Transportation Safety Board of Canada
Bureau de la sécurité des transports du Canada

TRANSPORTATION SAFETY

REFLEXIONS

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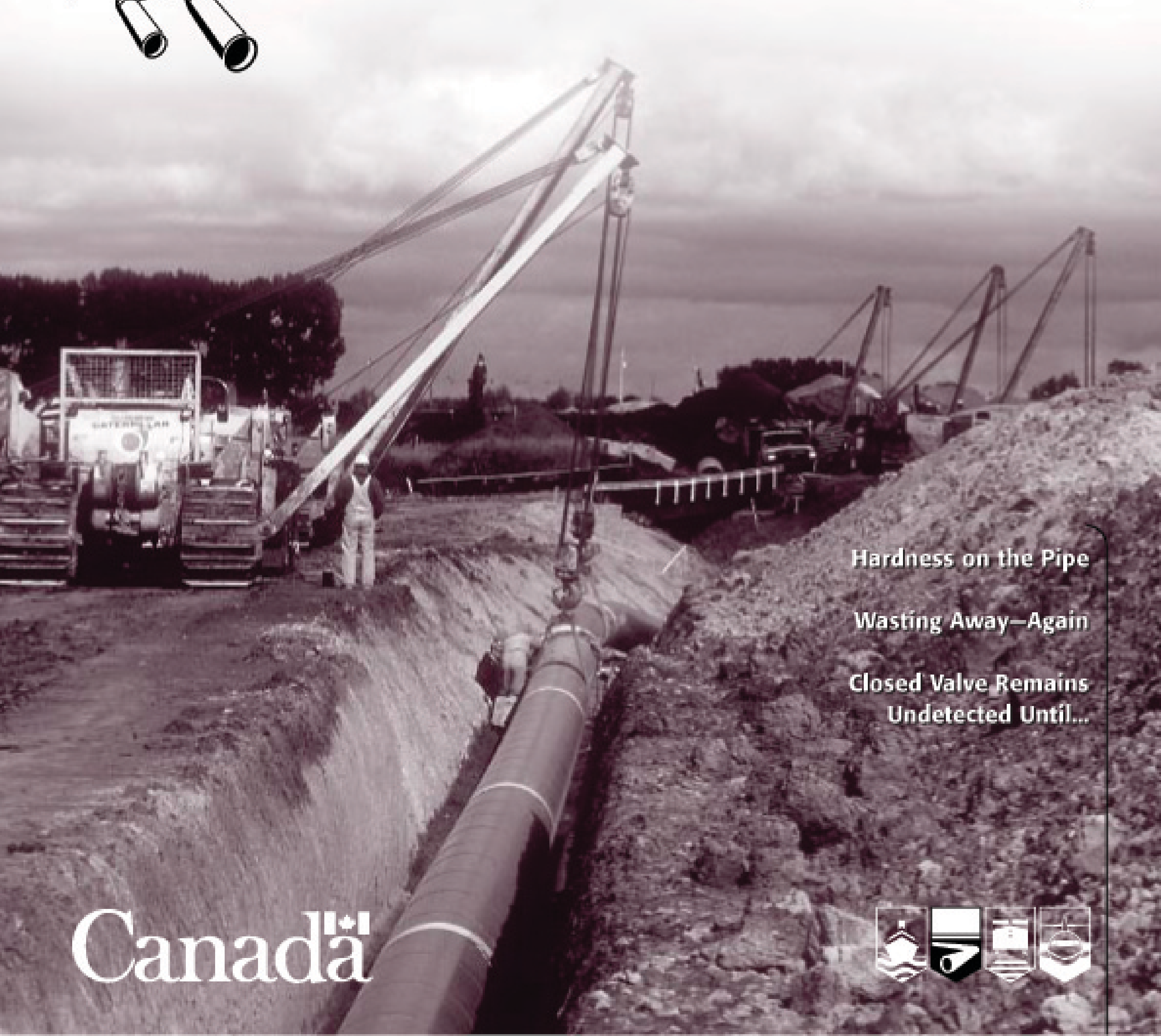
PIPELINE

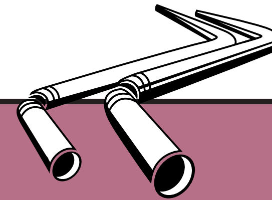


Hardness on the Pipe

Wasting Away—Again

Closed Valve Remains Undetected Until...

Canada



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Downstream end of rupture.

Hardness on the Pipe

On 07 August 2000, a rupture occurred on the Westcoast Energy Inc. (Westcoast) mainline at a localized area of higher hardness, a hard spot, on the exterior surface of the pipe. The hard spot probably resulted from inadvertent quenching during the manufacturing process. The rupture occurred approximately 9 km south of the Coquihalla Highway toll booth (toll booth) and almost midway between Westcoast's Compressor Stations 8A and 8B. — Report No. P00H0037

Response to the Rupture

The rupture generated a rate of pressure change of under 207 kilopascals (kPa) per minute and was recorded at Compressor Station 8B by the Supervisory Control and Data Acquisition (SCADA) system as an event. Rates of pressure change of less than 207 kPa per minute can occur during normal operating conditions and are therefore recorded by the SCADA system as an event. Unless such changes are part of a sequence of alarms, they do not normally indicate a line break situation. When the gas controller became aware of the event message, he began to investigate the reason for it.

At the same time that the gas controller was beginning his investigation, the toll booth clerk became aware that there had been an explosion near the Zopkios rest stop. The toll booth clerk decided to stop all southbound traffic at the toll booth and alerted the Royal Canadian Mounted Police (RCMP) detachment in Hope, British Columbia. In addition

Westcoast's line break detection system had not been configured to signal a rupture based on changes in flow rate.

to information received through the SCADA system, notification from an outside source can often confirm that a rupture has occurred to the gas controller. However, personnel at the toll booth did not have sufficient knowledge about Westcoast's pipeline system and its proximity to the Coquihalla Highway to enable them to notify the gas controller as soon as they became aware of the explosion near the rest stop.

Although a rupture should have resulted in a rate of pressure change equal to or greater than 207 kPa per minute, the rate of pressure change at Compressor Station 8B never reached this alarm situation. This was probably due to a combination of the pipeline configuration between Compressor Stations 8A and B, spare horsepower at Compressor Station 8A, Compressor Station 8B being bypassed, and the location of the rupture. The first two factors probably created a large flow reversal on the mainline at Compressor Station 8B and a large flow increase on the mainline loop. At the time of the rupture, Westcoast's line break detection system had not been configured to signal a rupture based on changes in flow rate. The line break detection system was however configured to detect a rupture based on a rapid rate of pressure change or low pressure, neither of which occurred at the time of the rupture.

Previous Occurrence

About four years before this rupture, a leak had initiated at another location on the mainline in a hard spot created during the original pipe manufacture. Following this 1996 occurrence, Westcoast conducted an in-line inspection for hard spots of the mainline between Compressor Station 9 and Huntingdon, British Columbia. Five locations were identified, excavated and inspected for abnormal hardness and cracking. Neither abnormal hardness nor cracking were detected at any of those locations. No other sections of the mainline had been internally inspected for hard spots before the rupture in August 2000. Although Westcoast had an in-line inspection program for the mainline, the program was designed to detect metal loss and not hard spot anomalies.

Action Taken

Among the actions that Westcoast took subsequent to the August 2000 rupture were

- completion of in-line inspections for hard spots of the sections of the mainline;
- aerial patrol of the mainline and the mainline loop sections using infrared imaging technology to determine leaks;
- revision of line break procedures to assist in diagnosing line break situations;
- presentations to the personnel at the toll booth concerning its pipeline system; and
- upgrading of the SCADA system so that the audible annunciation feature for high-priority alarms cannot be disabled.

In addition, Westcoast intended to proceed with

- completion of in-line inspections for hard spots of the remaining three sections of its mainline containing pipe manufactured by A.O. Smith Corporation;
- creation of site-specific line break procedures for use in the Gas Control Centre and at each station; and
- improvement of line break detection methods by using gas flow rate changes.

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An in-line inspection program is only as effective as the tool that is used.

Escaping gas ignited.

Wasting Away—Again

Following two previous ruptures on the TransCanada PipeLines Limited (TCPL) system (TSB reports P94H0036 and P94H0049), TCPL developed a pipeline corrosion mitigation plan and in 1996 began a three-year pipeline integrity program based on that 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 launching and receiving facilities to help in 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.

However, a rupture occurred at an area of external corrosion on TCPL Line 100-1 near Stewart Lake, Ontario, on 11 December 1996. Up to 76 per cent of the original wall thickness had been lost to corrosion. This section of Line 100-1 was to have been part of the internal inspection program for 1997.
— Report No. P96H0049

The pipeline was not adequately protected by cathodic protection.

During the isolation of Station 52, the station upstream of the rupture, several problems were apparent: there were no independent back-up SCADA communications at Station 52, the trigger valves which would have actuated the closure of main line valves (MLVs) 52-2 and 52-3 on low pressure did not operate due to frozen moisture in their pressure sensing lines, and MLV 52-1 did not seal completely. Therefore, following the rupture, TCPL replaced MLV 52-1, installed diverse channels to provide independent back-up SCADA communications at Station 52, and revised its valve operator maintenance procedures to prevent moisture problems from occurring. In addition, it further improved its emergency response procedures by installing remote-control and pressure-monitoring capability at end-of-loop termini and other critical locations, conducting emergency response planning sessions with first response agencies and enhancing its public communications.

The extent of the corrosion on the pipe surface indicated that the pipeline coating had either worn away or become disbonded and that the pipeline was not adequately protected by cathodic protection. The bedrock on which the pipe was lying does not conduct current and may have shielded or partially shielded the pipe from cathodic protection.

As a result of concerns expressed by attendees at an open house in Vermillion Bay, Ontario, hosted by TCPL following the rupture, TCPL committed to

- installing heavy wall pipe on Line 100-1 within the limits of the town of Vermillion Bay;
- accelerating the in-line inspection program on Line 100-1 between MLV sections 52 and 58; and
- reducing the maximum allowable operating pressure (MAOP) on Line 100-1 to 95 per cent of authorized MAOP between MLV sections 51 through 55 until in-line inspections and required pipe replacements have been completed.

In addition, 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.

Subsequent to the December 1996 rupture, on 02 December 1997, the TCPL pipeline system experienced another rupture at an area of external corrosion, this time on Line 100-3 near Cabri, Saskatchewan. The pipeline ruptured as a result of localized wall thinning due to external corrosion which had occurred where the pipe coating had either been damaged or become disbonded. Between 68 and 72 per cent of the original wall thickness had been lost due to corrosion.
— Report No. P97H0063

When the pipeline integrity program was implemented in 1996, sections of the TCPL system west of Compressor Station 13 had not been considered at risk for corrosion damage and had not been included in this integrity program. An in-line metal loss tool had therefore 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.

TCPL's annual close pipe-to-soil surveys might not have accurately reflected seasonal variations of soil conditions on the pipeline.

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

TCPL's annual close pipe-to-soil surveys, usually completed during the summer months when soil conditions were drier, might not have accurately reflected seasonal variations of soil conditions on the pipeline. Moreover, 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.

Following the Cabri occurrence, TCPL revisited its accelerated in-line inspection program. As a result, TCPL further accelerated the in-line inspection program for sections west of MLV 41. In addition, in the spring of 1998, TCPL began implementing 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. The new program will involve close pipe-to-soil surveys, detailed diagnostic testing to obtain site-specific data and development of site-specific designs and implementation.

REFLEXION

Sometimes the problems that you think are under control can resurface.

Ruptured pipe on Line 100-3 near Cabri, Saskatchewan.

Closed Valve Remains Undetected Until . . .

The Westcoast Energy Inc. (Westcoast) Kobes Creek pipeline in northern British Columbia ruptured at Mile Post (MP) 10.72 on 08 December 1998, following a continued build-up of internal wet, sour natural gas pressure above the authorized maximum allowable operating pressure (MAOP).
— Report No. P98H0044

The Pigging Operation

In the afternoon of December 8, Westcoast operations personnel launched an internal cleaning device (cleaning pig) from a launching barrel at MP 0.0 on the Kobes Creek pipeline to a receiving barrel at MP 18.88 at the Kobes compressor station. Following the pigging operation, station personnel began resetting valves to their normal gas flow position. Although one of the valves, motor-operated valve (MOV) 0410, was confirmed by the Supervisory Control and Data Acquisition (SCADA) system at the Fort St. John Gas Control Centre (FSJGCC) to be in the open position, the position for normal gas flow, the valve received an unsolicited closure command several minutes later and began to close. The FSJGCC and Kobes station personnel were not aware of the change in status of the valve from the fully open position to the fully closed position.

Westcoast required pressure protection equipment to be located on all pipelines tied into the Westcoast pipeline system.

The Pipeline

The Kobes Creek pipeline was 30.38 km (18.87 miles) long and was used exclusively to transport raw, wet, sour natural gas on behalf of the shippers from seven different receipt points (RPs) to the Kobes compressor station at MP 18.88. At MP 0.0, four receipt point operator (RPO) facilities were tied into the pipeline system with a normal receipt pressure at point of entry into the Kobes Creek pipeline of 4 862.5 kilopascals (kPa) (700 pounds per square inch gauge [psig]). RP 2612 was tied into the pipeline at MP 0.0 on 26 October 1998 and was the most recent RP delivery tie-in. Pressure at the production end of the pipeline bringing gas into RP 2612 was normally at 8 274 kPa (1 200 psig). Delivery pressure from this pipeline into the Kobes Creek pipeline was higher than the delivery pressure from the pipelines feeding the other three RPs at MP 0.0.

As a contractual condition of transporting gas on its pipelines, Westcoast required pressure protection equipment to be located on all pipelines tied into the Westcoast pipeline system that are connected to a natural gas production source operating or producing at a higher pressure than the MAOP of the respective Westcoast pipeline. However, before the commencement of service at MP 0.0 by RP 2612, overpressure protection equipment was not installed. In addition, although Westcoast had formal procedures to physically inspect the RPO facilities to ensure compliance with its requirements, Westcoast did not follow those procedures regarding the RPO facilities at RP 2612.

Supervisory Control and Data Acquisition (SCADA)

As part of the normal operating procedures on the Westcoast gathering system, a comprehensive and sophisticated SCADA system was installed. The SCADA system provides a necessary link between all pipeline facilities, valves and equipment to the various local gas control centres, such as the FSJGCC and the main Vancouver Gas Control Centre (VGCC). The VGCC is able to oversee Westcoast's complete operating pipeline facilities. At MOV 0410, there were three pressure transmitters feeding signals into the SCADA system—one transmitter on either side of MOV 0410 and one transmitter located on the alternative station suction loop line. The calibration of the three pressure transmitters was set to a maximum pressure reading of 6 895 kPa (1 000 psig) and did not provide actual pressure readings greater than that. At MP 0.0, a pressure gauge was installed, but the readings could only be obtained locally and visually. The pressure gauge at MP 0.0 was not capable of providing actual pressure readings directly to the SCADA system.

The Overpressure Situation

Following the pigging operation, since MOV 0410 had had an unsolicited closure and had returned to the fully closed position, pressure in the pipeline continued to increase on the upstream side of this valve. As pressure continued to increase, natural gas production from the pipeline behind RP 2612 continued to flow into the Kobes Creek pipeline. Since delivery pressure at RP 2612 was higher than the delivery pressure at the other three RPs at MP 0.0, all natural gas flow from the three RPs ceased. When the Kobes Creek pipeline reached its MAOP, only RP 2612 was moving natural gas, which continued to flow until the pipeline ruptured.

SCADA Alarms

Approximately 20 minutes after station personnel had confirmed with the FSJGCC that MOV 0410 was in the normal open position, the FSJGCC received a SCADA-generated high-level pressure alarm indicating pressures in the pipeline of 4 606 kPa (668 psig) upstream of MOV 0410. Normal pressures upstream of MOV 0410 are usually in the range of 4 137 to 4 482 kPa (600 to 650 psig). The FSJGCC personnel however did not initiate immediate corrective action. Approximately 2 1/2 hours later, at 2010, the FSJGCC received another SCADA-generated alarm, this one indicating pressures greater than 6 895 kPa (1 000 psig) upstream of MOV 0410. The FSJGCC contacted the VGCC to verify the overpressure range reading in the pipeline. Once confirmed by the VGCC, the FSJGCC notified the Kobes off-shift station operator of the overpressure in the pipeline. The station operator proceeded to the compressor station and found an indication of a leak in the station scrubber building. In view of the extreme health risks associated with an H_2S leak, the station operator advised the FSJGCC that the first priority was to investigate the H_2S leak and to complete any repairs deemed necessary to stop the release of H_2S before investigating the overpressure situation on the pipeline.

The station operator initiated a First Order Shutdown, which effectively shut down everything at the compressor station.

At 2055, the FSJGCC was advised that the H_2S leak had been located on the flange connection on the downstream side of a safety relief valve located on a fuel scrubber vessel. Five minutes later, the station operator initiated a First Order Shutdown, which effectively shut down everything at the compressor station. At approximately the same time, the FSJGCC and the Kobes station control panel lost communication abilities with MOV 0410 resulting in the SCADA system being unable to update the status of pressure readings in the pipeline. The back-up system to ensure communication did not function due to a defective battery cell.

The Rupture

Between 2200 and 2230, the pipeline ruptured due to overstress brought on by a continued build-up of internal pressure above the authorized MAOP. At that time, Westcoast personnel were not aware of the rupture because of the loss of communications at the station at 2100. At approximately 2230, however, FSJGCC was advised on two occasions of a fire in the general vicinity of the Kobes Creek pipeline right-of-way but did not take appropriate action to initiate Westcoast's emergency response plan.

The rupture was confirmed at 0005 on 09 December 1998 when a second pressure gauge was manually installed upstream of MOV 0410 which indicated that the internal pressure in the pipeline was 0 kPa. Producers were then requested to shut in production.

Action Taken

Actions taken by Westcoast in response to this occurrence regarding overpressure protection include: inspections of new RPs to ensure that overpressure protection equipment has been installed and is functioning correctly; audits of existing RPs to determine which require overpressure protection and if the proper protection is in place and functions correctly; and a program to address future audits of RP overpressure protection.

Other changes made by Westcoast include: changes to its SCADA system for the Fort St. John gathering system; changes to emergency response procedures, in particular with respect to emergency planning zones; and changes to gas control training and emergency response training.

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An occurrence rarely results from one event. How many opportunities were there to avoid or alleviate the continuous build-up of pressure?

TCPL Compressor Station 30.

Emergency Shut-Down Woes

As a result of its investigation into the rupture and fire on two natural gas pipelines near Rapid City, Manitoba, the TSB identified deficiencies involving the emergency shut-down of these pipelines. The Board made two safety recommendations to address these deficiencies and expressed concern about the horizontal spacing between adjacent pipelines.

A rupture and fire occurred on TCPL's Line 100-4 on 29 July 1995, at a TransCanada PipeLines Limited (TCPL) compressor station about 3 km southeast of Rapid City. The rupture occurred as a result of a pre-existing stress corrosion crack (SCC) in a piece of pipe downstream of the compressor station. This piece of pipe had been fabricated in the field and coated with polyethylene tape.

The resulting explosion and fire destroyed much of the communications system at the compressor station and made it difficult to shut off the flow of gas in Line 100-4. As a result, TCPL's Line 100-3, adjacent to Line 100-4, sustained fire damage that weakened it, and it too ruptured and caught fire. TCPL's Line 100-5 which passed under Lines 100-3 and 100-4 sustained minor fire damage to the coating of the pipe.
— Report No. P95H0036

Emergency shut-down systems should be capable of automatically isolating flow of product to an accident site.

Problems with the Emergency Shut-Down System

The TSB investigation also discovered a problem with the Supervisory Control and Data Acquisition (SCADA) system. This fault in the SCADA system delayed the shut-down and isolation of Lines 100-4 and 100-3. While the Winnipeg Regional Operations Controller (ROC) reacted immediately to the simultaneous indications of a loss in pressure and a pipeline rupture, he tried numerous times over a two-hour period to initiate a computer-initiated emergency shut-down (ESD) command to the Rapid City compressor station, which would have isolated the flow of natural gas to the occurrence site. He was restricted from successfully carrying out this computer command due to the effects of the explosion and fire on the local ESD equipment used to carry out these computer commands and SCADA system programming errors. Furthermore, the ROC had to re-issue "close" commands every 15 minutes because the SCADA system did not have the capability during an ESD to override the 15-minute feature of the "close" command. While the subsequent investigation was ongoing, TCPL advised the TSB that the faults in the ESD and isolate commands had been corrected.

Even though considerable action had been taken, the TSB was concerned that the ROC was unable to effect a rapid shutdown of the system. This inability to shut down the system led to considerable collateral damage in and around the compressor station and to the rupture of Line 100-3.

The Board believed that ESD systems should be hardened against explosive forces and fires, and should be capable of automatically isolating flow of product to an accident site, overriding other commands if necessary, until it has been verified that it is safe to reactivate normal operations. To that end, in its final report on the investigation into this accident, the Board recommended that:

The National Energy Board reassess the design provisions for "emergency shut-down" anywhere in the pipeline system with a view to ensuring the rapid isolation from the flow of product in the event of a ruptured line.
P97-01

In addition to the problem with the remote ESD, there also was a problem with the on-site ESD. The TSB understands that compressor stations are often unstaffed. Nevertheless, as a backup to the remote system defences for ESD, company employees should be capable of ensuring an ESD locally. In addition to ESD equipment and training, there should be a feedback loop so that employees can determine if the shut-down has been initiated. The Board therefore also recommended that, as a part of the design review of recommendation P97-01:

The National Energy Board reassess the adequacy of the emergency shut-down systems at compressor stations, with a view to ensuring that operators are aware of the operating status of the system under emergency conditions.
P97-02

In its response to these recommendations, the National Energy Board (NEB), the pipeline regulator, indicated agreement with the intent of both recommendations, and forwarded information requests to the regulated pipeline companies in order to gain a more detailed understanding of the factors pertinent to the issues raised by the recommendations.

Current spacing standards may be inadequate, particularly in highly populated areas.

Horizontal Spacing of Pipelines

As a result of its investigation, the Board noted that there are currently Canadian Standards Association requirements for vertical spacing between pipeline systems in Canada; these requirements address the safety issues associated with pipeline systems that cross over each other. However, there are no similar requirements for the horizontal spacing of pipeline systems. The Board was concerned that current spacing standards may be inadequate in this regard, especially considering the potential consequences of a natural gas pipeline failure, particularly in highly populated areas.

With respect to this safety concern, the NEB was of the view that, compared to other factors, horizontal spacing between parallel pipelines historically has not been a significant factor in collateral safety of pipelines. The NEB listed the conditions that should be considered when imposing standards on horizontal spacing of pipeline systems:

- It is desirable, especially in environmentally sensitive areas, to have a right-of-way as reasonably narrow as possible.
- An increased horizontal spacing may increase potential third-party encroachment and damage.

Ruptured Lines 100-3 and 100-4.

- It is difficult to maintain a pre-set horizontal spacing between pipelines near or within compressor stations, in congested areas such as towns and cities, or in areas such as river crossings.

The NEB's ongoing design review program should be sufficient to monitor appropriate future pipeline spacing requirements.

Action Taken

Following the rupture near Rapid City, TCPL expanded its SCC management program, consisting of hydrostatic re-testing, soils modeling to assist in determining potential SCC locations, investigative digs, and pipe replacement. Also, shortly following the accident, the NEB ordered a public inquiry into SCC occurrences on Canadian oil and gas pipelines. The report, released to the public on 19 December 1996, contained 27 recommendations to promote public safety on buried oil and gas pipelines in Canada.

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The faster that a system can be shut down, the lower the risk of collateral damage.

Fragment landing site with La Salle River in the background.

River Crossing Instability

Most pipeline companies perform regular aerial surveillance of their pipeline systems to observe conditions which might affect pipeline safety and operations. However, certain types of geotechnical events may require specialized monitoring techniques over and above aerial patrols.

A rupture, followed by an explosion and fire, occurred on the TransCanada PipeLines Limited (TPCL) Line 100-2 crossing of the La Salle River, 10 km southwest of Winnipeg, near the town of St. Norbert, Manitoba, on 15 April 1996. The pipeline ruptured due to high external stresses on the surface of the pipeline resulting from the movement of the slope in which the pipe was buried. The rupture initiated at a major pre-existing defect in the toe of the circumferential weld. — Report No. P96H0012

Response to the Rupture

Within minutes of the rupture, the Winnipeg Emergency Centre (911) was advised of the situation at the La Salle River by a local resident. Approximately 14 minutes following the rupture, a local resident called the TCPL 24-hour emergency phone number providing first notification to TCPL of the pipeline break. At this time, the escaping natural gas ignited cutting power and phone services to the area surrounding the occurrence site.

Twenty minutes after the rupture, TCPL's Calgary Gas Controller (Calgary Controller) was advised of the occurrence by the Winnipeg Regional Operations Controller (ROC). However, several minutes later, the Calgary Controller advised the ROC that the Calgary Gas Control Centre (Calgary Centre) was unable to detect the occurrence because of a telemetry outage at TCPL's Compressor Station 41, downstream of the rupture. The outage was unrelated to the rupture. While the ROC had direct telemetry

The company was not immediately notified of the occurrence.

communication with Station 41 and was receiving Supervisory Control and Data Acquisition (SCADA) data, the Calgary Centre was not. The Calgary Controller had to communicate all instructions verbally to the ROC who in turn executed the instructions.

Thirty minutes after the first notification to 911 of an occurrence, the Calgary Controller instructed the ROC to isolate Lines 100-1 and 100-2 between Station 34, upstream of the rupture, and Station 41.

Emergency Notification

Although TCPL is a member of the Winnipeg Disaster Response Plan, when the Winnipeg Emergency Centre first received news of the occurrence, the company was not immediately notified. TCPL only became aware of the events at the crossing when advised by a member of the general public and by a TCPL employee who happened to observe a live report on a local television station.

TCPL's Emergency Shut-Down Procedure

In accordance with the company's Emergency Procedure Manual and upon verification of a pipeline break or an emergency situation affecting the security of the pipeline system, TCPL's procedures call for the immediate isolation by the ROC of all pipelines between compressor stations, either side of the occurrence site. During this occurrence, and in a deviation from company isolation procedures, not all sections of the pipelines between stations were isolated. In this case, sufficient information was available to the decision makers so that the departure from established procedures should be considered acceptable.

Pipeline Particulars

At the occurrence site, TCPL has six parallel lines of pipe buried at depths of between 1.5 m and 4.0 m in soils which exhibit slow to moderately slow permeability. Although the failure of Line 100-2 did not cause any damage to the other lines, Line 100-1 was replaced since it passed through the same area of slope instability and movement as Line 100-2. Since a section of the Line 100-3 river crossing adjacent to the Line 100-2 rupture was found to have shifted, Line 100-3 was daylighted and stress-relieved by allowing the pipeline to return to a neutral position. There was no evidence of surface damage on Line 100-3 after the stress-relieving activities.

The ruptured section of Line 100-2 had an outside diameter of 864 mm, nominal wall thickness of 12.7 mm and a specified minimum yield strength of 359 megapascals. The pipe was manufactured in 1962 by A.O. Smith Corporation with a "flash butt" welded longitudinal seam weld. This section of Line 100-2 was constructed in 1962 and was externally coated at that time with an outer wrap comprising three layers wrapped over a wet-applied mastic to form a laminar cold-applied electrically insulative and mechanically reinforced coating system. As a means of providing buoyancy control, the original design called for the installation of nine bolt-on, 34-inch concrete river weights, each weighing 2 800 kilograms (6 200 pounds).

The Failure

The rupture initiated at a major pre-existing defect in the toe of the circumferential weld. It is possible that the initial crack was there from the time of the original construction in 1962. The main loading force leading to the failure came from pipe bending caused by the movement of the slope in which the pipe was buried.

The River Slope

A geotechnical examination of the crossing following the rupture found an area of pre-existing slope instability, through which the failed pipeline was constructed. The slope was found to be moving downward during periods of seasonally high river levels. These episodes of slope movement resulted in incremental, monotonic loading of Line 100-2 which could have been predicted to result in bending stresses in the pipe at the rupture site.

The area surrounding TCPL's La Salle River crossing has had a history of slope failures and previous construction activity

Previous construction activity on the east bank of the La Salle River had revealed the instability of the river crossing.

on the east bank of the La Salle River had revealed the instability of the river crossing. During the installation of Line 100-4, a significant slump occurred when the Line 100-4 trench wall failed, exposing Line 100-3. During the installation of Line 100-5 in 1991, excavated soil was stockpiled temporarily on the slope over Line 100-2. Ground movement was observed beneath this stockpile. There was no record before the failure that there had been any follow-up excavations, checks or pipe surface inspections of any of the six pipelines to address the issue of ground movement at the crossing.

Monitoring of the Pipeline Route

The National Energy Board (NEB) regulations entitled *Onshore Pipeline Regulations* (SOR/DORS/89-303) (OPR) require that monitoring and surveillance programs of the pipeline system form an integral part of the company's operating and maintenance manuals. While TCPL performs regular aerial surveillance of its pipeline system in order to satisfy the requirements of the OPR, and while the pilots for TCPL had been instructed on the detection of soil instability, soil subsidence and signs of soil siltation, the pilot carrying out the aerial surveillance had not been trained to identify unusual geotechnical events (such as occurred at the La Salle River pipeline crossing) that would be indicative of slope movement. In any event, while aerial surveillance would have identified a catastrophic slope failure, it would not have detected this type of slope movement. The investigation found that, while the NEB had communicated with all federally regulated pipeline companies on 26 November 1993, indicating that the NEB regulatory requirements for monitoring and surveillance programs included the monitoring of slopes susceptible to failure or movement, TCPL had not installed any equipment at the La Salle River crossing to monitor slope movement.

Action Taken

TCPL modified the scope and depth of its operating practices and procedures, as follows:

- The SCADA telemetry connection has been modified to re-establish communications with a compressor station in the event of a loss of primary telemetry signal.
- The emergency procedure manual has been rewritten to permit deviation from the established "total shutdown" procedures.
- Procedures have been amended to allow for faster notification of its management teams.
- A long-term program has been established to ensure the success of the site stabilization and monitoring instituted for the La Salle River crossing.
- A system-wide geotechnical program will examine the pipeline rights-of-way for evidence of slope movement, and will assemble a database of soil types, pipe coatings and geotechnical and geographical features for all river crossings on the system.

Second fragment retrieved from river bottom.

TCPL's emergency procedure manual, which contains the emergency response plan, has been modified such that TCPL's ROCs across the TCPL system will immediately initiate the regional call-out procedure upon suspicion of a pipeline emergency. Furthermore, as part of a company-wide initiative, TCPL's regional offices have held emergency response planning sessions with each fire department along the complete TCPL system. The emergency response planning sessions included a discussion regarding communications, coordination and the need for continuous site security at occurrence sites.

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The benefits of installing instrumentation to detect slope movement may far outweigh the cost.

Pipeline Occurrence Statistics

	2001	2000	1996–2000 Average
Accidents			
Line Pipe	**10**	**6**	**8**
Third-party Damage with Release	1	0	0
Disturbance of Supporting Environment with Release	1	0	1
Corrosion / Environmental Cracking	1	0	3
Fire/Ignition/Explosion	2	1	1
Other Damage with Release	5	5	3
Other Facilities*	**13**	**16**	**13**
Third-party Damage	1	0	0
Disturbance of Supporting Environment with Release	0	0	0
Corrosion / Environmental Cracking	2	0	2
Fire/Ignition/Explosion	7	7	5
Other Damage with Release	3	9	6
Incidents			
Line Pipe	**7**	**11**	**8**
Third-party Damage / No Release	2	2	1
Disturbance of Supporting Environment / No Release	0	0	0
Uncontained Release	4	7	6
Other	1	2	1
Other Facilities*	**27**	**26**	**26**
Third-party Damage / No Release	0	0	0
Disturbance of Supporting Environment / No Release	0	0	0
Uncontained Release	24	25	24
Other	3	1	2

* Includes compressor stations, pump stations, meter stations, gas processing plants, and other related facilities.
Figures are preliminary as of 14 January 2002.

PIPELINE Occurrence *Summaries*

The following summaries highlight pertinent safety information from TSB reports on these investigations.

COSTLY DELAYS

A nipple on an unburied tapping connection at Mile Post 23.5 on the Trans-Northern Pipelines Inc. (TNPI) Ottawa Lateral failed on 10 February 1997 due to the presence of a substantial ice load bearing down on the connection. — Report No. P97H0007

As part of the company's ongoing integrity program, the lateral had previously been internally inspected for defects and anomalies. During June 1996, the occurrence site was identified as requiring investigation to calibrate an anomaly indicated on the internal inspection log. Following excavation, a sleeve was installed over the pipeline to provide reinforcement over an anomaly in the weld seam. While TNPI could have backfilled the repaired pipeline at this point, the company elected to schedule removal of the pipeline segment to better understand the nature of the defect through a metallurgical examination. In preparation for the removal of the pipe section, two tapping connections were installed on the pipeline to facilitate drain down of product from the pipeline for maintenance purposes. Because of scheduling delays, the two unburied tapping connections were left in place for a period of eight months as compared with the normal 24 to 48 hours for similar situations.

Tapping connection.

During that period, the excavation filled with water, ice and snow, and the threaded connections could be viewed as becoming a buried structure at the bottom of the opening. Although periodic inspections of the open ditch were completed by TNPI, TNPI personnel did not ensure that there were no situations developing in or around the exposed pipeline that could threaten the safety of the system. TNPI personnel were not issued with specific instructions regarding the company's concerns with respect to the exposed pipe in the open ditch. During the eight-month period that the pipeline was exposed, TNPI personnel had performed 32 vehicle inspections together with weekly overflights of the occurrence area. However, the identification of the potential hazard of ice accretion and snow cover in the bottom of the ditch was not addressed.

Failed nipple.

The substantial ice load pressing down on the two tapping connections led to the nipple failure. The nipple was made of plain carbon steel of relatively low strength with a large ferrite-pearlite grain microstructure, both conducive to a brittle-type failure under overload in cold weather conditions. Contributing to the occurrence was the fact that inspection personnel were not given specific instructions on what to monitor and the action to be taken.

REFLEXION

An inspection is only as good as the instructions that have preceded it.

SUDDEN SLOPE MOVEMENT

A rupture occurred near Fort St. John, British Columbia, on 30 April 1997, on the Westcoast Energy Inc. (Westcoast) Monias pipeline at a buckle which had formed in the pipeline due to the longitudinal compression caused by pipe-to-soil interaction created by the sudden rapid movement of an existing slide block. The Monias receiving line break valve, the only low-pressure shut-off valve on the Monias pipeline, closed automatically as intended. However, the tie-in valve and the block valve needed to complete isolation of the rupture site from the producers' facilities had to be closed manually. Isolation of the rupture site took more than one hour from the time the rupture was first identified. — Report No. P97H0024

Location of the Pipeline

The Monias pipeline crossed the Peace River 1 km downstream of the Old Fort St. John area. After the crossing, the pipeline turned west and followed the toe of the north slope of the river valley for about 0.5 km. At this point the pipeline turned and ran diagonally in a northeasterly direction to the crest of the slope. On 30 April 1997, this portion of the north valley slope underwent a movement of at least 7 m laterally.

The Slope Failure

A geotechnical assessment of the area following the failure indicated that the block that failed was part of a larger deep-seated pre-existing complex which may have been undergoing slow, small-scale creep movements. The block that failed however had had no significant movement in the history of the pipeline.

The reactivation of the slide block within the larger pre-existing landslide complex was probably due to high ground water levels which had resulted from high precipitation levels over a three-year period and high snow pack combined with minimal ground frost. Slightly increased slope movements may have opened up existing tension cracks which then filled with water. Since the surficial clays in this area tend to be self-healing, the tension cracks would have probably closed up trapping the excess water as well as preventing observation of the crack. The trapped water would have caused increased pressures, triggering additional rapid movement.

Westcoast's geotechnical monitoring program for the Monias pipeline, which had included an aerial patrol the day before the rupture, could not have provided advance warning for this type of sudden rapid slope movement.

Action Taken

Subsequent to this occurrence, regarding the Monias pipeline, Westcoast installed slope indicators at the crest and the toe of the slope and midway through the slide area, and three low-pressure shut-off valves in the vicinity of the Peace River crossing to limit plume size at the Old Fort St. John area in the event of a pipeline rupture.

In addition, with respect to its geotechnical monitoring program, Westcoast increased aerial monitoring of known slide areas and installed geotechnical monitoring instrumentation at certain new locations and additional instrumentation at other existing locations.

Investigations

The following is *preliminary* information on all occurrences investigated by the TSB that were reported between 01 November 1996 and 28 February 2002. Final determination of events is subject to the TSB's full investigation of these occurrences.

DATE	COMPANY	LOCATION	EVENT	OCCURRENCE NO.
DECEMBER 1996 11	TransCanada PipeLines Ltd.	Stewart Lake, Ont.	Natural gas pipeline rupture	P96H0049
FEBRUARY 1997 10	Trans-Northern Pipelines Inc.	Vernon, Ont.	Products pipeline material release	P97H0007
APRIL 30	Westcoast Energy Inc.	Fort St. John, B.C.	Natural gas pipeline rupture	P97H0024
DECEMBER 02	TransCanada PipeLines Ltd.	Cabri, Sask.	Natural gas pipeline rupture	P97H0063
DECEMBER 1998 08	Westcoast Energy Inc.	Kobes Creek, B.C.	Wet sour natural gas pipeline rupture	P98H0044
MAY 1999 20	Enbridge Pipelines Inc. (formerly IPL)	Regina, Sask.	Crude oil pipeline rupture	P99H0021
AUGUST 2000 07	Westcoast Energy Inc.	Coquihalla Highway, B.C.	Natural gas pipeline rupture	P00H0037
DECEMBER 28	Trans Québec & Maritimes Pipeline Inc.	Hereford, Que.	Compressor station fire/explosion	P00H0061
JANUARY 2001 17	Enbridge Pipelines Inc. (formerly IPL)	Hardisty, Alta.	Crude oil pipeline rupture	P01H0004
SEPTEMBER 29	Enbridge Pipelines Inc. (formerly IPL)	Stoney Creek, Ont.	Line pipe damage with release	P01H0049

Final Reports

The following investigation reports were approved between 01 November 1996 and 28 February 2002.
*See article or summary in this issue.

DATE	COMPANY	LOCATION	EVENT	REPORT NO.
95-07-29	TransCanada PipeLines Ltd.	Rapid City, Man.	Natural gas pipeline ruptures	P95H0036*
96-02-27	Interprovincial Pipe Line Inc.	Glenavon, Sask.	Crude oil pipeline rupture	P96H0008
96-04-15	TransCanada PipeLines Ltd.	St. Norbert, Man.	Natural gas pipeline rupture	P96H0012*
96-12-11	TransCanada PipeLines Ltd.	Stewart Lake, Ont.	Natural gas pipeline rupture	P96H0049*
97-02-10	Trans-Northern Pipelines Inc.	Vernon, Ont.	Products pipeline material release	P97H0007*
97-04-30	Westcoast Energy Inc.	Fort St. John, B.C.	Natural gas pipeline rupture	P97H0024*
97-12-02	TransCanada PipeLines Ltd.	Cabri, Sask.	Natural gas pipeline rupture	P97H0063*
98-12-08	Westcoast Energy Inc.	Kobes Creek, B.C.	Wet sour natural gas pipeline rupture	P98H0044*
00-08-07	Westcoast Energy Inc.	Coquihalla Highway, B.C.	Natural gas pipeline rupture	P00H0037*

TRANSPORTATION SAFETY
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TSB Mission

The *Canadian Transportation Accident Investigation and Safety Board Act* is the legal framework governing the TSB's activities.

The mission of the TSB is to advance transportation safety by

- conducting independent investigations, including public inquiries, into selected transportation occurrences to make findings as to their causes and their contributing factors
- identifying safety deficiencies
- making recommendations designed to eliminate or reduce safety deficiencies
- reporting publicly on its investigations and findings

It is not the function of the Board to assign fault or to determine civil or criminal liability.

Independence

To encourage public confidence in transportation accident investigation, the investigating agency must be, and be seen to be, objective, independent, and free from any conflicts of interest. The key feature of the TSB is its independence. It reports to Parliament through the President of the Queen's Privy Council for Canada and is separate from other government agencies and departments. Its independence enables it to be objective in arriving at its conclusions and recommendations. The TSB's continuing independence and credibility rest on its competence, openness, and integrity and the fairness of its processes.

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