National Energy Board

Office national de l'énergie

Pipeline Incident Report

Natural Gas Pipeline Rupture near Fort St. John, British Columbia

15 May 2002

Canada

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Cat. No. NE23-119/2004E
ISBN 0-662-37318-9

This report is published separately in both official languages.

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National Energy Board
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For pick-up at the NEB office:
Library
Ground Floor

Printed in Canada

Nº de cat. NE23-199/2004F
ISBN 0-662-77074-9

Ce rapport est publié séparément dans les deux langues officielles.

Demandes d'exemplaires :
Bureau des publications
Office national de l'énergie
444, Septième Avenue S.-O.
Calgary (Alberta) T2P 0X8
Courrier électronique : publications@neb-one.gc.ca
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Imprimé au Canada

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List of Acronyms and Abbreviations

API	American Petroleum Institute
CSA	Canadian Standards Association
°C	degree Celsius, unit of measure
Duke	Duke Energy Gas Transmission
DSAW	double submerged arc welded
EPZ	emergency planning zone
ERW	electric resistance welded
H_2S	hydrogen sulphide
in	inch, unit of measure
J	Joule, unit of measure
kPa	kilopascals, unit of measure
ksi	one thousand pounds per square inch, unit of measure
m	meter, unit of measure
mm	millimeter, unit of measure
MMscf	million standard cubic feet, unit of measure
M.P.	mile post
psi	pounds per square inch, unit of measure
RCMP	Royal Canadian Mounted Police
Samson	Samson Canada Ltd.
SSCC	sulphide stress corrosion cracking
WGC	Westcoast Gas Control, located at Charlie Lake at the north end of Fort St. John

Executive Summary

At approximately 15:08 Mountain Standard Time on 15 May 2002, an 18-inch diameter natural gas transmission pipeline owned by Westcoast Energy Inc., carrying on business as Duke Energy Gas Transmission, ruptured at a location adjacent to the Alaska Highway near the city of Fort St. John, British Columbia. The rupture occurred on a sending barrel at a valve station. A Westcoast employee was working on the sending barrel when it ruptured and was knocked to the ground, but was otherwise unhurt. The rupture in the pipeline resulted in the release of approximately 3.73 MMscf of sour (0.41per cent H_2S) natural gas. The released gas did not ignite and developed into a plume which was blown by the wind toward nearby residences and a trailer park until the gas dissipated. There were no injuries resulting from the rupture. According to Westcoast Energy Inc., property and other damages or losses totaled $139,960.

The emergency response to the incident was coordinated by Westcoast until the onsite arrival of the Taylor Fire Chief who assumed the role of the Field Incident Commander. Westcoast immediately isolated the section of the pipeline from gas sources by closing line break valves upstream and downstream of the rupture. The emergency response resulted in stoppages of traffic on the Alaska Highway, as well as between the highway and the airport and the Baldonnel Elementary School. Notification to the airport of the rupture and gas plume resulted in the issuance of flight restrictions for the affected area by the airport's flight services. Rail traffic was also stopped on a rail line in the path of the gas plume.

Westcoast began phoning residents in the affected emergency planning zone with a "shelter in place" message, meaning that the residents should stay in their homes until the situation had been resolved or it had been determined it was safe to evacuate. Having heard the initial rupture and having witnessed the developing gas plume, many residents in the immediate vicinity of the incident had already begun to evacuate themselves. After observing the direction of travel of the gas plume, the Taylor Fire Chief made the decision to evacuate any remaining people in the area downwind from the incident site, as well as the Edgewood Trailer Park and surrounding housing. Attempts to contact residents in the emergency planning zone by Westcoast were discontinued when it became apparent that all residents were being evacuated. Since the school day was drawing to a close, the Baldonnel Elementary School was loading children onto school buses when the rupture occurred. A local resident notified the school of the rupture and to avoid travel westward towards the rupture and the evolving gas plume.

After testing did not find any measurable levels of H_2S at the Alaska Highway, the Edgewood Trailer Park, and the Baldonnel School, the area was declared safe. Traffic blocks on the highway were removed, flight restrictions for the area were removed, and the rail line was reopened. The time from the rupture of the pipeline to Field Incident Commander declaring the situation safe and secure was approximately two hours and twenty minutes.

Westcoast sent the section of ruptured pipe to an independent laboratory for detailed metallurgical failure analysis and physical examination. The National Energy Board investigation included a review of laboratory analysis, Westcoast documentation available for the ruptured pipe, Westcoast procedures and records.

The National Energy Board investigation of the rupture resulted in the following findings:

1. The pipeline rupture was likely caused by a shock wave or impact created after a hydrate or ice plug blockage was released by a differential pressure.

2. At the time of the incident, the sending barrel pipe was in a weakened condition caused by the large centerline laminations that had accumulated elemental hydrogen, creating an inward bulge.
3. The sending barrel was idle for two years allowing fluids to accumulate.
4. The ruptured pipe did not meet the toughness requirements of the applicable CSA design standard in effect at the time of pipe fabrication and construction.
5. Westcoast did not have the necessary documentation for the materials and design of the sending barrel.
6. There was a lack of communication between the Westcoast Incident Commander and the Taylor Fire Departments Field Incident Commander.

As a result of the investigation into the rupture of the 18-inch Fort St. John natural gas transmission pipeline, the NEB directs Westcoast as follows:

Directive 1

Westcoast shall review its Operations Manual to ensure the safe operation of pipelines that transport raw gas or residue gas, paying particular attention to:

a) hydrate prevention program;

b) the prevention of liquids accumulation;

c) procedures for the safe handling and removal of hydrates.

Directive 2

Westcoast shall ensure that its pipeline or aboveground facilities integrity management programs provide for regular inspection and assessment of above ground piping in conformance with paragraph 8.8.1 of the Westcoast OPR'99 audit of T-Central in 2001.

Directive 3

Westcoast shall review its pipeline system records for the specifications and material properties related to the reuse of materials or equipment for projects executed since 1999. Westcoast shall determine the adequacy of such records. Westcoast shall assess the significance of any gaps or deficiencies, develop an appropriate action plan, and submit it to the Board for approval within 60 days of the issuance of this directive.

Directive 4

Westcoast shall review with its first responders, in the Fort St. John area, Westcoast's emergency response plan including the handover of incident command, to ensure a common understanding of its requirements and accountabilities.

Factual Information

Incident Synopsis

At approximately 15:08 Mountain Standard Time on 15 May 2002, an 18-inch-diameter steel pipeline owned by Westcoast Energy Inc., carrying on business as Duke Energy Gas Transmission (Westcoast), ruptured and released about 3.73 MMscf of sour natural gas. The pipeline ruptured at an S-bend section of pipe where the pipe descends underground between a sending barrel and an isolation valve. A Westcoast employee working beside the sending barrel was knocked to the ground, but was otherwise unharmed. There were no other injuries. As of December 2002, Westcoast estimated the total cost of the incident, including repair, cleanup, and restoration, to be $139,960.

The rupture was located within a fenced site on Westcoast's pipeline right-of-way adjacent to a compressor station operated by Samson Canada Ltd. (Samson). There was no ignition of the escaping gas and, as a result, a large sour (0.41per cent H_2S) gas plume developed. The prevailing wind was from the southwest at 19 km/hr, and was blowing the gas plume towards the Edgewood Trailer Park and the Alaska Highway. The trailer park was 300 meters from the incident site. Further downwind of the gas plume were the Baldonnel Elementary School and the flight path of the Fort St. John Municipal Airport.

Incident Narrative

On the afternoon of 15 May 2002, a Westcoast employee began servicing valves at a pigging site located at M.P. 2.47 on the 18-inch Fort St. John pipeline. Valve servicing is a routine maintenance operation which involves lubrication and cycling of the valves between the open and closed position. Adjacent to the Westcoast pigging site is a compressor station where a Samson employee was on site.

After servicing several valves on the adjacent 16-inch Oak pipeline, the servicing of the 18-inch gate valve, which isolates the pig sending barrel from the pipeline, was the next scheduled activity. With the initiation of work on the 18-inch valve, the employee discovered that the pig sending barrel was filled with a condensate and water mixture, which had also filled the power supply line and the gas motor connected to the valve operator. In order to correct this situation, the employee first attempted to drain the barrel by manually opening the isolation valve to allow the barrel contents to drain. When this approach proved unsuccessful, the employee attempted to create a pressure differential to push the liquid contents down the barrel. Despite these actions, the employee determined that there was no flow of fluids from the sending barrel.

Upon further analysis of the situation and after trying to confirm the position of the valve's isolating gate by observing the height of the valve stem, the employee then concluded that the valve stem may have separated from the internal gate. To determine if the gate of the valve was in either the up or down position, the employee first decided to depressurize the sending barrel from the rear flare valve located upstream and adjacent to the gate valve. Upon initiating this action, the employee discovered that the rear flare valve was seized and could not be used to depressurize. Turning his attention to the front flare valve, which is located on the front side of the sending barrel adjacent to the barrel door, the employee discovered that the front flare would open. However, the result of opening the front flare valve immediately extinguished the flame in the flare stack with the sudden surge of liquids being purged from the sending barrel. The employee immediately closed the front flare valve, waited for the flare stack to relight itself, and reopened the front valve at a reduced rate, so as not to extinguish the flare again.

As the barrel was slowly depressurizing, the employee collected his tools and then began to reconnect supply lines to the isolation valve operator. At this point in time, the employee noticed that the pressure gauge at the rear flare valve read 600 psi. A review of gas control records after the incident indicated that the pipeline pressure was actually 743 psi at this time. Checking the pressure gauge at the front flare valve, the employee observed that this gauge read 100 psi. Realizing that there was a problem, the employee was about to head back to the isolation valve when the pipeline ruptured at the point where the sending barrel descended into the ground. The escaping gas and liquids caused the transformer on the overhead power lines to overload resulting in a bright flash witnessed by nearby residents. At the time of rupture the employee was just in front of, and slightly to the side of the barrel door. The rupture caused the sending barrel to shift on its supports and into the employee, striking him at groin level and knocking him to the ground. When the employee stood up, the release of gas and fluids from the pipeline blew the employee into an adjacent fence. The employee noted that he could taste saltwater after being sprayed with the liquids in the pipeline. The employee regained his feet, observed that the pipeline had ruptured at the point where the sending barrel descended into the ground and then climbed over the fence to the Samson compressor site. A Samson employee called Westcoast Gas Control and notified of the pipeline rupture and associated sour gas release.

Emergency Response

With the rupture of the pipeline at approximately 15:08 MST and the escape of the Westcoast employee to the Samson compressor station upwind and adjacent to the pipeline, a Samson employee called Westcoast Gas Control (WGC), located in Fort St. John, at 15:18. The Westcoast employee provided vital information to WGC on the nature of the rupture, the direction of the gas plume and reported that no other personnel were involved. The two personnel then proceeded to evacuate the Samson compressor site to the Alaska Highway at the North Peace Apiaries Ltd. honey farm where they were met by other Westcoast and Samson personnel. Upon arrival, the Westcoast employee was taken to the hospital for examination. Two Samson employees blocked southbound traffic at this location until relieved of these duties by the RCMP at approximately 15:28.

At 15:15, the Fort St. John Fire Dispatch received a 911 notification of the incident. It could not be verified who notified the Fire Dispatch through the 911 call. Notifications to the RCMP, the Taylor Fire Department, and local ambulance were made by the Fire Dispatch by 15:17. At 15:19, Fort St. John Fire Dispatch contacted WGC to confirm the location and relay this information back to the Taylor Fire Department.

Upon notification of the incident at 15:18, the Supervisor from WGC at Charlie Lake temporarily assumed the duties and responsibilities of the Incident Commander role and began to implement Westcoast's Emergency Response Plan. WGC personnel immediately isolated the section of pipeline containing the rupture by closing the 16-inch Oak line break valve at mile post 17.27 and the 18-inch Fort St. John line break valves at mile posts 6.31 and 7.04. By 15:20, all of these valves were considered closed. The rate of gas flow escaping from the ruptured pipeline quickly decreased. By 15:40, on site confirmation was received by WGC of valve closures. Westcoast personnel were also sent to manually shut in all producers at their receipt points.

At 15:18, the control room operator at Westcoast's McMahon Complex in Taylor was notified by

WGC of the incident. An investigative team was immediately dispatched from the McMahon Complex, and arrived on the incident site at 15:33, at the same time as the Taylor Fire Department. At this point in time, the Fire Chief from the Taylor Fire Department assumed the role of Field Incident Commander. Northbound traffic was blocked on the Alaska Highway at the Edgewood Trailer Park. Traffic to the airport and Baldonnel Elementary School was also blocked. At this time, the Taylor Fire Department noted a strong smell of gas and that the wind was moving the gas plume in a north east direction toward the Edgewood Trailer Park.

At 15:28, the RCMP arrived at the road block at the North Peace Apiaries Ltd. honey farm and relieved the Samson personnel manning the southbound traffic road block. At 15:30, the Taylor Fire Department instructed the RCMP to completely close the highway. The RCMP then proceeded to the second road block established by the Taylor Fire Department at the Edgewood Trailer Park. This road block would be moved south to the top of North Taylor Hill at 15:40.

At 15:30 an Incident Command Post was established in the Emergency Response Room at WGC. At the same time Westcoast's Land Resource Agents were delegated to be the telephone notification team and to start contacting residents in the affected emergency planning zone (EPZ). The Westcoast Incident Commander recommended that residents in the affected area should "shelter in place", meaning that the residents stay in their homes until the situation has been resolved or it has been determined it is safe to evacuate. After determining the affected residents from the appropriate site specific emergency response plan and area map, the telephone notification team started phoning residents at 15:40. By 15:45 only one contact had been made, with all other calls having no answer. Attempts to contact residents in the EPZ by Westcoast were discontinued when it became apparent that all residents were being evacuated.

Having heard the initial rupture and having witnessed the developing gas plume, residents in the immediate vicinity of the incident began to evacuate themselves. Since the school day was drawing to a close, the Baldonnel Elementary School was loading children onto school buses when the rupture occurred. A local resident notified the school of the rupture and to avoid travel westward towards the rupture and the evolving gas plume. By 15:25, the Taylor Fire Department was notified that the school had been evacuated. At 15:50, a gas check was performed at the Baldonnel School and no level of H_2S was detected. Also at 15:50, the Taylor Fire Chief made the decision to evacuate people in the downwind area from the incident site, as well as the Edgewood Trailer Park and surrounding housing. Residents in the affected areas were instructed to gather at a site near the south roadblock on the Alaska Highway. At the request of the Taylor Fire Chief, the airport was notified by Fire Dispatch. At 15:40 a "notice to airmen" was issued by the airport's flight services putting flight restrictions in place for the affected area. At 15:50, a B.C. Rail representative confirmed to the Taylor Fire Chief that rail traffic had been stopped. There was no record of how B.C. Rail was notified. The Taylor Fire Chief informed Westcoast's onsite supervisor who relayed the message to WGC that the evacuation of residents was complete at 16:10.

At 16:07, Westcoast personnel performed the first visual inspection of the rupture site and confirmed that there were no remaining personnel in the area and also confirmed that there was no pressure at the gate valve nearest the rupture site. At 16:45, Westcoast personnel began extensive testing of the Alaska Highway and of the Edgewood Trailer Park for the presence H_2S.

Shortly after 17:00, the Edgewood Trailer Park was declared safe and the Alaska Highway road blocks were removed. Flight Services at the airport was also notified at this time that flight restrictions in the area of the rupture could be removed. The B.C. Rail line was reopened. At 17:30, the Taylor Fire Chief declared the situation secure and ordered his team to return to the fire hall. Site control was then returned to Westcoast.

18-inch Fort St. John Pipeline

The 18-inch Fort St. John pipeline was built in 1957 using electric resistance flash welded (ERW) pipe manufactured by A.O. Smith. Over time, sections of the pipeline have been upgraded or altered, such as the sending barrel where the pipeline rupture occurred. According to Westcoast as-built drawings, the sending barrel was moved or modified in 1979. These drawings contain a note which states "material list not as-built". The field and laboratory analysis of the ruptured pipe determined that the pipe was manufactured using a double submerged arc welded (DSAW) process and was therefore not part of the original installation. Westcoast could find no records to identify the origin, grade, or vintage of the ruptured pipe.

For design purposes, the18-inch Fort St. John pipeline crosses through two class location assessment areas, that is, through a class 1 and class 3 designations[1]. In class 1 locations, the pipeline has a wall thickness of 7.1 mm (0.280 inch), a pipe grade of 359 MPa (X52), and a pipe manufacturing standard of API 5LX-52. In class 3 locations, the pipeline has a wall thickness of 7.6 mm (0.300 inch), a pipe grade of 414 MPa, and a pipe manufacturing standard of the Canadian Standards Association (CSA) Z245.1-M1979.

The ruptured S-bend section of pipe between the barrel and the isolation valve had a measured wall thickness of 8.74 mm (0.344 inch). For design purposes, the sending barrel location has a class 1 designation.

The 18-inch Fort St. John pipeline has a maximum operating pressure of 6895 kPa (1000 psi). The normal operating pressure of the pipeline over the previous twelve-month period was 4480 kPa (650 psi) with a maximum operating pressure of 6200 kPa (900 psi) and a minimum operating pressure of 4070 kPa (590 psi).

Laboratory Examination of the Ruptured Pipeline Segment

The ruptured pipe was sent to an independent laboratory for detailed metallurgical failure analysis and physical examination. The pipe was first visually examined and nondestructively tested, after which the steel properties were determined through physical and chemical laboratory analysis. Specifically, a chemical analysis, tensile tests, Charpy impact tests, and hardness testing were performed on samples of the failed pipe material. The results of tensile testing and chemical composition indicated that the pipe steel matches the strength and chemical requirements of API 5LX (1975) Grade 46 steel pipe. When compared to the CSA Z245.4 M1979 Grade 317 pipe specification, the comparable Canadian standard in effect at the time, the carbon content would have been too high. One of the three test specimens exhibited less than the minimal allowed elongation. The strength and chemical requirements and test results are shown in Table 1.

Charpy impact tests of the ruptured pipe steel indicated poor fracture toughness properties with a ductile-brittle transition in the +30°C to +40°C temperature range. Scanning electron microscopy indicated that the entire fracture was comprised of

1. Class location assessment areas that contain 10 or fewer dwelling units are designated class 1 locations. Class location assessment areas that contain 46 or more dwelling units are designated class 3 locations. Class location assessment areas are 1.6 km long and extend 200 m on both sides of the centerline of the pipeline.

Table 1: Rupture Pipe Steel Properties, API 5LX (1975) and CSA Z245.4 M1979 Specifications

	Carbon	Manganese	Phosphorus	Sulfur	Yield Strength min.		Tensile Strength min.		Elongation
	(%)	(%)	(%)	(%)	ksi	MPa	ksi	MPa	(% min.)
Rupture pipe[1]	0.27	0.692	0.008	0.021	47.1 - 50	324.8 - 344.8	68.3 - 70.6	470.9 - 486.5	15 - 31.5
API 5LX Gr 46	0.30[2] max.	1.25 max.	0.04 max.	0.05 max.	46	317	63	434	27
CSA Z245.4 Gr 317	0.26 max.	0.30 min.	0.04 max.	0.04 max.	46	317	63	434	27

1. To determine the physical properties of the ruptured pipe steel three test specimens were taken from intact regions of the arrest zone (transverse and longitudinal) and rupture (transverse) zone. The table shows the range of the test results from the three specimens.

2. For non-expanded welded (non-seamless) grade X46 pipe only. For cold expanded welded grade X46 pipe the maximum carbon content allowed is 0.28 per cent.

brittle cleavage features away from the fracture initiation zone. API 5LX (1975) pipe standard has no requirement for specifying toughness properties of pipe steel unless requested by purchaser. The requirements for specifying toughness properties in CSA Z245.4-M1979 are determined by the design operating conditions of the pipe. The metallurgical analysis did not detect any hardness areas along the submerged arc weld zone.

Visual examination of the ruptured pipe revealed that the rupture initiated at a large lamination[2] in the pipe that was created during the original plate manufacturing process. It is well known that wet hydrogen sulphide inside the pipe dissociates to form iron sulphide and then releases atomic hydrogen. Over time, atomic hydrogen diffused into the steel and accumulated as elemental hydrogen at the lamination in the centerline of the pipe wall. At the rupture origin, the accumulated gases had formed a large hydrogen blister[3] bulging inward from the lamination and separating the inner ply from the opposing layer of material. Yielding of the inner layer of steel occurred, resulting in a permanent bulge and significant residual stresses associated with the bulge. Sulphide stress corrosion cracking (SSCC) was found on the inner ply of the steel that penetrated to the inside surface of the outer ply of steel. Shallow SSCC was also found on the inside surface of the outer ply of steel. The SSCC occurred in and around the bend zone, due to continuing hydrogen sulphide dissociation and the high residual stresses associated with the bulge.

2. Laminations are internal metal separations creating layers generally parallel to the surface. Some laminations are caused by a shrinkage cavity in the upper part of an ingot. If oxides form on the surface of this cavity, the surfaces will not weld together during subsequent rolling operations. Since the shrinkage cavity starts at the center of an ingot, it will remain in the center of the resulting slab, plate, or pipe wall.

3. Hydrogen blistering is caused by the diffusion of atomic hydrogen into the steel. Normally the hydrogen tends to diffuse through the steel. However, when reaching a void, lamination, etc. the atomic hydrogen changes to molecular hydrogen. The continued penetration of atomic hydrogen results in the formation of more and more molecular hydrogen thus causing a high internal pressure resulting in a blister.

As a result of substantial SSCC, the interior surface of the lamination, at the blister, was eventually opened up allowing a through wall path for gas and liquids to the remaining outer wall. It is assumed that at the time of the rupture the pressure inside the blister matched the internal pressure in the sending barrel. With the inner ply of the blister not providing support for pressure containment, the rupture occurred when the applied stress intensity at the outer ply crack tips exceeded critical levels. Calculation of the failure pressure, utilizing fracture mechanics models and using measured pre-existing defect sizes, indicates that the failure pressure would have been about 1000 psi. This level of stress is 30 per cent above that generated by the reported line pressure of 743 psi.

CSA Design Code Toughness Requirements

The Gas Pipelines Systems design standard in effect at the time of construction of the sending barrel would have been either CSA Z184-M1979 or CSA Z184-M1975, depending on the date of design and construction. Construction or relocation of the sending barrel is thought to have occurred in 1979 or 1980. No mill certificates could be found in Westcoast's records that would confirm the origin, grade or vintage of the pipe. Therefore, the results obtained from the metallurgical analysis of the ruptured pipe joint were utilized to assess the sending barrel design, and compliance with the applicable design standard. A review of the design requirements for pipe toughness properties shows that the ruptured section of pipe did not meet the requirements of either CSA Z184-M1979 or CSA Z184-M1975. These pipe toughness property requirements are listed in appendix A.

The absorbed energy values determined by testing of the rupture pipe showed poor properties, with a range of 7 to 14 J over a temperature range of -5°C to +20°C. The actual or measured absorbed energy is significantly below the minimum absorbed energy of 20 J at a temperature of -45°C specified by CSA Z184-M1979 or the minimum absorbed energy of 27 J at a temperature of -45°C specified by CSA Z184-M1975. It should be noted that the absorbed energy value specified is a minimum value, and individual pipeline designs may require higher levels of specified absorbed energy.

In the current design standard for pipeline design, CSA Oil and Gas Pipeline Systems Z662-99, for pipe runs of less than 50 m it is permissible to substitute pipe without proven notch toughness properties. Although this pipe steel had poor notch toughness properties, and therefore poor protection from fracture initiation and propagation, it would be acceptable for use according to the current design standard.

Pipeline In-line Inspections

A metal loss in-line inspection of the 18-inch Fort St. John pipeline was last performed in 1998 using a magnetic flux leakage tool. Magnetic flux leakage tools are best suited for detecting metal loss, but can offer limited detection of defects such as laminations. After the rupture, Westcoast reviewed the results of the inspection run and did not find any indications of an anomaly at the sending barrel.

Liquids Management

Purging of liquids from the sending barrel was previously only done by Westcoast when there was evidence of liquids accumulation. According to Westcoast operations personnel, accumulation of liquids in the sending barrel only occurred in early 2000 for a short period of time, prior to servicing of the kicker line valve on the bypass and the two barrel flare valves. At that time, a temporary procedure for purging the sending barrel was implemented because a smoke plume was emitted during regular flaring associated with receiving a cleaning pig on the adjacent 16-inch Oak pipeline.

This type of smoke plume was attributed to accumulated liquids from minor valve weeping. After the valves were serviced, the accumulation of liquids in the sending barrel was considered to have ceased since there were no further smoke plumes observed with receiving pigs on the 16-inch Oak pipeline. As a result, the temporary procedure for purging liquids from the sending barrel was discontinued. Westcoast indicated that the last time the 18-inch Fort St. John pipeline sending barrel had been purged of liquids prior to the rupture was in April 2000. Westcoast operations personnel reported that the 18-inch Fort St. John pipeline is no longer pigged for liquid management purposes.

Westcoast reported that the 18-inch Fort St. John pipeline and associated facilities are designed and equipped to accommodate significant volumes of liquids. McMahon Gas Plant, the delivery point for the pipeline, can accept slug sizes of 1600 barrels during normal operations. The 18-inch Fort St. John pipeline has been simulated for multiphase flow behavior.

The flare at the site of the sending barrel was not designed to accommodate fluids in the line. Westcoast reported that the engineering and procurement of materials to install liquid knockout facilities at the site was underway before the incident, with the work scheduled to be completed by the end of 2002.

Gas Quality

Westcoast enters into contractual agreements providing raw gas transmission, treatment, liquid products stabilization and fractionation services to shippers in the Fort St. John resource area. The terms and conditions of the agreement require that shippers deliver gas that is within a product specification, and that Westcoast shall not be obliged to take delivery of any raw gas, residue gas or hydrocarbon liquids which do not comply with the applicable quality specifications. These quality specifications include limits for water content in the raw gas in either liquid or vapour form. The specific requirements for the 18-inch Fort St. John pipeline include, in addition to other quality requirements, the following clauses concerning water content:

Raw gas shall:

a) not contain water vapour in excess of 65 milligrams per cubic meter, as determined by dewpoint apparatus approved by the Bureau of Mines of the United States, but in no case need the raw gas be dehydrated to a water vapour dewpoint of less than minus 12°C at the delivery pressure, and

b) be free of water in liquid form.

Westcoast takes custody of the raw gas and hydrocarbon liquids at a receipt point owned and operated by a shipper. The receipt point operator is obligated to deliver gas and hydrocarbon liquids that meet the quality specifications of the terms and conditions of the contract, as well as being responsible for the accuracy and maintenance of all gas or hydrocarbon test equipment required for maintaining these specifications. The receipt point operators on the 18-inch Fort St. John pipeline schedule and perform manual dewpoint checks in accordance with Westcoast's measurement policy. Westcoast performs its own manual dewpoint check on all new receipt points upon their commissioning. Additionally, Westcoast will occasionally witness the receipt point operator's routine manual dewpoint testing.

A review of the dewpoint testing records for the past two years on the 18-inch Fort St. John pipeline and upstream pipelines revealed some receipt points exceeding the dewpoint specification of 65 milligrams per cubic meter. The highest water vapour measurements were observed at the Samson compressor station located adjacent to the sending barrel site. The18-inch Fort St. John pipeline receives gas from the Samson compressor station at a connection point immediately downstream from the isolation valve for the ruptured sending barrel. The Samson compressor station also supplies gas during pigging or purging operations directly to the sending barrel through the kicker line.

Westcoast's policy for water vapour measurements on the 18-inch Fort St. John pipeline that are outside the specified requirements involve working with the receipt point operator to resolve the problem first prior to shutting in the receipt point. The operator will be given the opportunity to explain any out of the ordinary circumstances contributing to the high dew point, and a grace period will be determined by Westcoast personnel to correct them. If the receipt point operator fails to meet the gas quality requirement after the grace period, then the receipt point will be shut in. The receipt point will be reopened after the operator verifies, according to Westcoast's procedures, that they are within the specified gas quality requirements.

Analysis

Hydrate Formation

Since the fracture mechanics analysis indicates that the pressure required for the rupture of the pipe exceeded the reported line pressure, an additional event or stressor would have been required to cause the rupture. This would most likely have come from the suspected hydrate plug being dislodged and creating a pressure wave within the pipeline. There was no evidence within the ruptured pipeline remains that would prove the presence of a hydrate plug. However, the pressure differential reported by the operator prior to the pipeline rupture can only be explained by a plug between the rear flare line gauge and the barrel door gauge. The operator's actions of attempting to purge and depressurize the barrel would have been enough to cause the hydrate plug to dislodge. When the blockage became dislodged, a "hammer" effect, sufficient to initiate fracture in the steel, was generated.

Hydrates are mixtures of water and gas molecules that crystallize to form a solid "ice plug" under appropriate conditions of temperature and pressure. Hydrates can form from free water condensed in the gas stream at or below its water dewpoint. Hydrates commonly occur within the pipeline and reservoir environments and can create blockages in pipelines. The primary considerations which promote hydrate formation are low temperature, high pressure, and the gas must be at or below its water dew point with free water present. An unusual feature of hydrates is that their formation is not strictly temperature dependent. They form at high pressure when the temperature of the flowing gas is well above the freezing point of water. Based on evidence collected at the incident site, the conditions in the sending barrel would have been optimal for the formation of hydrates.

Hydrates, like any other obstruction in a pipeline, can be detected by the consequences they create. Obstructions will reduce flow, increase backpressure on a system, and increase the differential pressure across the obstruction. Differential pressure can quickly accelerate a hydrate plug to velocities approaching the speed of sound, creating excessive forces. Moving hydrates can cause serious mechanical damage at downstream locations where restrictions, obstructions or sharp change of direction exist. The failure can be impact or overpressure (shock wave) failure. Impact failures occur due to the mass and momentum of the hydrate hitting and fracturing the pipe or fittings.

Since the size and location of the blockage is not known, it is impossible to estimate the amount of force that the dislodged plug generated within the sending barrel prior to failure. The sending barrel ruptured at its weakest point, a flaw introduced in the manufacturing process that further deteriorated during operation of the pipeline. In the absence of the flaw, it is possible that the sending barrel still would have ruptured either at its next weakest point due to overpressure or as a result of the impact of the ice plug on the door of the sending barrel.

Pipe Quality

The section of pipe which ruptured exhibited exceptionally poor metallurgical, mechanical, and physical properties. Pipe toughness properties were below those values required by the applicable CSA design standard in effect at the time of pipe fabrication and construction of the Westcoast facilities.

At the time of the incident, the sending barrel pipe was in a weakened condition caused by the large centerline laminations that had accumulated elemental hydrogen which created inward bulging. Fracture analysis determined that the sulphide stress corrosion cracking and the cracking associated with the bulging effectively removed more than 50 per cent of the load-bearing carrying capacity of the pipe. Fracture stress analysis indicated that an additional stress beyond that created by line operating pressure was required to initiate the fracture.

Although the sending barrel did not rupture due to the line operating pressure alone at the time of the incident, the deterioration of the pipe as a result of the lamination and bulging would have continued to progress under normal operating conditions. It is reasonable to conclude that the sending barrel would eventually fail during normal operations.

Operating History

From a detailed review of the events immediately before and after the rupture, it is evident that a significant amount of liquid was present in the sending barrel. The operator's first attempt to purge the barrel of liquids extinguished the pilot on the flare stack. When the barrel ruptured, the area was sprayed by salt water with enough force to trip the transformer on a nearby overhead power line. The operator onsite during the rupture could taste salt water in the spray. After the rupture, when the six inch kicker line to the barrel was disassembled, it was found to be half filled with salt water. It can be assumed the sending barrel was also at least half filled with salt water.

The operating history suggests that water would have had considerable time to accumulate as the sending barrel was last purged of liquids in April 2000. As the rupture occurred in May of 2002, it is possible that the sending barrel would not have seen any use for two years, with the only activity on the barrel being the valve servicing which the operator was performing at the time of the rupture.

Westcoast considered that the problem of liquid accumulation in early 2000 was remedied by the servicing of the kicker line valve on the bypass and the two flare valves on the 18-inch Fort St. John pipeline sending barrel. The temporary procedure of purging liquids from the sending barrel was discontinued after the valve servicing, based on a smoke plume no longer being generated after regular flaring associated with receiving of a pig on the 16-inch Oak pipeline. Nonetheless, a substantial amount of liquids was present in the sending barrel at the time of the incident.

Westcoast's gas quality records indicate that the receipt point with the highest level of water content was the Samson compressor station which ties in to the 18-inch Fort St. John pipeline just downstream of the isolation valve, and to the sending barrel through the kicker line where one of the valves was serviced in 2000. It is possible that the kicker line valve may have continued to weep after its servicing, and after Westcoast discontinued the temporary purging procedure for the sending barrel. In the subsequent two years that the sending barrel was idle, there were no checks done to see if liquids were accumulating.

Although the pipeline and related facilities are designed to be capable of handling liquids, the operation of the flare at the sending barrel site would have benefited from liquid knockout capabilities. The smoke plume observed after regular flaring associated with receiving of a pig on the 16-inch Oak pipeline may have been prevented by removal of liquids from the flare gas stream before combustion. The operator's first attempt to purge the barrel of liquids resulted in extinguishing the pilot on the flare. Liquid knockout capability may have prevented this from occurring. Westcoast had initiated plans for the addition of liquid knockout capability prior to the incident.

Emergency Response

The following two concerns were noted:

> First, there appears to have been a lack of communication between the Taylor Fire Department's Field Incident Commander and the Westcoast Incident Commander. At the time that Westcoast was notifying affected residents with a "shelter in place" message, the Field Incident Commander had given orders to fire department personnel and the RCMP to evacuate the same residents.
>
> Secondly, the events during the incident were poorly documented and recorded. Westcoast did not provide an accurate and complete history of the response to the incident.

In other aspects, the emergency response to the incident by Westcoast can be considered prompt, efficient and appropriate for this type of incident with hydrogen sulphide involved.

Record Keeping

Documentation was not available for the section of pipe which ruptured. Westcoast could find no records to identify the origin, grade, or vintage of the ruptured pipe. As built records of the construction were deficient.

Records related to construction of the sending barrel were thought to have been destroyed in fires at the Charlie Lake office in either 1987 or 1995.

Conclusions

Findings

1. The pipeline rupture was likely caused by a shock wave or impact created after a hydrate or ice plug blockage was released by a differential pressure.

2. At the time of the incident, the sending barrel pipe was in a weakened condition caused by the large centerline laminations that had accumulated elemental hydrogen, creating an inward bulge.

3. The sending barrel was idle for two years allowing fluids to accumulate.

4. The ruptured pipe did not meet the toughness requirements of the applicable CSA design standard in effect at the time of pipe fabrication and construction.

5. Westcoast did not have the necessary documentation for the materials and design of the sending barrel.

6. There was a lack of communication between the Westcoast Incident Commander and the Taylor Fire Departments Field Incident Commander.

Safety Action Section

Action Taken by Westcoast

Pipeline Reconstruction

As a temporary repair, the barrel, S-bend, and isolation valve were removed and an end cap installed in order to return the18-inch Fort St. John pipeline to service. Westcoast returned the pipeline to service on 18-May 2002.

Shortly afterward, the end cap was removed and a new S-bend and isolation valve were installed. A new barrel will be installed when it becomes available. The new design locates the isolation valve, transition pipe, and sending barrel above ground, with the intention of eliminating a low spot where liquids could accumulate.

Procedures

Westcoast's Safe Work Procedures Sub-Committee reviewed the practices and procedures that involve pigging barrels and isolation valves. The Sub-Committee approved a revision to the task related to opening the front and back blowdown valves.

The previous procedure for this task was to:

> Open the front blowdown 3A slowly, and then open the valve 3B. Always open both blowdowns.

The new procedure for this task is:

> Open the front blowdown 3A slowly, and then open the valve 3B. Always open both blowdowns. While opening valves 3A and 3B both pressure gauges should be monitored carefully. This will require two technicians. If at any time there is more than 100psi differential between the two gauges the blowdown should be discontinued immediately. The immediate supervisor should be advised and a site specific procedure should be developed before proceeding or problem rectified.

Pipeline Integrity

Westcoast has developed and implemented a Pipeline Integrity Program for below ground pipe. Efforts are currently underway to expand this program to include above ground facilities. Westcoast has committed to a completion of an expanded Pipeline Integrity Program document by the end of 2004.

NEB Directives

As a result of the investigation into the rupture of the 18-inch Fort St. John natural gas transmission pipeline the NEB directs Westcoast as follows:

Directive 1

> Westcoast shall review its Operations Manual to ensure the safe operation of pipelines that transport raw gas or residue gas, paying particular attention to:
>
> a) hydrate prevention program;
>
> b) the prevention of liquids accumulation;
>
> c) procedures for the safe handling and removal of hydrates.

Directive 2

> Westcoast shall ensure that its pipeline or aboveground facilities integrity management programs provide for regular inspection and assessment of above ground piping in conformance with paragraph 8.8.1 of the Westcoast OPR'99 audit of T-Central in 2001.

Directive 3

> Westcoast shall review its pipeline system records for the specifications and material properties related to the reuse of materials or

equipment for projects executed since 1999. Westcoast shall determine the adequacy of such records. Westcoast shall assess the significance of any gaps or deficiencies, develop an appropriate action plan, and submit it to the Board for approval within 60 days of the issuance of this directive.

Directive 4

Westcoast shall review with its first responders, in the Fort St. John area, Westcoast's emergency response plan including the handover of incident command, to ensure a common understanding of its requirements and accountabilities.

Appendices

Appendix A

For an installation according to the CSA Z184-M1979, the notch toughness requirements for steel pipe are determined by the minimum design temperature, design operating stress, and nominal wall thickness. The minimum design temperature is taken as the lowest expected operating pipe or metal temperature when the hoop stress exceeds 50 MPa, which can be assumed to be -45°C for the present situation. With the design operating stress of the pipeline exceeding 175 MPa and a nominal wall thickness exceeding 3.00 mm, Category II toughness is specified by the CSA standard. However the CSA standard permits substitutions of Category III pipe for pipe runs where the length of pipe is 50 m or less, as in the sending barrel assembly.

For Category III pipe, the clause 10.3.1.1 of CSA Z245.4-M1979 Line Pipe Standard states;

> The steel shall exhibit an absorbed energy of 20 J minimum, when subjected to full size Charpy V-notch impact test, at the test temperature specified by the purchaser.

Since the actual dates of design and construction are not known, installation of the pipe according to the earlier CSA Z184-M1975 Gas Pipeline Systems design standard is was also considered. For the 1975 CSA standard, the notch toughness property requirements for the ruptured pipe are determined by the operating conditions listed in clause 3.1.2.2, which reads as follows:

> 3.1.2.2 Particular attention shall be given to the tensile properties and the notch toughness properties at the designated temperatures (see Clause 3.1.2.3) when the following designed operating conditions are encountered:
>
> c) Exposed pipelines of all sizes and strength levels when operating at a stress level of over 30 per cent of the specified minimum yield strength.
>
> d) Sour gas pipelines of all sizes and strength levels when operating at a stress level of over 30 per cent of the specified minimum yield strength.

The operating temperature, at which toughness properties are to be specified, is determined by Clause 3.1.2.3 and reads as follows:

> 3.1.2.3 The following temperatures are designated for the operating conditions outlined in Clause 3.1.2.2:
>
> b) For exposed pipelines, the lowest expected temperature shall take into consideration the lowest air temperature for the locality…

The toughness properties as required for these conditions are then listed in clause 3.1.2.4, and reads as follows:

> 3.1.2.4 For all pipelines operating under the conditions listed in Clause 3.1.2.2:
>
> a) The pipe shall display a minimum specified of shear as determined by an impact test.

b) The minimum specified value for percentage of shear shall be as required in the CSA Z245 Series of Standards for Steel Line Pipe.

The applicable line pipe standard for the ruptured section of pipe is CSA Z245.4-1974. The ruptured section of pipe would be assigned a Category III designation, intended for exposed pipe lines requiring specific fracture toughness properties. The CSA standard lists a requirement for both absorbed energy and a displayed minimum shear area in the full size Charpy V Notch Impact Test. Referencing Clause 10.3.2 of the same standard provides an exemption for shorter lengths of exposed pipe and reads as follows:

> 10.3.2 Where the pipe is exposed for 100 feet (30.4 m) or less, and this length includes a valve or flanged connection, only the minimum absorbed energy value may be required.

Referencing Clause 10.3.1 specifies the amount of minimum energy absorption for exposed pipe and reads as follows:

> 10.3.1 In addition a full size Charpy V Notch Impact Test shall display minimum energy absorption of 20 foot-pounds (27.0 J) at the testing temperature.

Figure A1: Map of Taylor - fort St. John Area

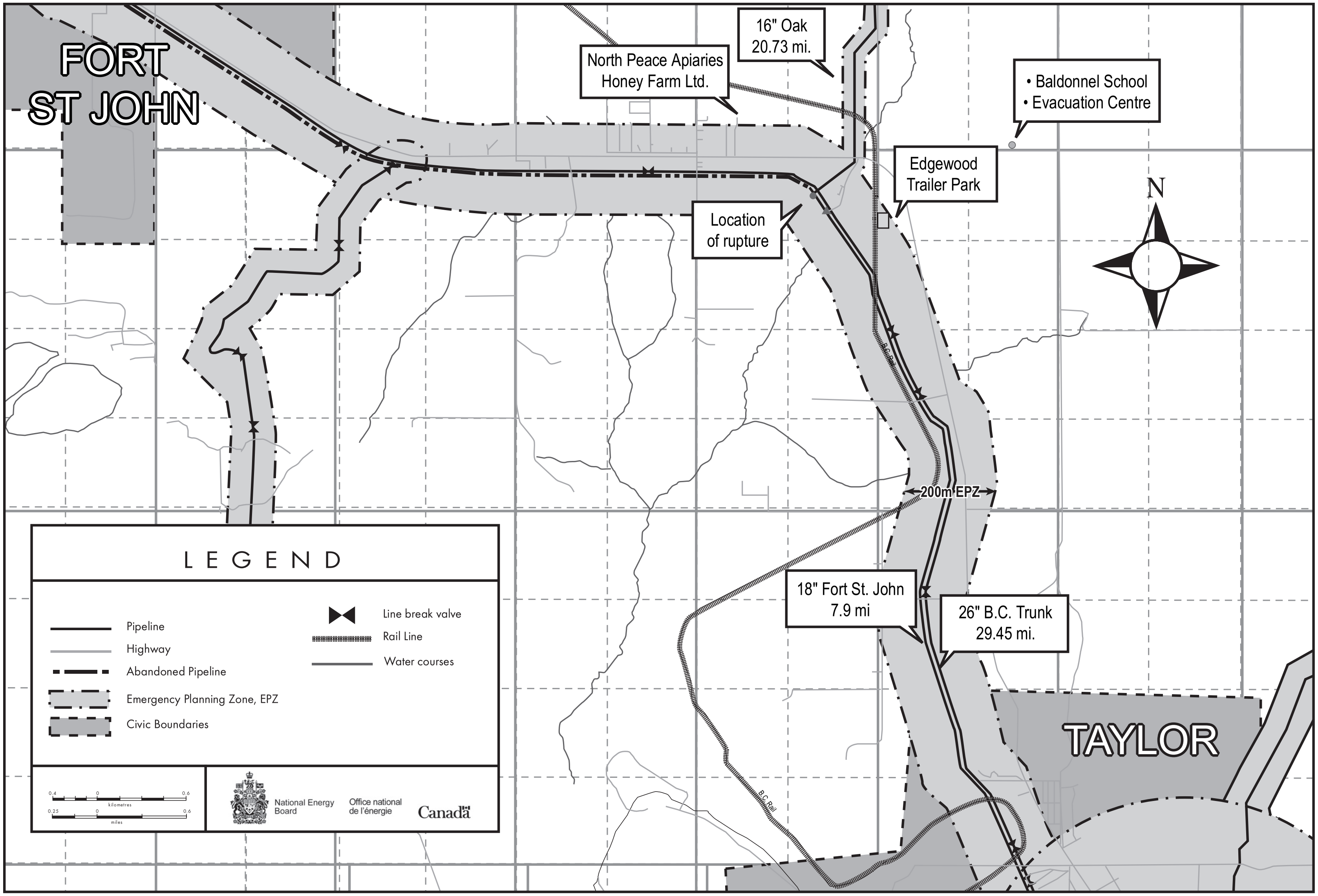

Figure A2: Schematic of Sending Barrel