs at the longitudinal seam, IPL has found that the tape coating disbondment typically extends over a longer circumferential distance rather than immediately over the longitudinal seam, thus expanding the corrosion problem into a general corrosion problem.

1.12 *Analysis of Pipe Corrosion Products and Polyethylene Tape Residues*

The examination of pipe corrosion products and polyethylene tape coating residues which were found at the occurrence site revealed the following characteristics:

i) gypsum precipitates (calcium sulphate hydrates) were dominant as a residue on the polyethylene exterior tape;
ii) pipe corrosion samples showed both oxidized and reduced iron, scale components dominated by magnetite, goethite, and siderite; and
iii) some soil adjacent to the pipe and scale on the pipe was dominated by calcite (calcium carbonate) precipitates.

1.13 *History of Previous Ruptures, Leaks and Pipe Replacements on Line 3*

Beginning in 1989, five pipeline occurrences have happened on Line 3 of the IPL system. Four of these occurrences took place in the general vicinity of the present occurrence, at MP 506.6830 and one occurred at MP 722.8. A detailed review of the metallurgical findings of these previous occurrences was carried out to determine whether low-pH SCC may have been a factor in some of these previous occurrences (TSB Engineering Branch report No. LP 47/96). The following previous occurrences on Line 3 were reviewed:

i) MP 478.87, 10 September 1994, TSB occurrence No. P94H0045;
ii) MP 518.87, 16 June 1995, TSB occurrence No. P95H0023;
iii) MP 548.86, 13 November 1995, TSB occurrence No. P95H0047;
iv) MP 549.5, 09 January 1989, investigated originally by the NEB; and
v) MP 722.8, 17 October 1990, TSB occurrence No. P90H0036.

Details with respect to the pipe outside diameter, wall thickness, location of the longitudinal seam, location of the failure, coating type, operating pressure and remaining wall thickness at the time of the final overstress failure are listed in Appendix A. Based on the metallurgical evidence gathered from these occurrences, the metallurgical mode of failure for each of the incidents was identified as follows:

i) at MP 478.87, general surface corrosion led to extreme thinning of the pipe wall and a pipeline leak;
ii) at MP 518.87, general corrosion led to extreme thinning and a pipeline rupture (refer to TSB occurrence report No. P95H0023);
iii) at MP 548.86, the pipeline ruptured and fatigue striations were observed on the failure surface (refer to TSB occurrence report No. P95H0047);
iv) at MP 549.5, the pipeline ruptured and fatigue striations were observed on the failure surface; and
v) at MP 722.8, the pipeline ruptured and sulphide stress cracking was identified as the failure mechanism.

1.14 Susceptibility Investigation Action Plan for Line 3

In response to a corrosion-related pipeline rupture on Line 3 which occurred on 16 June 1995, an investigative program, referred to as the Susceptibility Investigation Action Plan (SIAP), was developed by the IPL. The purpose of this action plan was to determine whether similar corrosion patterns to those found at the occurrence site of 16 June 1995 existed elsewhere on the pipeline system and, if present, to decrease the potential for a similar pipeline rupture. The particular type of corrosion found on Line 3 has a typical narrow, axial, external wall loss morphology that had previously been detected during an internal inspection of Line 3 using a magnetic flux ILI tool. However, this type of corrosion produced corrosion depth signals which, unlike the vast majority of corrosion morphologies, were underestimated by the computer interpretation algorithms. As part of the ILI crack detection tool development, two coupons were removed at MP 506.09 and MP 507.92. There were no pipeline leaks associated with these two locations. However, an analysis was performed on the two coupons and the following metallurgical information was obtained:

i) at MP 506.09, while the pipe surface appeared to show possible SCC colonies, the extensive surface corrosion prevented a clear identification of any cracking mechanisms; and
ii) at MP 507.92, although SCC colonies were present, it was concluded that the cracking in the toe of the weld was fatigue in nature.

IPL's SIAP program is designed to identify all situations of narrow, axial, external corrosion (NAEC) on Line 3 between Edmonton and Gretna, Manitoba, by re-calibrating the metal loss sizing measurement parameters of the ILI device. Eliminating the rupture potential associated with NAEC defects forms the central objective of IPL's SIAP, which is outlined as follows:

i) define the characteristics associated with NAEC-type defects found under disbonded exterior polyethylene tape coating;
ii) analyse the morphology of metal loss within narrow bands for the NAEC-type defect;
iii) determine the environmental conditions, such as soil type, groundwater movement and electrolyte chemical composition, that affect corrosion growth rates;
iv) select sites that may be susceptible to similar corrosion that have been potentially underestimated by the analysis of the results of the four ILIs carried out in 1979, 1990, 1994, and 1994-1995; and
v) conduct an excavation program to reduce the rupture potential associated with NAEC.

As a component of the overall program, the results of the 1979, 1990 and 1994 ILI runs which were carried out specifically for corrosion identification have been superimposed upon the results of the 1994-1995 internal inspection, which was run specifically to identify cracks in the pipeline. Any anomalies found from this comparison work would be evaluated against the corrosion evaluation and treatment requirements for external corrosion set out in the pipeline standards of the Canadian Standards Association (CSA).

In force since 1994, the current edition of CSA standard CAN/CSA-Z662-94, entitled *Oil and Gas Pipeline Systems Standard*, section 10.8.2, titled "Evaluation and Treatment of Localized External Corrosion Pitting on Pipe," permits localized corrosion pits to 80 per cent of the nominal wall thickness of the pipe, provided that the calculated maximum permissible length of the corrosion is not exceeded. This standard has the same corrosion limits as those specified in previous editions of CSA standards for oil pipelines, most notably standard CAN/CSA-Z183-M86, in effect from 1986 until 1990, and standard CAN/CSA-Z183-M90, in effect from 1990 until 1994. Earlier editions of the CSA standard were in effect in 1989 when IPL initiated the ILI program on Line 3 for purposes of corrosion detection and repair determination. Using the formula set out in the CSA standard, the maximum allowable longitudinal length for the corroded area can be determined. During the application of the CSA standard, IPL found that, in numerous cases, the amount of corrosion damage on Line 3 exceeded the maximum length limits established by the CSA standard.

Since the CSA standards are viewed as very conservative with respect to the corrosion criteria calculations, some pipeline operators use the Engineering Critical Assessment (ECA) method permitted by the CSA standard. In 1989, IPL requested and received permission from the CSA to use the ECA method in lieu of the specific requirements outlined in section 10.8.2 of the CSA standard. The ECA was not designed to be applied to defects where cracks were coincident with metal loss.

During the 1995 SIAP phase of the Line 3 work carried out by IPL, all ECAs were performed on excavated pipe after the surface had been inspected for the presence of cracks. The location that failed on 27 February 1996 had not, however, been identified by the SIAP as requiring evacuation. While IPL does not agree that cracks cannot be assessed using an appropriate ECA, IPL was of the opinion that there was no need to evaluate the combined action of cracks and metal loss in 1995, as no defects or occurrences similar to the Glenavon occurrence had been found during the 1995 program.

Other programs have also been developed by IPL to address the rate of growth of both corrosion and cracks. In addition, a program has been developed to prioritize sections of Line 3 based on pressure fluctuations. These additional programs have been addressed in more detail in the Operational Reliability Assessment Program of March 1997.

1.15 Initiatives Taken after the Occurrence

On 29 February 1996, the NEB sent a letter concerning this occurrence to IPL. In its letter, the NEB directed IPL to show cause why the NEB should not direct IPL, from the Regina pump station (MP 437.58) in Saskatchewan to the Gretna pump station (MP 772.01) in Manitoba, to: reduce the MAOP to 80 per cent of NEB-approved levels; hydrostatically re-test this section of Line 3 in accordance with the CSA standard; submit a pipeline integrity evaluation for Line 3; and submit details of the re-testing program and the integrity evaluation by 29 March 1996.

On 07 March 1996, IPL replied that it concurred with the NEB safety concerns expressed in the 29 February 1996 letter. Covering 122.3 miles (about 197 km) of the IPL system from IPL's Odessa pump station (MP 473.47) in Saskatchewan to IPL's Cromer pump station (MP 595.8) in Manitoba, IPL responded with the following program:

i) a temporary operating pressure restriction to 80 per cent of the MAOP has been established for this section of the system;
ii) a hydrostatic re-testing program in accordance with the testing requirements for new pipeline construction contained in standard CAN/CSA-Z662-94, entitled *Oil and Gas Pipeline Systems*, has been put in place for this section;
iii) additional ILI surveys are being done in this section;
iv) additional excavations are continuing to be done in this section to confirm the acceptability of the ILI data; and
v) an Operational Reliability Assessment that addresses the long-term program for integrity management on Line 3, with the filing of program details by 29 March 1996, has been developed.

On 14 March 1996, in response to IPL's 07 March 1996 letter, the NEB directed IPL to address the safety and environmental concerns in the 122.3-mile section of the pipeline system from the Odessa pump station to the Cromer pump station by:

i) reducing the MAOP to 80 per cent of the authorized levels;
ii) hydrostatically re-testing the pipeline and filing the results with the NEB; and
iii) submitting a pipeline integrity evaluation.

The NEB directed IPL to submit a plan and proposed timetable for implementing these directives by 29 March 1996.

2.0 Analysis

2.1 Introduction

The metallurgical examination identified stress overload at a pre-existing external surface defect, referred to as an NAEC-type defect, in the pipe wall of Line 3, assisted by low-pH SCC, as the source of the pipe wall weakness that led to the occurrence. As the pipeline rupture occurred during the winter, in the middle of a farmer's field, a large amount of the released crude oil was recovered. The contaminated soil was removed and the resulting impact on the environment was negligible. The rupture and loss of internal operating pressure were immediately acted upon by IPL operations personnel, shutting down Line 3 and triggering a series of emergency procedures by IPL field staff.

From the time when IPL first identified NAEC-type defects on Line 3, it has been aware of the risk of a pipeline failure on Line 3. While IPL has continuously performed CP surveys of Line 3 and continuously obtained favourable results from these surveys, it is aware that the polyethylene coating is shielding the positive effects of the CP system, permitting the creation of a pipe surface environment which gives rise to NAEC-type defects. The analysis of this occurrence will focus on: the policies and procedures employed by IPL, as outlined in the SIAP, for identifying, excavating, verifying, and repairing areas susceptible to NAEC-type defects; the exterior polyethylene tape coating and the environmental conditions which led to the NAEC-type defect surface corrosion; the presence of low-pH SCC; the history of previous occurrences in the Glenavon-to-Langbank section of the pipeline system; and exterior pipe cleaning methods employed by IPL.

2.2 Consideration of the Facts

2.2.1 Susceptibility Investigation Action Plan for Line 3

Initiated in 1995, the SIAP clearly outlines the policies and procedures that the field personnel will be following to eliminate the rupture potential of Line 3 associated with NAEC-type defects. Since 1979, IPL has diligently performed four ILI surveys of Line 3, with three of the ILI surveys carried out since 1990. While the original intent was to identify corrosion on Line 3, the restated purpose of the ILI surveys is to identify the exact location of these NAEC-type defects, but not associated cracks. Once these defects are located, IPL field crews will initiate the appropriate action outlined in the SIAP. As a quick means of prioritizing any corroded section of the pipeline system, the results of each survey have been and will be superimposed upon the results of previous surveys to provide a more comprehensive means of defect determination. From the ILI surveys to date, it has been shown that Line 3 is heavily corroded with the NAEC-type defect. It has also been found that the ILI survey equipment did not accurately identify nor accurately size all the locations on the pipeline system which had been affected by the NAEC-type defects.

A component of the SIAP is the application of the results of an ECA to those zones of NAEC-type defects identified by the ILI surveys. Historically, the ECA has been used as an engineering tool to determine the structural integrity and viability of a system or its components, in this case the long lengths of NAEC-corroded pipe which do not meet the requirements of the CSA standard, and the operating pressure of the pipeline. While the ECA has its merits and applications, the application of an ECA to a structure that is susceptible to cracking or that contains cracks is beyond the scope of an ECA. Since cracks are viewed as unstable to perform an ECA, any results obtained from an ECA should be viewed with extreme caution.

A contributing factor to the rupture was low-pH SCC. Low-pH SCC develops under disbonded polyethylene exterior coatings in the presence of a carbonate/bicarbonate solution, and both of these conditions existed at the occurrence site. By its very nature, low-pH SCC is an unstable cracking mechanism, and has been found to possess a definable crack growth rate. While this section of the system meets the criteria set out by IPL's ECA, the presence of SCC accelerated an already heavily NAEC-corroded section of pipe. The fact that this section passed the criteria established by the SIAP raises concern respecting other sections on the pipeline system where NAEC-type defects exist.

While the establishment of the SIAP has merit, IPL's SIAP appears to possess certain inherent deficiencies. Firstly, the SIAP does not address the rate of growth of NAEC-type defects that would be applied to the results of an ILI survey after these results have been received for evaluation. Because of the nature of the problem, there may be locations on the pipeline system which are experiencing a higher rate of NAEC growth than adjacent NAEC areas. Secondly, the SIAP does not address the rate of growth of colonies of cracks or other types of surface defects within and/or adjacent to the NAEC-corroded areas which may influence the mechanics of the structure under normal operating conditions. Thirdly, the SIAP does not appear to address pressure fluctuations from the starting and stopping of pumping units which can initiate very large pressure waves within the pipeline system and have historically resulted in pipeline ruptures.

2.2.2 Exterior Polyethylene Tape Coating and Environmental Conditions

The self-adhesive polyethylene tape coating system used by IPL on Line 3 is particularly susceptible to NAEC-type defects under specific environmental conditions, such as those found at the subject occurrence site. This type of exterior coating system shows a much higher susceptibility to producing NAEC-type defect conditions than other external tape coatings. The self-adhesive polyethylene exterior coating system used on Line 3 has been found to experience both a tenting effect over the full length of the longitudinal weld as well as disbondment and/or deterioration over the body of the pipeline. CP survey measurements taken by IPL employees over several years indicated full CP coverage in the section of the pipeline system containing the rupture. This double situation of tenting and disbonded and/or deteriorated coating, which acts as an electrical shield to the CP current, is referred to as CP shielding. With this phenomenon, impressed current from the CP system cannot access exposed metal which lies under the coating. This electrical shielding causes changes in the potential gradient of the CP system; i.e., in areas of insufficient CP current. This in turn produces an area on the pipeline of insufficient CP defence against metal loss; in this case, NAEC-type defects. Over time, this condition of CP shielding has been shown to give rise to NAEC-type defects, leading to pipeline ruptures. This presumption assumes that all factors necessary for NAEC-type defects to occur on the pipeline system are present at a specific location on the pipeline system.

Numerous field investigations by IPL have found tenting of the external pipe coating over the full length of the longitudinal seam weld. The tenting adjacent to the longitudinal seam weld has created a channel along which the groundwater and associated ground mineral salts and ground bacteria can travel the length of a joint or joints of pipe. Mineral salts and bacteria in the soil and groundwater, when combined with CP shielding, act to accelerate the process of NAEC-type defects. However, the role played by mineral salts and bacteria in this process of disbondment and/or deterioration is not well known and not well understood. While much time and resources have been expended by IPL to understand the NAEC-type defect phenomenon on its pipeline system, little understanding exists as to the interaction between bacteria, the groundwater, naturally occurring mineral salts, the exterior coating primer, and the polyethylene tape coating. This interaction then gives rise to the existence of NAEC-type defects on Line 3.

2.2.3 Low-pH Stress Corrosion Cracking on Line 3

A component of IPL's SIAP is the establishment of a soils model. While the soils model is still in the development stage, its purpose will be to assist company personnel in identifying the exact locations of soil types on the pipeline system that are known or have been shown to encourage the development of low-pH SCC. In its final form, the soils model will cover all IPL facilities from Edmonton to Gretna. Since 1977, pipeline companies have found low-pH SCC on their pipeline systems operating across Canada through direct field experiences and experimental research, and reported on these situations. As noted in the review of previous occurrences on the IPL system, IPL has found low-pH SCC on its pipeline system in association with other mechanisms that have led to ruptures and leaks. However, metallurgical investigations determined that the presence of the low-pH SCC did not contribute directly to the ruptures or leaks. IPL did not begin development of a soils model until it became obvious that low-pH SCC would continue to develop across the pipeline system and contribute directly or indirectly to pipeline ruptures and leaks. Until the completion of the ILI crack detection program, IPL personnel will be unable to accurately identify the soil conditions on its pipeline system which contribute directly to low-pH SCC as a means of preventing ruptures and leaks.

2.2.4 *Other Environmentally Assisted Cracking Mechanisms on Line 3*

The metallurgical review of previous pipeline occurrences on the IPL system identified additional environmentally assisted cracking (EAC) mechanisms, other than SCC, that have contributed to pipeline ruptures and leaks on the system.

EAC is a generic term used to describe the cracking and fracture of metals under the combined action of stress and an environment, which is usually an aqueous environment. EAC in an aqueous medium may be classified into a number of sub-types. When the loading stress is alternating, the term "corrosion fatigue" (CF) is used. When the cracking occurs under static stress in a corrosive medium, the term SCC is used, although recent research has shown that some types of cracking (near-neutral-pH SCC) currently classified as SCC require a component of dynamic loading to achieve significant growth rates. Cracking attributed to SCC may include a variety of micro-mechanisms, the best known being anodic dissolution and hydrogen-assisted cracking (HAC). If the crack propagates by an anodic process, either a dissolution of metal atoms or a repeated formation and rupture of an anodic film at the crack tip, the cracking is undoubtedly a type of SCC, an example of which is the cracking of pipeline steel in a high-pH SCC solution. On the other hand, if the crack propagation is mainly a result of a mechanical micro-fracture process assisted by hydrogen at the crack tip, then the term hydrogen embrittlement (HE) or HAC is more precise. The exact mechanism(s) for the interaction between hydrogen and metal is still vigorously debated, the main models being de-cohesion and enhanced crack-tip plasticity. When the hydrogen is produced as a result of a natural corrosion reaction, rather than by cathodic charging, the cracking is sometimes classified as SCC. However, cracking of steels under adequate CP is more precisely described as HAC since, under sufficient electrochemical polarization, anodic processes (dissolution and/or passivation) are suppressed.

The SIAP is limited in scope to NAEC-type defects and is silent on IPL's policies and procedures for the detection, excavation, verification and repair of the other types of EAC mechanisms identified from the review of previous occurrences, which are present in association with NAEC-type defects.

2.2.5 *History of Previous Pipeline Occurrences - Glenavon to Langbank*

Since 1989, the Glenavon-to-Langbank section of IPL's Line 3 has had a history of ruptures, leaks, pipe replacements and repairs related to general corrosion or NAEC-type defects, sometimes in association with an EAC mechanism. The review of the ILI survey logs for this section of the pipeline shows the presence of extensive NAEC-type defects in varying degrees.

The geometry of the failed section of pipe indicated that Line 3 ruptured as a result of the direct effects of NAEC-type defects. Assisting in and contributing to this NAEC process was low-pH SCC. The historical investigation of ruptures, leaks, pipe replacements and repairs found that, in addition to low-pH SCC, other types of EAC mechanisms, such as sulphide stress corrosion and fatigue, have contributed to or caused leaks, repairs and pipe replacements on this section of the pipeline system.

When a company designs a new pipeline system or modifies an existing system, the various CSA standards and NEB regulations provide guidance and ensure a properly designed system which satisfies existing minimum safety and operational requirements. These standards and regulations have evolved over time to represent the best engineering design criteria, based on a consensus of the pipeline industry. The various standards and regulations dictate that the pipeline will be:

i) designed and fabricated to meet applicable material criteria;
ii) installed and coated to meet applicable construction criteria;
iii) hydrostatically tested to ensure its design, prior to normal operations;
iv) cathodically protected to ensure its integrity against corrosion;
v) internally inspected to ensure its structural integrity; and
vi) repaired to meet applicable reconditioning criteria.

When IPL built Line 3 with the guidance of CSA standards, it had no reason to suspect that the buried pipe would experience an NAEC-type defect condition in association with various EAC mechanisms. The CSA standards are very specific with respect to the coating requirements for new and/or repaired pipelines; however, they are silent on the question of the method(s) of identification and repair of NAEC-type defects and associated EAC mechanisms.

While the CSA standards do not give directions to the pipeline industry with respect to safe and effective methods of addressing an NAEC-type defect condition, the investigation found that IPL has developed in-house policies and procedures on NAEC-type defect identification, excavation, verification and repair. IPL has established company standards related to NAEC-type defects; however, the Canadian pipeline industry has not established national standards applicable to this type of NAEC pattern.

2.2.6 Exterior Pipe Cleaning Methods

When there is a rupture or leak on a crude oil pipeline system and before a metallurgical investigation can be initiated, the cleaning of the external and internal surfaces of the failed section of pipe becomes the first priority. Investigative work cannot begin before the spilt crude oil is removed. In the case of this investigation and previous investigations of ruptures and leaks on the IPL system, the standard procedure has been to grit or sand-blast the pipe surface clean. By its very nature, the sand-blast cleaning process consists of directing pressurized grit or grains of sand at the surface of the pipe to be cleaned. The particles are propelled at high speed towards the pipe surface, resulting in the spilt crude oil being blown away from the surface of the pipe. Before this investigation, there has never been any evidence to suggest that the sand-blast cleaning process in any way distorted the structure of the pipe surface. However, this investigation found that colonies of low-pH SCC may have been masked by the sand-blast cleaning process. It is well known that the cracking morphology of fatigue-type cracks and that of low-pH SCC are very similar. The morphology of the cracking mechanism, together with the presence of cracking colonies, sets these two mechanisms apart. Historically, occurrences exhibiting fatigue striations have taken place on IPL's pipeline system. In each of those cases, the exterior pipe surface had been cleaned using the sand-blast cleaning technique. Had colonies of low-pH SCC been present, these colonies could have been masked by the process and the wrong failure mode could have been identified.

2.2.7 Initiatives Taken after the Occurrence

In response to the three pipeline ruptures that have occurred on Line 3 in the Odessa-to-Cromer section of the IPL system between June 1995 and February 1996, the NEB directed IPL to show cause why the NEB should not order IPL to undertake certain safety-related activities on Line 3 from Edmonton to Gretna. In reply to the NEB request, IPL established a company-designed safety program (referred to as safety program) which encompasses the spirit and intent of the NEB letter with emphasis on two specific sections of the system, namely the 196.8-km section from Odessa to Cromer and the 81-km section from Cromer to Souris. This revised safety program has been accepted by the NEB.

The TSB investigation found that tenting of the polyethylene, self-adhesive exterior tape coating system used on Line 3 permitted the aqueous and associated environment around the pipe to migrate into the unprotected area under the tented polyethylene coating. This situation permitted NAEC-type defects and EAC-type mechanisms to be created and to grow. Accelerating the corrosion process is the presence of an aggressive environment in the form of bacteria and high levels of naturally occurring mineral salts. Since IPL's impressed CP system has been shielded from protecting the exterior surface of the pipe due to disbonding and tenting of the self-adhesive, polyethylene tape coating over the full length of the longitudinal seam weld, NAEC-type defects together with EAC-type mechanisms are continuing to exist and to grow in length and depth with time.

The overall thrust of the safety program centres on initiatives to determine the condition of Line 3 as it presently exists in the ground. Not all elements have been addressed in the safety program but are under active investigation by IPL in the overall Integrity Management Program. The use of a hydrostatic re-test by IPL has merit in that it permits destructive identification of those locations on the pipeline system which are the weak joints in Line 3 between Odessa and Cromer that may not have been identified during the 1996 ILI and excavation program. However, IPL’s safety program does not address the long-term, detrimental effects of the ongoing NAEC-type/EAC-type growth cycle within the hydrostatically re-tested sections of Line 3 as well as for those sections of Line 3 which have not been hydrostatically re-tested. It is general knowledge that pipelines that have successfully passed a hydrostatic re-test fail some time later for the specific reason that a hydrostatic re-test was performed.

The safety program has addressed the immediate condition of Line 3 between Regina and Gretna through further ILI validation work and additional site-specific digs. However, the safety program does not address the long-term viability and security of operation of the structurally reduced pipe steel over the 122.3 miles of Line 3 to sudden pressure surges and other operational malfunctions. Instead, these issues are managed by the company's pipeline control system and are outside of the scope of specific actions implemented by IPL because of the Glenavon occurrence. While the safety program will make use of additional ILIs and site-specific digs to confirm the results of the ILI, the investigation found deficiencies with the company's SIAP which have not been addressed. The safety program does not address the remainder of Line 3 which is not subject to further review.

When IPL was building and coating Line 3, self-adhesive exterior tape coating systems became the norm and were used by IPL for the construction and coating of other new pipeline systems (other than Line 3) by the company. As well, other pipeline companies in Canada found that, during the construction and coating of new facilities, self-adhesive, polyethylene exterior tape coatings were easy to apply. The IPL safety program does not address the condition of the other pipelines in the IPL system that may have been coated with a self-adhesive exterior tape coating system. The NEB has not addressed the issue of this type of exterior coating on other pipeline systems under federal jurisdiction.

3.0 Conclusions

3.1 Findings

1. The rupture of Line 3 initiated in a zone of narrow, axial, external corrosion (NAEC) that was located adjacent and running parallel to the longitudinal seam weld of the pipe and assisted by low-pH stress corrosion cracking (SCC).

2. Colonies of SCC were identified in the vicinity of the NAEC-type defect which led to the rupture.

3. Further indications of SCC may have been masked by the sand-blast cleaning process before the initiation of the metallurgical examinations.

4. NAEC and SCC are known to occur under polyethylene exterior coatings which are known to disbond and/or degenerate, thus creating an area on the pipe surface which is shielded from the cathodic protection (CP) system and where the external environment can gain easy access.

5. The exterior environment around the buried pipeline was found to contain metal poisons, such as bacteria and mineral salts, which have been found to be directly related to the initiation and propagation of NAEC-type defects and environmentally assisted cracking (EAC) mechanisms.

6. There have been four pipeline ruptures in the general area from the Glenavon to the Langbank pump stations in Saskatchewan; three of these ruptures occurred in a nine-month period.

7. Interprovincial Pipe Line Inc. (IPL) field investigation work has found NAEC-type defects over long stretches of Line 3.

8. IPL has developed a Susceptibility Investigation Action Plan (SIAP) which sets out the policies and procedures of the company for reducing the rupture potential of Line 3 based on the results of identifying critical defects in the field and then applying an Engineering Critical Assessment of NAEC-type defects, but the SIAP does not address the rate of growth of NAEC-type defects and the role of pressure fluctuations on NAEC-type defects in the operating pipeline.

9. A key component of the SIAP for NAEC-type defect site identification is the superimposing of the results of four in-line inspections of Line 3.

10. IPL's SIAP did not identify the site of the NAEC-type defect in association with the EAC mechanism at Mile Post 506.6830 as requiring immediate investigation and repair.

11. The SIAP has not been designed to address the identification, verification and rate of growth of other EAC mechanisms which have been found in association with pipeline ruptures and leaks on Line 3.

12. In response to this occurrence and a directive from the National Energy Board (NEB), IPL has initiated a safety program which is concentrated in a 122.3-mile (196.8-km) section of the pipeline system from Odessa to Cromer.

13. The safety program has addressed the immediate condition of Line 3 between Regina and Gretna.

14. While the scope of the NEB's safety directive to IPL addresses all sections of Line 3, especially the 196.8-km section between Odessa and Cromer, the scope of the NEB's safety directive has not been expanded to other pipeline systems which may have been coated with self-adhesive, polyethylene exterior tape coatings by IPL and other pipeline companies.

15. The NEB and the CSA have not established standards of acceptability for NAEC-type defects found alone or in conjunction with EAC-type mechanisms for operating pipelines in Canada.

3.2 Cause

The rupture was caused by excessive narrow, axial, external corrosion located adjacent and running parallel to the longitudinal seam weld of the pipe, which was assisted by low-pH stress corrosion cracking and was not identified through the company's ongoing pipeline integrity program called the Susceptibility Investigation Action Plan.

4.0 Safety Action

4.1 Action Taken

4.1.1 IPL's Integrity Management Programs

Immediately after the occurrence, Interprovincial Pipe Line Inc. (IPL) undertook safety action which consisted of reducing the maximum allowable operating pressure, using ultrasonic in-line inspection (ILI) tools to better detect and assess the occurrence of narrow, axial, external corrosion (NAEC), using ILI crack detection tools to locate areas of environmentally assisted cracking (EAC) mechanisms, developing corrosion growth models, developing soil landscape models to assist in identifying locations on Line 3 that are more susceptible to low-pH stress corrosion cracking (SCC), hydrostatically re-testing Line 3 of the Enbridge Pipeline Inc. (Enbridge) pipeline system and submitting a pipeline integrity study. IPL's Susceptibility Investigation Action Plan (SIAP) has now been subsumed within Enbridge's Integrity Management Programs (IMPs). The new IMPs are ongoing programs designed to address NAEC-type defects associated with self-adhesive tape-wrapped pipe on Line 3 and other sections of the Enbridge pipeline system. The IMPs for the detection and assessment of NAEC-type defects have been completed for all of Line 3 between Edmonton and Gretna. Since March 1996, over 990 discrete locations on Line 3 have been excavated, assessed and repaired. Enbridge has used ILI crack detection tools on Line 3 and has completed the internal inspection of the Regina-to-Gretna portion of Line 3. Enbridge intends to complete the ILI crack detection inspection of Line 3 from Edmonton to Regina within the next three years.

4.2 Action Required

4.2.1 Narrow, Axial, External Corrosion

The IMPs set out the policies and procedures of the company for reducing the rupture potential of Line 3 based upon identifying critical defects in the field and then applying an Engineering Critical Assessment (ECA) of the NAEC defects. However, the rate of growth of NAEC-type defects found in association with EAC mechanisms and the role of pressure fluctuations on this type of defect are not fully addressed in the IMPs. The detection of these types of defects is still unreliable. The ECA assessment process is also unreliable because it was not designed to be applied to defects where cracks were coincident with metal loss. For the Glenavon region, three defects that were properly identified were not captured during the assessment process. Subsequently, the pipeline ruptured. Notwithstanding the actions taken by the company under the IMPs, the Board believes that the risks associated with NAEC-type defects found in isolation or in association with EAC-type mechanisms persist. Therefore, the Board recommends that:

> The National Energy Board, in collaboration with the provincial authorities, the industry representatives and the Canadian Standards Association, re-assess methods for the detection and

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2 Interprovincial Pipe Line Inc. changed its corporate name to Enbridge Pipeline Inc. on 13 October 1998.

assessment of narrow, axial, external corrosion defects found in isolation or in association with environmentally assisted cracking mechanisms.

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4.3 Safety Concern

4.3.1 Self-Adhesive Coatings

The Board is concerned about the absence of programs to mitigate the risks presented by the consequences of disbondment of self-adhesive coatings on other pipeline systems. Self-adhesive coatings on pipelines are known to disbond, making the pipeline system susceptible to general corrosion, NAEC-type defects and EAC-type mechanisms, in combination or alone.

This report concludes the Transportation Safety Board's investigation into this occurrence. Consequently, the Board, consisting of Chairperson Benoît Bouchard, and members Maurice Harquail, Charles Simpson and W.A. Tadros, authorized the release of this report on 14 April 1999.

Appendix A - History of Present and Previous Ruptures, Leaks and Pipe Replacements on Line 3

MP	O.D. (mm)	W.T. (mm)	Grade (MPa) & Year Installed	Pressure (kPa)	Coating Type	Location of Long Seam	c
478.87	864	7.14	359 1965	2,896	PE tape	2:30	3
506.68	864	7.1	359 1968	4,137	PE tape	3:00	bo
518.87	864	7.14	359 1968	3,650	PE tape	9:00	
548.86	864	7.14	359 1965	3,468	PE tape	11:00	t
549.5	864	7	359 N/A	N/A	PE tape	10:30	l
722.8	864	7.4	359 N/A	2,068	PE tape	6:00	

MP = Mile Post
W.T. = wall thickness
O.D. = outside diameter
PE = polyethylene
N/A = not available
long seam = longitudinal seam

Appendix B - Glossary

API	American Petroleum Institute
CCO	Control Centre Operator
CF	corrosion fatigue
close survey	close pipe-to-soil potential survey
CP	cathodic protection
CSA	Canadian Standards Association
DSAW	double-submerged arc-welded
dS/m	deciSiemens per metre
EAC	environmentally assisted cracking
ECA	Engineering Critical Assessment
ECC	Edmonton Control Centre
Enbridge	Enbridge Pipeline Inc.
HAC	hydrogen-assisted cracking
HE	hydrogen embrittlement
ILI	in-line inspection
IMPs	Integrity Management Programs
IPL	Interprovincial Pipe Line Inc.
km	kilometre(s)
km/h	kilometre(s) per hour
kPa	kilopascal(s)
long seam	longitudinal seam
m	metre(s)
MAOP	maximum allowable operating pressure
mg/L	milligram(s) per litre
mm	millimetre(s)
MP	Mile Post
MPa	megapascal(s)
MST	mountain standard time
mV	millivolt(s)
NAEC	narrow, axial, external corrosion
NEB	National Energy Board
NPS	nominal pipe size
O.D.	outside diameter
PE	polyethylene
psig	pound(s) per square inch gauge
RCMP	Royal Canadian Mounted Police
SCADA	Supervisory Control and Data Acquisition

SCC	stress corrosion cracking
SIAP	Susceptibility Investigation Action Plan
SMYS	specified minimum yield strength
TSB	Transportation Safety Board of Canada
U.S.	United States
UTC	Coordinated Universal Time
W.T.	wall thickness