PIPELINE OCCURRENCE REPORT

NATURAL GAS PIPELINE RUPTURE

TRANSCANADA PIPELINES LIMITED
LINE 100-3, MAIN LINE VALVE 5-3 + 15.049 KILOMETRES
NEAR CABRI, SASKATCHEWAN
02 DECEMBER 1997

REPORT NUMBER P97H0063

The Transportation Safety Board of Canada (TSB) investigated this occurrence for the purpose of advancing transportation safety. It is not the function of the Board to assign fault or determine civil or criminal liability.

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Summary

At 0742 Central standard time on 02 December 1997, a rupture occurred at an area of external corrosion on the TransCanada PipeLines Limited 914-millimetre outside diameter Line 100-3 at main line valve 5-3 + 15.049 kilometres near Cabri, Saskatchewan. Approximately 3 252 × 10^3 cubic metres of natural gas was released as a result of the rupture. The gas ignited immediately, resulting in damage to the surrounding soil and vegetation. The main fire self-extinguished within 20 minutes of the line break.

Ce rapport est également disponible en français.

Other Factual Information

Within three minutes of seeing a fireball to the east of Compressor Station 5 near Cabri, Saskatchewan, TransCanada PipeLines Limited (TCPL) personnel at that station initiated an all-line isolation downstream of the station in accordance with TCPL's *Emergency Procedures Manual* (EPM). Within 12 minutes of the line break, the pressure in Line 100-3 decayed to the extent that the low-pressure shut-off device on main line valve (MLV) 6-3 was activated. Since all remote tie-over valves between Stations 5 and 9 were in the closed position, the normal operating position, the closure of MLV 6-3 isolated the affected section of mainline.

Within 12 minutes of the line break, the local police and TCPL personnel set up road blocks on the two access roads to the rupture site. The main fire self-extinguished within 20 minutes of the line break and only stubble fires remained. The local fire department was on site to monitor these fires and to take action if necessary.

TCPL excavated Line 100-3 upstream and downstream of the rupture site. It determined that although only 25 metres (m) of pipe was damaged by the rupture and fire, corrosion at other locations on the line dictated that a longer replacement section was advisable. Therefore, approximately 73 m of pretested new pipe was installed. Following the occurrence of 02 December 1997 but before 19 December 1997, Line 100-3 between MLV 5 and MLV 6 was initially returned to service at a reduced operating pressure of 5 380 kilopascals (kPa). On 19 December 1997, a magnetic flux leakage (MFL) internal inspection tool was run in Line 100-3 between MLV 2 and MLV 17 to verify the integrity of that section of line. Upon completion of internal inspection activities from MLV 2 to MLV 17, the section of pipeline from MLV 3 to MLV 17 was returned to service. Several investigative digs conducted as a result of anomalies identified during that inspection resulted in two pipe replacements and one repair. After these repairs, the section of Line 100-3 from MLV 2 to MLV 3 was placed back in service on 22 December 1997.

In the vicinity of the rupture, TCPL has six parallel pipelines: Lines 100-1, 100-2, 100-3, 100-4, 100-5 and 100-6, located within a 67 m right-of-way. An initial site survey following the rupture indicated that Line 100-2 had moved a maximum of 10 centimetres (cm) horizontally and 8 cm laterally. As a precautionary measure, once Line 100-2 was daylighted, TCPL replaced approximately 30 m of pipe and the line was placed back in service on 08 December 1997. Before 02 December 1997, Line 100-2 had been excavated in the vicinity of the rupture as part of an investigative dig program following an MFL internal inspection of that line. Following that inspection, the line had been re-coated, back-filled and returned to service. TCPL was of the opinion that the displacement of Line 100-2 found by the survey team at the time of the occurrence resulted from the previous back-filling operation.

Following the rupture, Lines 100-1 and 100-4 were also excavated adjacent to the rupture site and inspected for damage. Since there was no damage, the lines were back-filled and returned to service by 10 December 1997.

The same right-of-way as the ruptured section of pipe contains a short section of line abandoned in 1969 due to severe pitting corrosion as a result of poor coating quality and the presence of sulphate-reducing bacteria.
On 27 January 1998, TCPL hosted an open house in Cabri. To handle the interests and concerns of the local population, there were displays regarding TCPL's pipeline maintenance program, its 1998 construction plans, the 02 December 1997 rupture, and the MFL in-line inspection tool. TCPL personnel were on hand to respond to questions, concerns and points of interest. Three hundred and fifty members from the community attended.

The TSB Engineering Branch determined that the pipeline ruptured as a result of localized wall thinning due to external corrosion and that the corrosion had occurred where the pipe coating had either been damaged or become disbonded (TSB Engineering Branch report LP 187/97). Between 68 and 72 per cent of the original wall thickness of 8.7 mm had been lost due to corrosion. The TSB Engineering Branch also determined that the presence of sulphate-reducing bacteria which contributed to TCPL's decision to abandon the short section of line near the rupture site was not a factor in the 02 December 1997 line break.

The section of Line 100-3 in which the rupture occurred had been installed in 1969 in a low-lying alkaline area surrounded by pastureland. Soil conditions were a mixture of heavy clay and silt. The area tended to be wet in the spring and would dry out during the summer. A preliminary geotechnical assessment indicated that it was unlikely that slope instability or soil settlement contributed to the rupture.

Line 100-3 was coated in the field at the time of construction with asphalt enamel, felt wrap, kraft wrap and an outerwrap. The coating had been completely removed in the vicinity of the failure site either due to the initial rupture or the subsequent fire. Downstream of the rupture, the coating was in poor condition with nearly complete disbondment over the circumference of the pipe. Upstream of the rupture, the coating was in poor condition and only present on the top of the pipe. The current Canadian industry-accepted coating of choice for large-diameter cross-country pipelines is fusion bonded epoxy (FBE) which has been found to aid a pipeline's resistance to corrosion and to stress corrosion cracking.

Following the original hydrostatic test in 1969, Line 100-3 was rated for a maximum allowable operating pressure (MAOP) of 6 065 kPa. This section of Line 100-3 had not been hydrostatically re-tested since that time nor had it been internally inspected for corrosion since this section of the mainline had been assigned a lower priority from an overall corrosion susceptibility standpoint and was not equipped with in-line inspection launching or receiving facilities. During the last 10 years, there had been no repairs to the section of Line 100-3 in the vicinity of the rupture site.

In 1969, Line 100-3 was bonded to the existing cathodic protection system consisting of impressed current anodes through remote groundbeds. Since that time, discrete distributed anode beds have been installed when required. A distributed continuous anode bed was installed between MLV 5 and MLV 6 in 1996. TCPL designs its remote groundbeds for a minimum 20-year lifetime. The 20-year replacement period at 9 of the 13 groundbed locations between MLV 5 and MLV 6 had been exceeded by one to eight years. The rectifiers associated with the cathodic protection system had been in continuous operation except for outages due to pipeline construction, depolarization surveys or improvements to the existing system. Unplanned outages would be detected by TCPL during the monthly monitoring program and repairs implemented as soon as possible. Repairs could take from one to three months to complete if new components were required.

During the last 10 years of operation, close pipe-to-soil surveys were conducted by TCPL between MLV 5 and MLV 6 during the summers of 1988, 1989, 1990, 1991, 1994, 1995 and 1997. When areas of insufficient cathodic protection were detected, remedial action was recommended. TCPL will assess alternative industry criteria, which are listed in the Canadian Gas Association's Standard OCC-1, titled "Recommended Practice for the Control of External Corrosion on Buried or Submerged Metallic Structures and Piping Systems (1985)" (referred to as OCC-1). The purpose of this alternative evaluation is to determine whether effective cathodic protection actually exists. Remedial action could include groundbed replacement, installation of anode beds or an increase in rectifier output. Depending on what remedial action was recommended, it could take up to two years from the time a problem was detected to implementation. These surveys, however, did not always include the entire line. The section of pipeline in which the rupture occurred was not included during the 1988, 1990 and 1995 surveys. During the 1989, 1991 and 1997 surveys, the readings taken in the vicinity of the rupture site indicated insufficient cathodic protection levels when compared against the levels of cathodic protection that TCPL wanted to meet. While OCC-1 suggests that the cathodic protection system of a pipeline should be surveyed annually, TCPL's survey frequency of its cathodic protection system does not follow these guidelines.

TCPL conducted close pipe-to-soil surveys in the summer, under dry conditions, which according to the company, correlate to the most conservative assessment of the cathodic protection system. TCPL indicated that, as the soils are dry, the anodes produced less protective current to the pipe and therefore the cathodic protection levels were lower than at any other time of the year. According to TCPL, the decision to add new or additional facilities were made on a conservative basis. While it is true that seasonal variations affect corrosion rates and cathodic performance, the company indicated that TCPL's program of monitoring rectifier on a monthly basis ensures that the rectifiers remain energized and that adjustments are made to maintain target levels of protection to the pipe.

In 1996, TCPL had installed a new rectifier at the occurrence site and verified the effects of the installation in August 1997. However, at the time of the occurrence, no specific remedial action was indicated for that location.

Before the occurrence, the most recent line walk leak detection survey on Line 100-3 between MLV 5 and MLV 6 had been conducted in May 1996 with no leaks reported. The next line walk leak detection survey of this section is scheduled to take place during 1999, in accordance with TCPL's code of operating practice for such surveys. TCPL contracted the services of a third-party leak detection survey company in October 1996 to conduct an aerial leak detection survey of Line 100-3, between MLV 2 and MLV 41, with no leaks reported.

This section of line is patrolled by air once a week. The last patrol before the occurrence was completed during the week ending 28 November 1997 with no adverse conditions noted.

In 1994, TCPL developed a pipeline corrosion mitigation plan based on three principal strategies:

- prevention of corrosion through a combination of coatings and cathodic protection;
- pipeline integrity assessment to identify locations that require remedial action; and
- pipeline remediation to repair the line by reinforcement, re-coating, or replacement.

In 1996, TCPL began a three-year pipeline integrity program based on the corrosion mitigation plan. The program included the following items:

- the installation of cathodic protection facilities;
- in-line metal loss inspections to determine the extent and growth rates of corrosion;
- installation of launcher and receiver facilities to facilitate the in-line metal loss inspection program;
- investigative digs based on the results of the in-line inspections; and
- pipe re-coating or replacement based on the results of the in-line inspections and investigative digs.

To aid in the development of the corrosion mitigation plan, TCPL began developing a risk assessment model of the entire pipeline system. The model is to be updated as new information becomes available and, as a minimum, will be reviewed yearly. TCPL intends to use the information from the in-line inspections to refine the corrosion risk assessment model and to direct remedial work such as re-coating and pipe replacements.

Following an occurrence on the pipeline system in 1996, TCPL condensed the pipeline integrity program into a three-year accelerated program, which began in January 1997. The objective of the accelerated program was to internally inspect or internally verify all non-fusion bonded epoxy externally coated pipelines that make up the TCPL system by the end of 1999. Before the Cabri rupture, sections of the TCPL system west of Compressor Station 13 near Caron, Saskatchewan, had not been included as part of the three-year pipeline integrity program. When the accelerated program was implemented in 1996, the western section had not been considered at risk for corrosion damage.

In July 1996, TCPL began an audit of its corrosion control practices. The audit indicated that site-specific conditions were not always considered in the design of remedial action, that remedial action would be implemented based on previous experience and that, if the desired results were not realized, another type of remedial action would be taken. The audit also indicated that, because of this iterative type of process of implementing remedial action, it could take up to two years from the time a problem was detected to the time the problem was corrected.

In response to this audit, TCPL developed a program to improve its corrosion control practices by adopting the best possible site-specific remedial measures and by improving the time frame between detecting the problems and implementing remedial measures. Implementation of the program began in February and March 1998, the spring following the rupture.

The new program will involve close pipe-to-soil surveys, detailed diagnostic testing to obtain site-specific data, development of site-specific designs and implementation. The program will also include:

i) installation of coupons at selected locations to obtain information on cathodic protection levels on the bottom of the pipe;

ii) installation of coupons at selected locations to obtain data for calculation of corrosion rates of carbon steel in specific environments;

iii) geological surveys to obtain data to calculate average corrosion rates across the TCPL system;

iv) coating conductance tests to evaluate coating quality; and

v) attenuation evaluations to determine the area of influence of anodes over the pipeline.

Analysis

The extent of the corrosion on the pipe surface indicates that the pipeline coating had either been damaged or become disbonded and that the pipeline was not adequately protected by cathodic protection. Once the pipe wall thickness had been reduced by the corrosion to the extent that it could no longer support normally applied operational stress levels, the pipe failed. A metal loss in-line inspection program would have identified areas where metal loss had reached unacceptable levels.

Insufficient cathodic protection levels would have occurred during each rectifier outage or with decreasing rectifier efficiencies as would happen during periods of down-time of the cathodic protection system that arise during periods of construction, depolarization or cathodic system improvements. The presence of an abandoned section of pipeline in the immediate vicinity of the rupture site may have had a detrimental effect on the level of cathodic protection on the failed pipe. Even a brief interruption in cathodic protection would have allowed deterioration of the protective polarization film formed by cathodic protection at uncoated pipe metal. With deterioration of the film, corrosion would have occurred.

Theoretically, steel in dry, well-compacted and poorly aerated soils, such as the compacted soil found along the bottom of a pipeline, would have lower corrosion rates and require less cathodic protection current than steel in wetter soils, having a ready oxygen supply from moving groundwater. Since the soil conditions at the rupture site alternated between wet and dry, depending on the season, sections of the pipe that were poorly coated would have experienced variations in corrosion rates and the amount of current required for adequate protection. Although cathodic protection was provided, insufficient cathodic protection levels may have occurred as a result of the seasonal change in environmental conditions.

In addition, the close pipe-to-soil surveys between MLV 5 and MLV 6 were completed during the drier summer months when the soil resistivity would be higher, corrosion rates would be lower and less current would be required for adequate cathodic protection. During the wetter period of the year, soil resistivity would be lower, corrosion rates would be higher, and more current would be required for adequate cathodic protection. Therefore, the surveys may not have accurately reflected conditions on the pipeline.

Although TCPL implemented remedial action when it detected problems with its cathodic protection system, the actions taken did not always achieve the desired results since local conditions were not usually considered in determining the appropriate remedial action. Before the rupture, TCPL had begun the process of evaluating its corrosion control practices but had not begun implementation of an appropriate program to address any shortcomings. Although implementation of a program was begun during the spring following the rupture, it is still too early to evaluate its success.

Before Line 100-2 was exposed, a site survey identified that Line 100-2 had moved laterally away from the ruptured Line 100-3 pipeline. The movement of the pipeline occurred in the same general vicinity as the location of the rupture on Line 100-3. Once excavated, however, Line 100-2 was free to return to a neutral position. It could not be determined conclusively whether Line 100-2 had in fact moved either as a function of the rupture of Line 100-3, as a function of previous construction activities in the immediate vicinity on Line 100-2 and the associated back-fill operation, or as a combination of both the rupture and previous maintenance work.

Findings

1. The pipeline ruptured as a result of wall thinning due to corrosion which had occurred where the pipe coating had either been damaged or become disbonded.

2. The corrosion occurred during periods when the cathodic protection on the pipeline was insufficient according to the criteria that TCPL was trying to achieve, which would occur during periods of down-time of the cathodic protection system that arise during construction, depolarization or system improvements.

3. Seasonal variations in soil conditions would have contributed to the rate of corrosion and the amount of current required for adequate cathodic protection.

4. The annual close pipe-to-soil surveys, usually completed during the summer months when soil conditions were drier, may not have accurately reflected seasonal variations of soil conditions on the pipeline.

5. TCPL's corrosion control practices did not always rectify the problem of insufficient cathodic protection according to TCPL's criteria on its pipeline since local soil conditions were not usually considered in the design and implementation of remedial action.

6. An in-line metal loss tool had not been run in this valve section since this section of the mainline had been assigned a lower priority from an overall corrosion susceptibility standpoint and this section was not equipped with launching or receiving facilities.

7. The TCPL system west of Caron had not been included in TCPL's three-year pipeline integrity program developed in 1996.

Causes and Contributing Factors

The pipeline ruptured as a result of localized wall thinning due to external corrosion. The corrosion occurred where the pipe coating had either been damaged or become disbonded. The corrosion occurred during periods when the cathodic protection at the rupture location was insufficient.

Safety Action Taken

Beginning in January 1997, TCPL proceeded with its three-year accelerated pipeline integrity program. The objective of the 1997 program was to internally inspect all non-fusion bonded epoxy coated pipelines on the TCPL system by the end of 1999. In keeping with this objective, approximately 3000 kilometres of the TCPL system was internally inspected in 1997, using both temporary and permanent launching and receiving facilities, which are utilized to insert and extract in-line inspection devices. Following the Cabri occurrence, TCPL revisited the accelerated in-line inspection program. As a result, TCPL has further accelerated the in-line inspection program for sections west of MLV 41. Specifically, TCPL advises that Lines 100-1, 100-2, 100-3 and 100-4, between MLV 2 and MLV 9, were all inspected by March 1998. In some cases, TCPL has facilitated the in-line inspection of sections of its system by utilizing temporary launchers and receivers, because permanent facilities would not have been available for installation for approximately six months. TCPL has included the inspection of those remaining portions of Line 100-1 between MLV 2 and MLV 41 which had been originally scheduled for completion of in-line inspection in 1999. By the end of 1998, TCPL had completed the integrity verification of all mainline sections on Lines 100-1, 100-2, 100-3 and 100-4 between MLV 2 and MLV 41.

TCPL is continuing with the program to improve its corrosion control practices, as outlined above, which it began implementing in March 1998 following the rupture.

TCPL is in the process of expanding its public awareness program to include not only immediate landowners but also neighbouring landowners, the general public, regulators, provincial and federal officials, municipal and community leaders and the media. It has also prepared new public awareness literature and added a pamphlet on personal safety which addresses what the public can do if faced with a pipeline emergency.

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 24 March 1999.