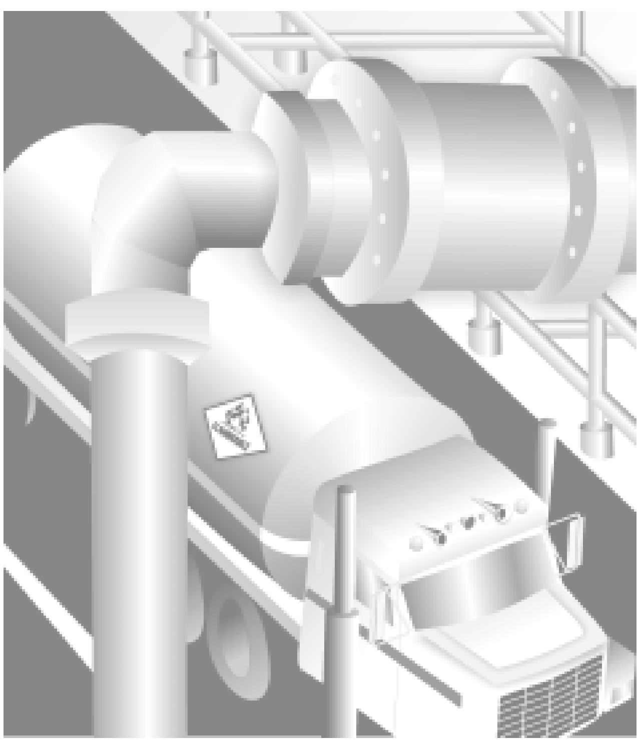
# Rupture of Enbridge Pipeline and Release of Crude Oil near Cohasset, Minnesota July 4, 2002



## Pipeline Accident Report

NTSB/PAR-04/01

PB2004-916501
Notation 7514A

National Transportation Safety Board
Washington, D.C.

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**Adopted June 23, 2004**

**National Transportation Safety Board**
**490 L'Enfant Plaza, S.W.**
**Washington, D.C. 20594**

**National Transportation Safety Board. 2004.** ***Rupture of Enbridge Pipeline and Release of Crude Oil near Cohasset, Minnesota, July 4, 2002.*** **Pipeline Accident Report NTSB/PAR-04/01. Washington, DC.**

**Abstract:** About 2:12 a.m., central daylight time, on July 4, 2002, a 34-inch-diameter steel pipeline owned and operated by Enbridge Pipelines, LLC ruptured in a marsh west of Cohasset, Minnesota. Approximately 6,000 barrels (252,000 gallons) of crude oil were released from the pipeline as a result of the rupture. The cost of the accident was reported to the Research and Special Programs Administration Office of Pipeline Safety to be approximately $5.6 million. No deaths or injuries resulted from the release.

The safety issues identified in this accident are the effectiveness and application of line pipe transportation standards and the adequacy of Federal requirements for pipeline integrity management programs.

As a result of its investigation of this accident, the Safety Board issues safety recommendations to the Research and Special Programs Administration, the American Society of Mechanical Engineers, and the American Petroleum Institute.

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# Executive Summary

About 2:12 a.m., central daylight time, on July 4, 2002, a 34-inch-diameter steel pipeline owned and operated by Enbridge Pipelines, LLC ruptured in a marsh west of Cohasset, Minnesota. Approximately 6,000 barrels (252,000 gallons) of crude oil were released from the pipeline as a result of the rupture. The cost of the accident was reported to the Research and Special Programs Administration Office of Pipeline Safety to be approximately $5.6 million. No deaths or injuries resulted from the release.

The National Transportation Safety Board determines that the probable cause of the July 4, 2002, pipeline rupture near Cohasset, Minnesota, was inadequate loading of the pipe for transportation that allowed a fatigue crack to initiate along the seam of the longitudinal weld during transit. After the pipe was installed, the fatigue crack grew with pressure cycle stresses until the crack reached a critical size and the pipe ruptured.

The following safety issues were identified during this investigation:

- The effectiveness and application of line pipe transportation standards.
- The adequacy of Federal requirements for pipeline integrity management programs.

As a result of its investigation of this accident, the Safety Board issues safety recommendations to the Research and Special Programs Administration, the American Society of Mechanical Engineers, and the American Petroleum Institute.

# Factual Information

## Accident Synopsis

About 2:12 a.m., central daylight time, on July 4, 2002, a 34-inch-diameter steel pipeline owned and operated by Enbridge Pipelines (Lakehead), LLC[1] ruptured in a marsh west of Cohasset, Minnesota. (See figure 1.) Approximately 6,000 barrels (252,000 gallons) of crude oil were released from the pipeline as a result of the rupture. No deaths or injuries resulted from the release.

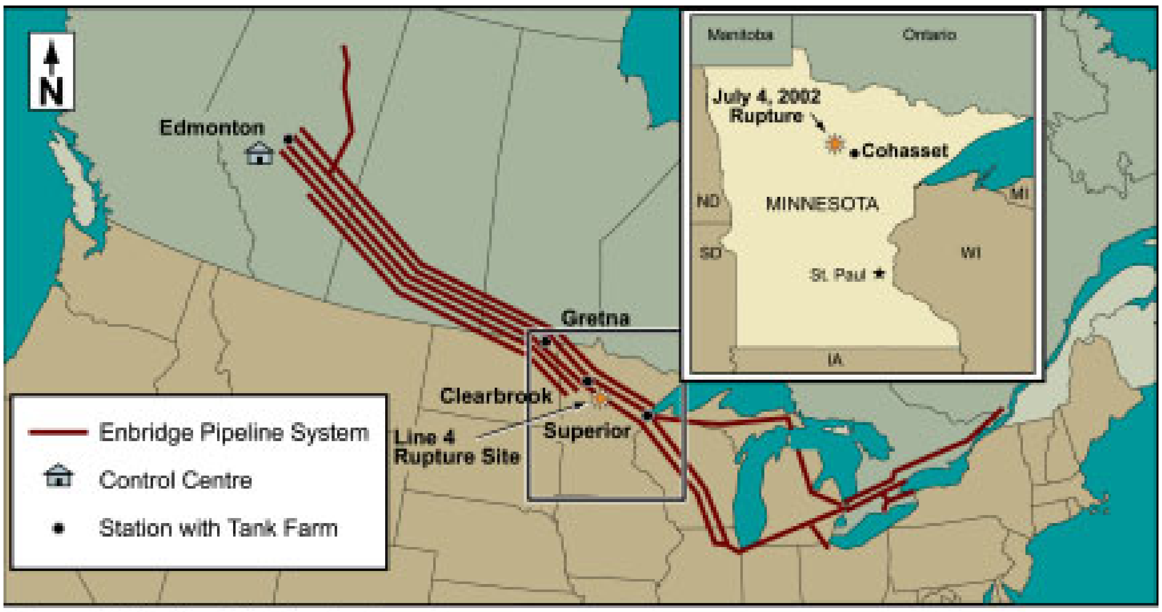


**Figure 1.** Enbridge pipeline system.

## Accident Narrative

The crude oil pipeline involved in the accident originated at Edmonton, Alberta, Canada, and terminated at Superior Terminal in Superior, Wisconsin. The 34-inch-diameter pipeline, designated line no. 4 at the time of the accident, was operated by pipeline controllers in the Enbridge control center in Edmonton using a supervisory control and data acquisition (SCADA) system.[2] About 2:12 a.m. on July 4, 2002, the

[1] Enbridge Pipelines (Lakehead), LLC is the operator of the pipeline system formerly named Lakehead Pipe Line Company.

[2] Pipeline controllers use a computer-based SCADA system to remotely monitor and control movement of oil through pipelines. The system makes it possible to monitor operating parameters critical to pipeline operations, such as flow rates, pressures, equipment status, control valve positions, and alarms indicating abnormal conditions.

controller operating the line observed a SCADA system indication of a loss of suction and discharge pressure at the Deer River pump station. (See figure 2.) At 2:13 a.m., the Floodwood pump station suction pressures began dropping, and then audible and visual alarms were received for an invalid suction pressure. The controller initially suspected an inaccurate pressure transmitter at Floodwood, because the suction pressure had gone to zero. Subsequently, he noticed that the discharge pressure for Floodwood was also dropping and realized that he had an abnormal condition. The controller showed the shift coordinator the situation, and, suspecting a possible leak, they agreed at 2:14 a.m. to shut the pipeline down. At 2:15: a.m., the controller initiated closure of the pipeline injection valve at the Clearbrook Terminal and began shutting down pumps and remotely closed valves to isolate the suspected leak. The upstream valve at Deer River and the downstream sectionalizing valve at milepost (MP) 1017.9 were remotely closed by 2:21 a.m., which isolated the ruptured section. All remotely controlled valves on the pipeline from Clearbrook to Superior Terminal were closed by 2:32 a.m.

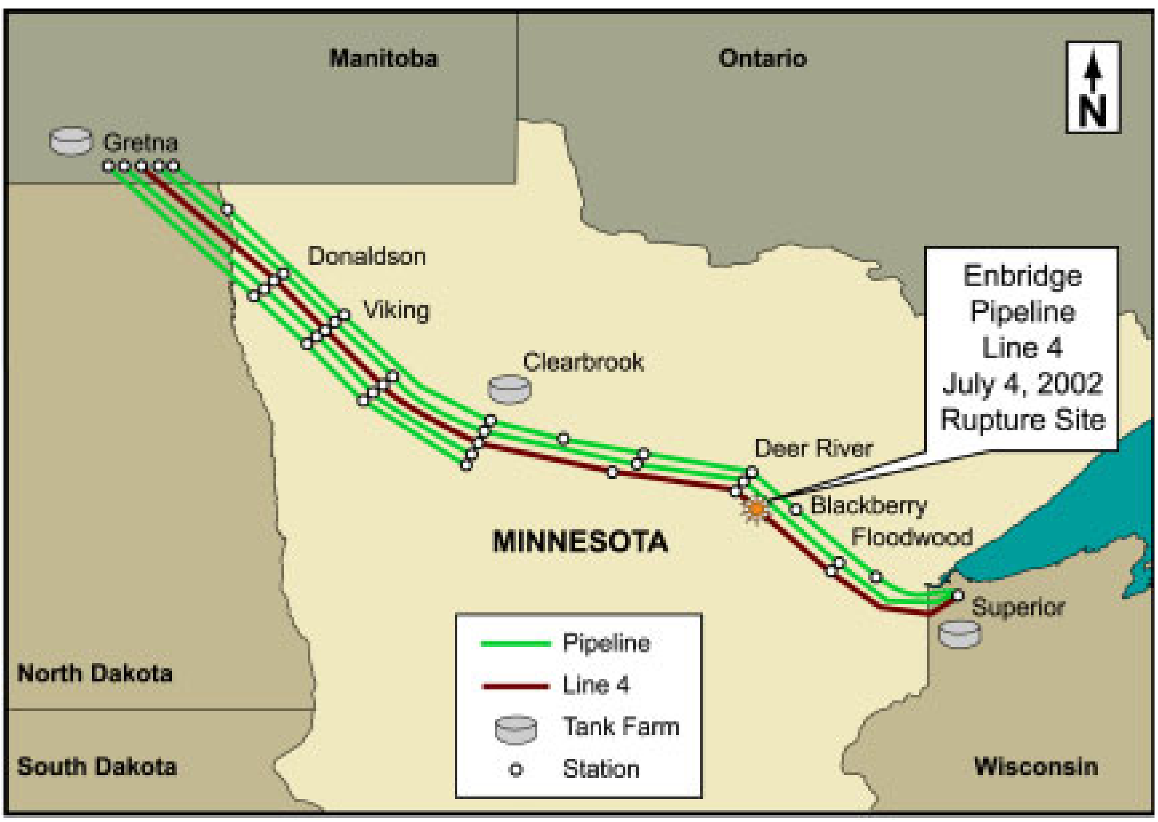


**Figure 2.** Enbridge pipeline facilities and rupture site.

About 2:25 a.m., the Enbridge control center notified the Deer River and Floodwood police departments of the suspected leak, and about 2:30 a.m., Enbridge field personnel were notified. About 5:20 a.m., Enbridge field personnel dispatched to investigate along the pipeline right-of-way detected the odor of crude oil in a marshy area near Blackwater Creek and manually closed the closest valve to the failure. This valve was near MP 1007.32, about 4 1/2 miles downstream (east) of the rupture.

At 7:00 a.m., after Enbridge field employees verified the release, Enbridge notified the National Response Center of a crude oil leak in the company's 34-inch pipeline. This notification indicated that an unknown amount of crude oil had been released. The pipe was found to have ruptured at MP 1002.73, about 7 miles downstream of the Deer River pump station. The company then contacted local, State, and Federal officials, as well as Enbridge spill response contractors, who proceeded to the spill site. Enbridge also had right-of-way representatives contact landowners in the vicinity of the spill. At 12:09 p.m., Enbridge called the National Response Center again and updated the spill volume to 6,000 barrels of crude oil. At the time of the accident, Enbridge had not designated the area where the rupture occurred as a high-consequence area[3] based on the criteria defined in 49 *Code of Federal Regulations* (CFR) Part 195, "Transportation of Hazardous Liquids by Pipelines."

## Emergency Response

Booms were placed in Blackwater Creek as a precaution to prevent crude oil from moving away from the spill site toward nearby waterways, including the Mississippi River. Enbridge started building a 1/4-mile-long road along the right-of-way to the spill site using wood mats. With heavy rain forecast, responders were concerned that the crude oil might spread farther and contaminate the Mississippi River. The unified command for the accident response was established and included the Cohasset Fire Department, Enbridge, the Minnesota Pollution Control Agency, the Minnesota Department of Emergency Management, and the Forestry Division of the Minnesota Department of Natural Resources.

The unified command decided that the best way to prevent the crude from entering nearby waterways was to perform a controlled burn. As a precaution, the command designated 12 homes in the local area to be evacuated, and seven residents were evacuated. Later in the afternoon, the Minnesota Department of Natural Resources coated the spill's perimeter with chemical fire retardant from tanker planes. After the chemical was placed, flares were shot into the crude oil to ignite the oil.

The controlled burn was ignited about 4:45 p.m. (See figure 3.) The burn created a smoke plume about 1 mile high and 5 miles long. (See figure 4.) The controlled burn lasted until about 5:00 p.m. the next day, July 5. While they monitored the fire, Enbridge personnel, firefighters, and environment authorities also monitored the spill perimeter to ensure that no crude was getting into area waterways. Reportedly, no free-flowing product reached any of the boomed areas.

[3] *High-consequence area* refers to commercially navigable waterways, high population areas, concentrated population areas, or unusually sensitive areas that might be affected by an accident involving the pipeline in that area. Title 49 CFR 195.450, 195.452, and 195.6 contain the criteria for designating an area a high-consequence area for hazardous liquid pipelines.

**Figure 3.** Controlled burn surrounded by white fire retardant.

**Figure 4.** Smoke plume 1 mile high and 5 miles long.

## Damage

The cost of the accident was reported to the Research and Special Programs Administration (RSPA) Office of Pipeline Safety to be approximately $5.6 million.[4] Enbridge recovered 2,574 barrels of oil and estimated that the in situ burn consumed approximately 3,000 barrels, with the remainder being lost to evaporation or entrapment in the soil.

## Postaccident Inspection

On July 6, after vacuum trucks had removed the remaining oil and water, the ruptured pipe was exposed. The pipe was fractured along the edge of a longitudinal weld. When the pipe that failed was installed, the longitudinal weld was at the 5:30 clock position when viewed facing downstream (eastward). The rupture was about 69 inches long and gapped open about 6 1/4 inches at the center. (See figure 5.) At the rupture location, the pipeline was rated for a regulatory maximum operating pressure of 687 pounds per square inch, gauge (psig). The pressure at this location at the time of failure was calculated to be 526 psig. The United States Steel Corporation (U.S. Steel) manufactured the pipe at its National Tube Works in McKeesport, Pennsylvania.

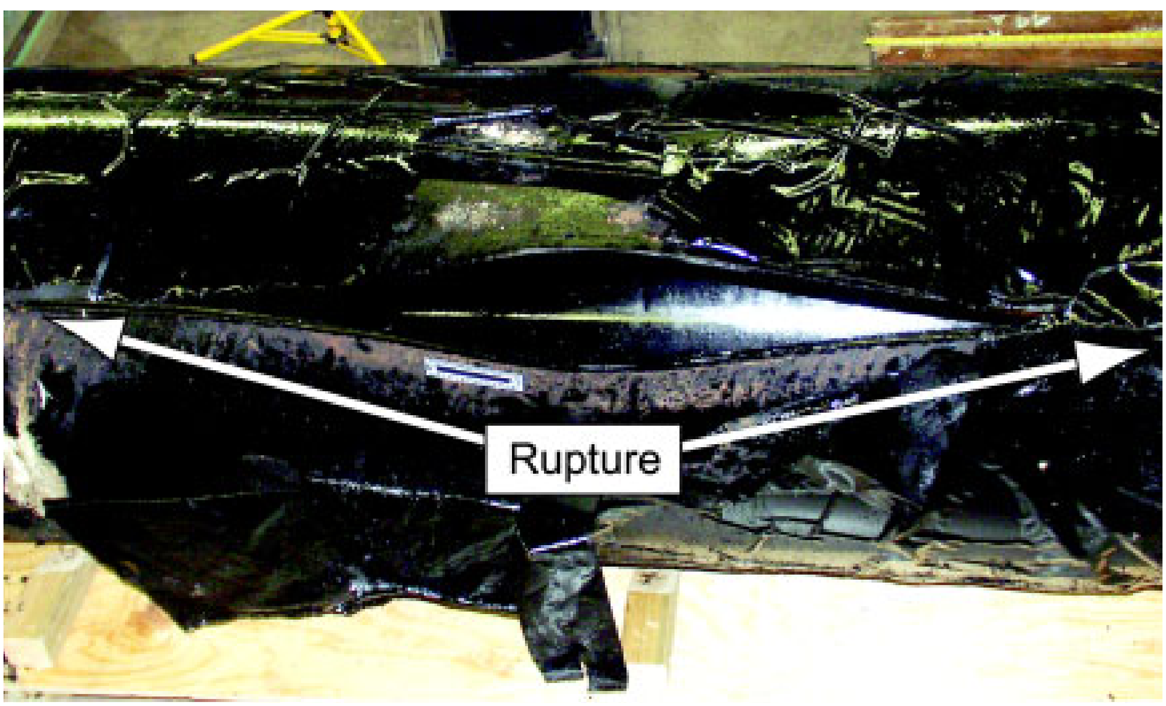


**Figure 5.** Rupture in accident pipe.

[4] This total includes estimated property damage, including cost of cleanup and recovery, value of lost product, and damage to the property of the pipeline operator and others.

## Tests and Research

Two sections of pipe, one containing the rupture and one from the same length of pipe, were removed and sent to the Safety Board's Materials Laboratory for metallurgical examination. The pipe that ruptured was manufactured in accordance with American Petroleum Institute (API) standard 5L, grade X52, indicating that the steel had a specified minimum yield strength[5] of 52,000 pounds per square inch (psi). The 34-inch outside diameter pipe was specified as 0.312-inch nominal wall thickness with a double submerged arc weld (DSAW) longitudinal seam weld. The pipe had a diameter-to-wall thickness (D/t) ratio of 109:1. The pipe was coated with a spiral wrap tape that was applied in the field during construction in 1967.

Surface corrosion was visible on the outer surface of the pipe adjacent to the rupture, but no dents, scratches, or gouges were present at any location on the pipe sections examined. The corrosion was assessed as light, with no apparent pitting and little apparent loss of wall thickness. Both pipe sections were ultrasonically inspected for cracks along the longitudinal seam weld, and, other than the rupture that caused the accident, no additional cracks or discontinuities were uncovered. Fatigue cracking[6] has been shown to initiate at seam welds because of changes in geometry, residual stress, and material properties associated with the weld. Metallurgical testing and examination of the ruptured area found no material or manufacturing defect in the steel or the welded seam of the pipe.

Initial examination of the rupture revealed a preexisting fatigue region at the center of the rupture. The fatigue region was 13 inches long adjacent to the inside surface of the pipe and did not extend all the way through the pipe wall. (See figure 6.) More detailed examination showed that the fatigue cracking initiated at multiple locations along the inside surface (see figure 7) at the toe of the longitudinal weld bead. (See figure 8.) Examination of the cleaned fracture surface revealed a darker, more heavily oxidized band adjacent to the inside surface of the pipe that extended the entire length of the fatigue area. The more heavily oxidized portion of the fatigue area penetrated a maximum of about 0.04 inch deep at the center of the rupture. The oxidized band was visible for almost the entire length of the fatigue area. Near its ends, the oxidized portion of the fatigue crack extended about 0.010 inch into the pipe wall. The remainder of the fatigue crack was less oxidized and extended more deeply into the pipe wall over the central 6 inches of the fatigue region. Along approximately 2.5 inches in the central region, the fatigue crack almost penetrated the pipe wall. At its maximum depth, the fatigue crack penetrated through 0.270

[5] *Yield strength* is a measure of the pipe's material strength and is the stress level, expressed in pounds per square inch, at which the material starts to exhibit permanent deformation. Although yield strength is expressed in pounds per square inch, this value is an expression of a pipe material's strength, which is not equivalent to a pipe's internal pressure.

[6] The term *fatigue cracking* is used to describe a progressive cracking of structural material that occurs under repeated loading and may eventually lead to failure. The fatigue crack grows with cyclic loading until the crack reaches a critical length at which the stresses cause it to grow unstably leading to structural failure. Fatigue cracks can initiate at microscopic flaws or weak spots in the material. Once initiated, cracks can grow at stress levels that are quite low in comparison to the material's yield strength.

inch of the 0.297-inch measured wall thickness.[7] Measurement and testing of the pipe showed that it met thickness and strength requirements. The pipe fracture beyond the fatigue crack contained features typical of overstress fracture.

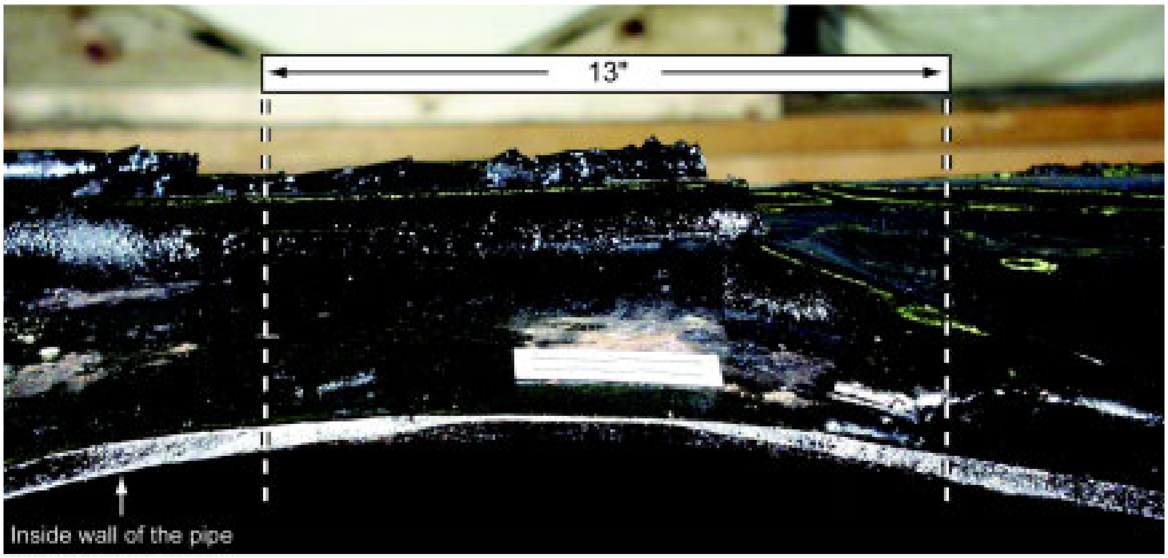


**Figure 6.** View of top fracture surface of 13-inch-long crack, showing penetration nearly through pipe wall in center.

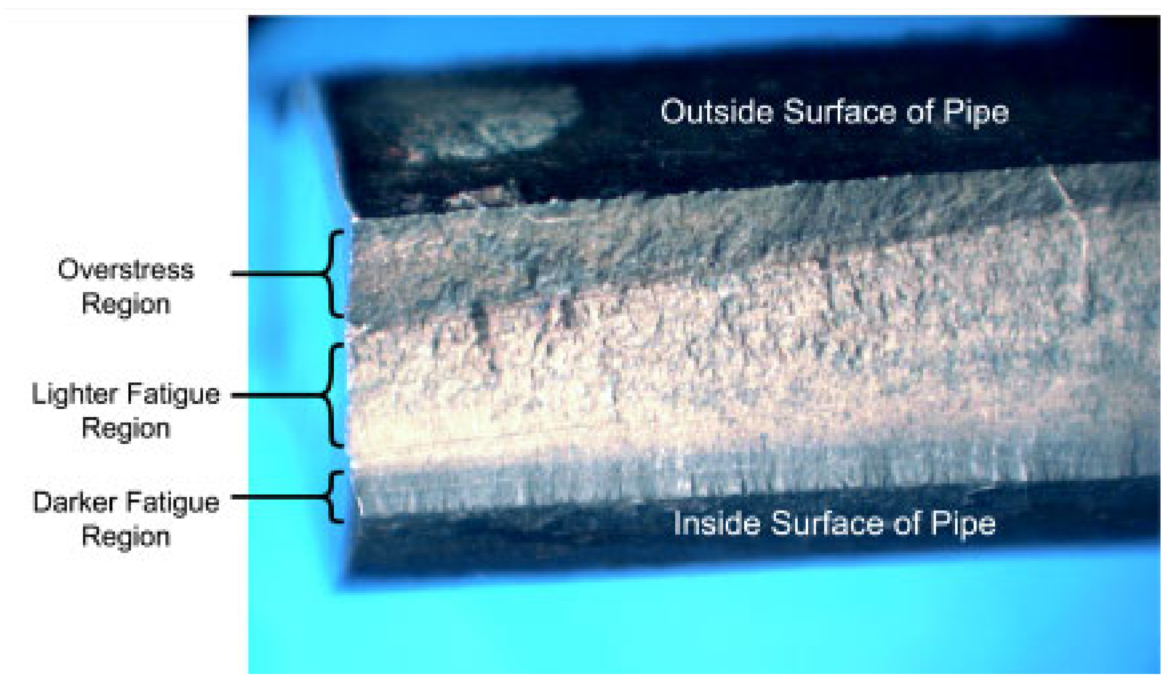


**Figure 7.** Face of fracture in accident pipe.

[7] The 0.297-inch measured wall thickness is within the allowable range for a pipe with 0.312-inch specified nominal wall thickness.

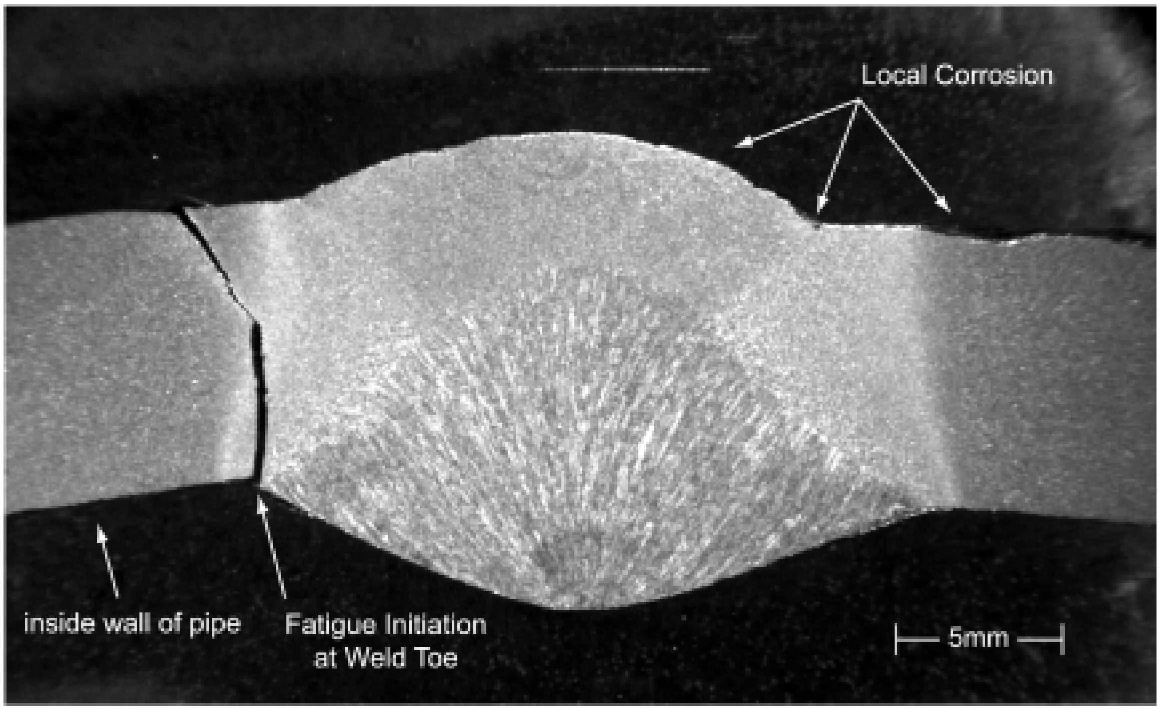


**Figure 8.** Fatigue initiating at toe of weld on interior surface of pipe.

## Preaccident Events

### *Fatigue Cracking in Enbridge Pipe Manufactured by U.S. Steel*

Enbridge's 34-inch U.S. Steel DSAW pipe had a documented history of longitudinal seam weld failures due to fatigue cracks. Metallurgical analysis reports of longitudinal seam weld failures in Enbridge's U.S. Steel pipe in 1974, 1979, 1982, 1986, 1989, and 1991 identified the causes as fatigue cracking at the toe of the weld. Enbridge's 34-inch pipeline system also used A.O. Smith flash-welded pipe, Canadian Phoenix electric resistance welded pipe, and Kaiser Steel submerged arc welded (SAW) pipe. All of the longitudinal seam weld failures caused by fatigue cracks in this pipeline have occurred in pipe manufactured by U.S. Steel.

### *Operational Reliability Assessments of the Pipeline*

After the 1991 pipe rupture at the toe of the weld in the 34-inch pipeline resulted in the release of 40,500 barrels (1,701,000 gallons) of crude oil, Enbridge signed a consent order with RSPA's Office of Pipeline Safety to conduct an operational reliability assessment of the 34-inch pipeline from Gretna, Manitoba, Canada, to Superior, Wisconsin. The assessment was to include a review of pipeline operating conditions and an analysis of the previous pipe failures. The operator was also required to restrict allowable operating pressures, to hydrostatically pressure test[8] the pipeline to establish that the line was safe to operate, and to develop a program to ensure that the line would continue to be safe in the future.

In December 1992, Enbridge performed an operational reliability assessment[9] of the 34-inch pipeline in the United States. As a result of the study, changes were made in pipeline operations that reduced the number of pressure cycles[10] and their associated pressure ranges. Among other actions it took as a result of the 1991 rupture, Enbridge financially and technically supported British Gas's development of the Elastic Wave in-line inspection tool to identify pipe cracks before they precipitate a failure. British Gas did the inspections in 1995 and 1996. PII North American, Inc. (PII), the successor to British Gas, currently provides the inspection tool data report of the Elastic Wave inspection tool in the United States.

The pipeline section in which the 2002 rupture occurred was pressure tested to 835 psig after its construction in 1967. Enbridge's first longitudinal seam weld in-service failure of U.S. Steel pipe from a fatigue crack occurred in July 1974. The entire pipeline, including the pipe joint[11] containing the failure, was pressure tested between 1974 and 1976 at a test pressure of 764 psig. The entire 34-inch pipeline was pressure tested in 1991 and 1992 at higher stress levels than had been used before. Because of variations in pipe wall thickness and changes in elevation in each section of the pipeline, the test pressure range was from 85 percent to 105 percent of the specified minimum yield strength of the pipe, or up to 1,002 psig.[12] The 1991 test pressure at the point of the July 4, 2002, rupture was 937 psig. The operator agreed in 1991 to pressure test the pipeline again in 5 years unless an in-line inspection tool capable of identifying cracks in the longitudinal seam of the pipe was developed. RSPA did not allow the operator to raise the pressures above those in effect at the time of the 1991 accident while the consent order was in effect.

During the 1991 and 1992 pressure testing program, Enbridge found four crack-like/manufacturing defects, four corrosion defects, and one blister. Two subsequent leaks occurred that resulted from pressure-cycle-induced growth of fatigue cracks in U.S. Steel pipe. The two in-service leaks occurred in the first 6 months of 1994 at the site of fatigue cracks that had survived the pressure test levels of the 1991–1992 program. A reassessment report was completed in December 1994 following those two failures. Enbridge's metallurgical report indicated that the initiating fatigue cracks were readily apparent adjacent to the inside pipe wall and had been introduced during the transportation of the pipe, as they were smoother and darker than subsequent fatigue crack growth. The report

[8] A hydrostatic test of a pipeline involves filling the pipeline with water or similar liquid, gradually increasing the pressure of the liquid to a predetermined maximum, and examining the line and/or test records for indications of a leak.

[9] The 1992 assessment was updated in 1994, 1995, and 1998.

[10] One pipeline *pressure cycle* is the pressure variation from a minimum to a maximum pressure and to the minimum again.

[11] A *joint* is a single length of pipe, nominally 40 feet long.

[12] Using the internal design strength formula in 49 CFR Part 195, a test pressure of 954 psig is calculated at 100 percent of specified minimum yield strength for line pipe with the specification of the pipe that ruptured.

noted that both defects at the point of failure showed evidence of having grown during the 1991–1992 pressure tests and concluded that ductile tearing of the metal caused the growth of these existing defects. Another Enbridge conclusion was that the operating histories of the upstream operating stations showed that pressure cycles also contributed to the failures.

After Enbridge ran tests with the Elastic Wave inspection tool, the results were reviewed and recommendations were included in Enbridge's 1995 integrity assessment report. As a result of the recommendations, Enbridge proposed to RSPA an in-line crack inspection program as the most appropriate means of reducing or eliminating the risk of pipeline failures. The detection level specification for the Elastic Wave tool stated that the tool would find a defect equal to or greater than 2.5 inches long with an accuracy of ±0.4 inch at 4.5 mph. The detection level specification for crack depth was 25 percent of the pipe wall thickness with a sizing accuracy of ±25 percent of the wall thickness. For an indication to be reported to the operator as a defect, both the crack length and the crack depth threshold requirements had to be met.

RSPA agreed in 1995 to the use of the in-line crack inspection program in lieu of hydrostatic pressure testing. As a condition for accepting the proposal for 1996, RSPA stipulated that it would review the inspection program before deciding on future pressure testing. One of the reasons for conditional approval in RSPA's stipulations was that RSPA wanted to know whether the Elastic Wave inspection tool would identify not only pipe crack defects that would fail during hydrostatic pressure testing but also considerably smaller defects that could then be repaired or removed before they could grow and lead to failure of the pipe.

In 1995, Enbridge began inspecting its 34-inch pipeline with the Elastic Wave in-line inspection tool and found that the tool was identifying more pipe crack defects than had been identified by previous hydrostatic pressure testing. Twice during 1995 and again in early 1996, PII's tool was used to inspect the pipeline section that contained the crack that ruptured in this accident, but various mechanical problems with the inspection tool resulted in unusable data. PII acquired usable data in a May 1996 inspection. (The details of this inspection are discussed later in this report.)

In the 4 years from 1995 through 1998, 216 miles (66 percent) of the 325 miles of 34-inch pipe from Gretna, Manitoba, to Superior, Wisconsin, had been inspected with the Elastic Wave tool, and pipeline repairs were made according to the pipeline operator's policy. All crack defects identified by the inspections were repaired with pipe sleeves, and none were removed and subjected to metallurgical examination. During this period of time, in-line inspections were performed on all U.S. Steel manufactured DSAW pipe. As a result of these inspections, the operator excavated the pipe at 74 locations. An evaluation concluded that none of the defects found with the Elastic Wave tool would have failed a pressure test to 100 percent specified minimum yield strength. Following completion of the Elastic Wave tool inspections in the 34-inch U.S. Steel pipe, Enbridge submitted an assessment report dated April 28, 1998, that proposed reinspecting the pipeline approximately 10 years from the previous inspection. A number of reviews were made by RSPA before closure of the consent order on May 5, 1999. After the consent order was closed, Enbridge operated the pipeline up to the pressures allowed by 49 CFR Part 195.

Before the accident, Enbridge's unwritten defect inspection practice for Elastic Wave data was to excavate all crack-like indications that were found by the Elastic Wave tool. Enbridge ran Elastic Wave tool inspections in all of its 34-inch pipeline sections in the United States between 1995 and 2001. Based on the results of these inspections, the company excavated 23 crack-like features; 23 weld/manufacturing defects; 16 other defects, including corrosion and laminations; and 41 spurious[13] indications and made repairs where needed.

### *Elastic Wave In-Line Inspection at Rupture Location*

The in-line inspection company, PII, performed a computer analysis of the May 1996 Elastic Wave inspection tool log data as part of its interpretation process after the tool was run. An indication was present at the point where the pipe ruptured on July 4, 2002. PII interpreters reviewed the indication in their initial screening of the data in 1996, but the indication did not exhibit the diamond-shaped signature signifying a crack and did not meet PII's standard that an anomaly must meet at least 6 of 10 feature selection criteria in order to be identified as a crack. After the accident, PII stated that, at most, the indication would have met two of the feature selection criteria. An important feature selection criterion that the indication did not meet was confirmation of the signal from both the clockwise and counterclockwise views as the tool records data while moving downstream through the pipe. PII representatives stated that during the May 1996 inspection run, one of the tool's two sets of wheel sensors was close to the longitudinal weld, which placed the weld in proximity to the source of the tool's ultrasonic signal and could have resulted in the masking of the signal.

PII's postaccident review of the May 1996 data also evaluated the size of the indication at the rupture and determined that it was below the detection level specification for a reportable defect (25 percent of pipe wall thickness and 2.5 inches long). The data on this indication have been recorded in a database, and PII and Enbridge have worked to determine how this information will be used to improve the feature selection criteria. Also after the accident, RSPA had an independent consultant and PII analyze the May 1996 inspection log data for the area from 0.5 mile upstream to 0.5 mile downstream of the rupture location. No indications were found with characteristics similar to those of the July 4, 2002, rupture.

In addition, PII personnel reviewed the log data from two 1995 Elastic Wave tool inspections that had shown no significant defect at the point of the 2002 rupture. They found that on the first run, the clockwise sensor was functioning properly and was not on the longitudinal weld at the point that ruptured. The counterclockwise channel was working but was electronically noisy and provided a weak signal at the point that ruptured. Thus the signal on this run did not meet feature selection criteria for confirmation of the signal from both the clockwise and counterclockwise views. The signal on this run also did not exhibit the diamond-shaped crack signature. On the second 1995 log, the clockwise channel was not providing acceptable quality data when it was in the area of the point of rupture.

[13] *Spurious* features were those that did not have a corresponding defect associated with them, had qualities not considered a defect (for example, weld profile), or were under sleeves and could not be assessed.

All of the 1995–1996 in-line Elastic Wave tool inspections were performed by the Mark II version of the device. In 1997 the tool was upgraded to the Interim Mark III, which contains an additional set of wheel sensors that are offset so at least one set of sensors is not riding on the longitudinal seam weld.

Both before and after the accident, Enbridge provided PII with feedback on its findings from actual excavations and field inspections. This feedback is a part of the continuing development effort on Elastic Wave technology. PII advised the Safety Board that it always requests feedback from its customers on field excavation data to improve accuracy and reliability. However, the amount and quality of feedback for in-line inspection tools varies with each pipeline company.

### *Pipe Movement*

On February 5, 2002, Enbridge detected movement in the 34-inch pipeline in the same marsh where the subsequent July 4 failure occurred. The movement occurred as Enbridge was excavating a ditch for the construction of a parallel 36-inch-diameter pipeline. At this point, the existing and new lines were separated by about 20 feet. As the ditch for the new line was being opened, the peat began to settle down toward the ditch, and the existing 34-inch pipeline began to move laterally toward the ditch. Enbridge workers saw the movement of the line and had the pipeline shut down for evaluation.

The pipeline was found to have moved down and laterally a maximum of 18 inches. The maximum movement had occurred at MP 1002.8 and involved more than 750 feet of pipeline. Enbridge stated that it had calculated the stresses in the pipe caused by the movement and found them to be well within the parameters for movement of an in-service pipeline as specified in API recommended practice RP 1117, *Movement of In-Service Pipelines*. Enbridge continued to monitor the site after the construction of the parallel pipeline and observed that the 34-inch pipeline had returned to within 6 inches of its original position. The return toward the original position was believed to have been caused by the rehydration of the peat.

## Railroad Transportation of Thin-Walled Pipe

A 1962 technical paper[14] prepared from research by Battelle Memorial Institute discusses the prevention of pipe stresses that can occur during the transportation, handling, and laying of thin-walled pipe. As noted in the paper, advances in technology and the availability of higher strength materials have led to the widespread use of thinner walled, larger diameter pipe that is more susceptible than thicker walled, smaller diameter pipe to stresses that could be introduced during transportation. The paper states:

[14] Atterbury, A. T., “Stresses During Shipping, Handling and Laying Thin Walled Pipe,” *Pipe Line News*, December 1962, pp. 44–47.

> Damage to line pipe during shipment has been confined to a very small number of pipe shipped. This damage has mostly taken the form of local abrasions and dents caused by contact with rivet heads or other protrusions in the rail car or truck. In a few instances, however, leaks have been attributed to fatigue cracks initiated due to cyclic stresses that are induced during shipment. It is possible for these cracks to initiate with no noticeable surface damage to identify them.

The paper goes on to say:

> The stresses developed during shipment (usually most severe during rail shipments because of higher stacks and higher g-loadings) depend on the diameter, thickness, loading configuration, and number of bearing strips. The potential damage done, of course, depends on the number of cycles of stress which are imposed during shipment.

In January 1965, the API addressed the prevention of fatigue cracks initiating during railroad transportation of pipe by publishing a recommended practice, API RP 5L1, *Railroad Transportation of Line Pipe*. API RP 5L1, which applied to 24-inch- to 42-inch-diameter pipe, included recommendations on the design of bearing strips, banding, separator strips, and longitudinal weld placement during pipe loading. The weld was to be placed at the point of least stress during loading, approximately 45° from the vertical (clock positions 1:30, 4:30, 7:30, or 10:30) and not in contact with adjacent pipes. Subsequently, API's April 1972 revision of RP 5L1 expanded the applicability of the recommended practice to include a range of diameters, 2 3/8 inches and larger, and specified that it applied to pipe having a D/t ratio of 70:1 and larger.

The hazardous liquids pipeline safety regulations in 49 CFR Part 195 do not contain requirements that address railroad transportation or any transportation of pipe. The natural gas pipeline safety regulation contained in 49 CFR 192.65, "Transportation of Pipe," which became effective on November 12, 1970, states:

> In a pipeline to be operated at a hoop stress of 20 percent or more of the specified minimum yield strength, no operator may use pipe having an outside diameter-to-wall thickness ratio of 70 to one, or more, that is transported by railroad unless the transportation was performed in accordance with API RP 5L1.

When the natural gas pipeline safety regulations became effective, pipeline operators were prohibited from using an estimated $13 million of stockpiled pipe because operators were unable to verify that the pipe, which had been transported by railroad, was transported in accordance with API RP 5L1. On February 14, 1973, RSPA amended section 192.65 of the natural gas pipeline safety regulations with paragraph (b) of the regulation, which allowed pipe meeting the above criteria that was transported before November 12, 1970, to be installed in pipelines if the pipe was pressure tested to certain requirements detailed in the section.

Colonial Pipeline Company also has experienced ruptures in its 32- and 36-inch liquid pipelines that its metallurgical report attributed to fatigue cracking in U.S. Steel manufactured pipe. Two Colonial 36-inch (D/t ratio 128:1) pipeline fatigue crack ruptures in U.S. Steel pipe transported by railroad occurred in Greenville County near Spartanburg, South Carolina, on May 13, 1979, and June 16, 1979. The May rupture released 136,000 gallons of fuel oil that damaged vegetation and killed fish. The June rupture released 395,000 gallons of fuel oil that damaged vegetation and killed wildlife and fish.

In 1980, the Safety Board investigated an accident involving a 32-inch-diameter U.S. Steel pipe (D/t ratio 114:1) in a Colonial Pipeline Company pipeline near Manassas, Virginia, in which 92,000 gallons of fuel oil leaked from a fatigue crack that was initiated during rail shipment of the pipe.[15] The rupture damaged vegetation and killed approximately 5,000 fish and some waterfowl and small animals. At the time, hydrostatic pressure testing was the only method available for finding crack defects; however, the accident report noted that hydrostatic pressure testing is inadequate because the test itself may cause small cracks to propagate without causing them to fail during the test.

As a result of its investigations of the 1980 accident, the Safety Board issued Safety Recommendations P-81-13 and P-81-14 to RSPA:

P-81-13

Expedite, in cooperation with the American Petroleum Institute and the American Gas Association, the jointly sponsored program to determine the extent of pipe failures in existing pipeline systems with a diameter-to-thickness ratio of 70 or greater due to fatigue cracks initiated during the rail shipment of the pipe.

P-81-14

If it is determined that pipe failures in existing pipeline systems with a diameter-to-thickness ratio of 70 or greater due to fatigue cracks initiated during the rail shipment of the pipe are a continuing problem, develop operating and testing guidelines to assist pipeline operators in minimizing pipe failures.

RSPA responded that the Materials Transportation Board had reviewed the extent and seriousness of a series of pipeline failures due to fatigue cracking that developed during rail transportation. As a result of the review, seven failures were found that were attributable to fatigue cracking due to railroad transportation. RSPA responded that it considered this a limited problem that did not require regulatory action at that time but that the agency would continue to monitor failures for any indications of future problems. Safety Recommendation P-81-13 was classified "Closed–Acceptable Action" on February 23, 1982. Safety Recommendation P-81-14 was classified "Closed–No Longer Applicable" on March 21, 1983.

[15] National Transportation Safety Board, *Colonial Pipeline Company Petroleum Products Pipeline Failures, Manassas and Locust Grove, Virginia, March 6, 1980*, Pipeline Accident Report NTSB/PAR-81/2 (Washington, DC: NTSB, 1981).

On December 18, 1989, another fatigue crack failure occurred on Colonial's 32-inch pipeline in U.S. Steel pipe. As a result of the 1989 failure, RSPA's Office of Pipeline Safety created a task force to study Colonial pipeline failures attributable to fatigue cracking. U.S. Steel, Kaiser Steel, A.O. Smith, Bethlehem Steel, and Republic Steel manufactured the pipe involved in the study, and the pipelines were constructed between 1962 and 1964. Of these manufacturers' pipes, all had a submerged arc weld in the longitudinal seam except the A.O. Smith pipe, which had a flash-welded longitudinal welded seam. The RSPA task force concluded in its September 14, 1990, report that six Colonial pipeline failures from 1970 through 1989 resulted from fatigue cracking that was probably initiated during rail transportation of the pipe. The task force report stated that five fatigue crack failures were found in U.S. Steel pipe and that one was found in Republic Steel pipe. The report stated that crack growth by fatigue is a greater possibility in liquid lines than in gas lines because liquid lines are subjected to frequent and substantial cycles of pressure variations during normal operations.

The RSPA task force report describes the loading method tests that Battelle Laboratories conducted in 1962 under contract from Colonial Pipeline Company. Battelle reported that the susceptibility to fatigue cracking during rail transportation increases for pipe with larger D/t ratios because such pipe is more susceptible both to static stresses from the weight of the pipe and to cyclic stresses during transportation. RSPA's report also noted that the American Gas Association conducted research to develop solutions to transportation fatigue and found that the higher the D/t ratios, the more susceptible the pipe to fatigue crack initiation. The American Gas Association research concluded that pipe with a D/t ratio greater than 70:1 has a possibility of fatigue crack initiation and requires special care in railcar loading. RSPA's 1990 task force report stated that with the implementation of API RP 5L1 in 1965, the occurrence of railroad transportation cracks had been virtually eliminated.

A 1988 paper[16] documented numerous transit fatigue crack failures that occurred during initial hydrostatic pressure testing of the pipe. The types of pipe included DSAW, electric resistance weld, and seamless steel pipe that had been shipped by rail or marine vessels. In nine fatigue failures that occurred between 1969 and 1982, the pipe had been transported by railroad and the diameters ranged from nominal 6-inch to 20-inch pipe with D/t ratios from 42:1 to 64:1. In 17 fatigue failures that occurred between 1976 and 1987, the pipe had been transported by marine vessel and ranged from 6 inches to 24 inches in diameter with D/t ratios from 28:1 to 85:1. The paper stated:

> Transit fatigue results from cyclic stresses induced by gravitational and inertial forces. The weight of a load of pipe imposes a steady stress of a given magnitude. As the load moves up and down, the pipe flexes, inducing alternating tension and compression at both the inside and outside surfaces. The alternating stresses initiate cracks.

[16] Bruno, T.V., "Transit Fatigue of Tubular Goods," *Pipe Line Industry*, July 1988, pp. 31–34. (This paper is also referenced in the foreword of the sixth edition of API RP 5L1, July 2002.)

The D/t ratios that could lead to fatigue cracking during transportation were changed in the 1990 edition of API RP 5L1. The ratio was reduced from 70:1 to 50:1 because fatigue cracking had been reported in pipe with D/t ratios lower than 70:1. The latest edition of API RP 5L1, issued in July 2002, also states that pipe with D/t ratios well below 50:1 may suffer fatigue in transit under some circumstances.

No statistics on transportation damage were specifically tracked before RSPA instituted a change in 2002 to gather more detailed accident statistics. However, RSPA is now gathering information on whether an accident is caused by pipe damage sustained during transportation and whether the failure is a longitudinal tear or crack.

## Railroad Transportation of Accident Pipe

The section of pipeline where the rupture occurred was constructed in 1967. The Enbridge 1966 purchase specification for the pipe included a requirement that pipe loading details be provided subject to its approval. In its quotation, U.S. Steel provided a diagram for railroad car loading (see figure 9), which Enbridge subsequently approved. The railcar loading instructions consisted of a drawing with notes specifying the blocking supports and banding to be used under and around the pipe and the required positioning of the longitudinal weld. U.S. Steel also noted in its specifications that the purchaser would spot-check railcar loadings at the mill before transportation. U.S. Steel transported the pipe by railcar to its storage facility near the mill, where it was unloaded and stored. Later, U.S. Steel loaded the pipe for transportation by rail. Finally, the pipe was loaded on trucks for transportation to the construction sites.[17] Enbridge had arranged with Moody Engineering Company (Moody) to inspect the manufacturing of the pipe. The handling and loading of the pipe for transportation from the mill to storage was a part of that inspection. These activities were summarized in Moody's final report. The Moody report indicates that the pipe was periodically inspected at a nearby storage facility to ensure that the pipe was being handled and unloaded with care. The report indicates that the pipe was accepted for shipment subject to the operator's shipping instructions. U.S. Steel did not document inspections of pipe loading. No records were found to indicate that the engineering company or the pipeline operator inspected the loading of the pipe on railroad cars for transportation from the U.S. Steel storage facility.

[17] Records related to the production activities at U.S. Steel's McKeesport pipe mill were destroyed several years ago after the mill was closed for a period of time.

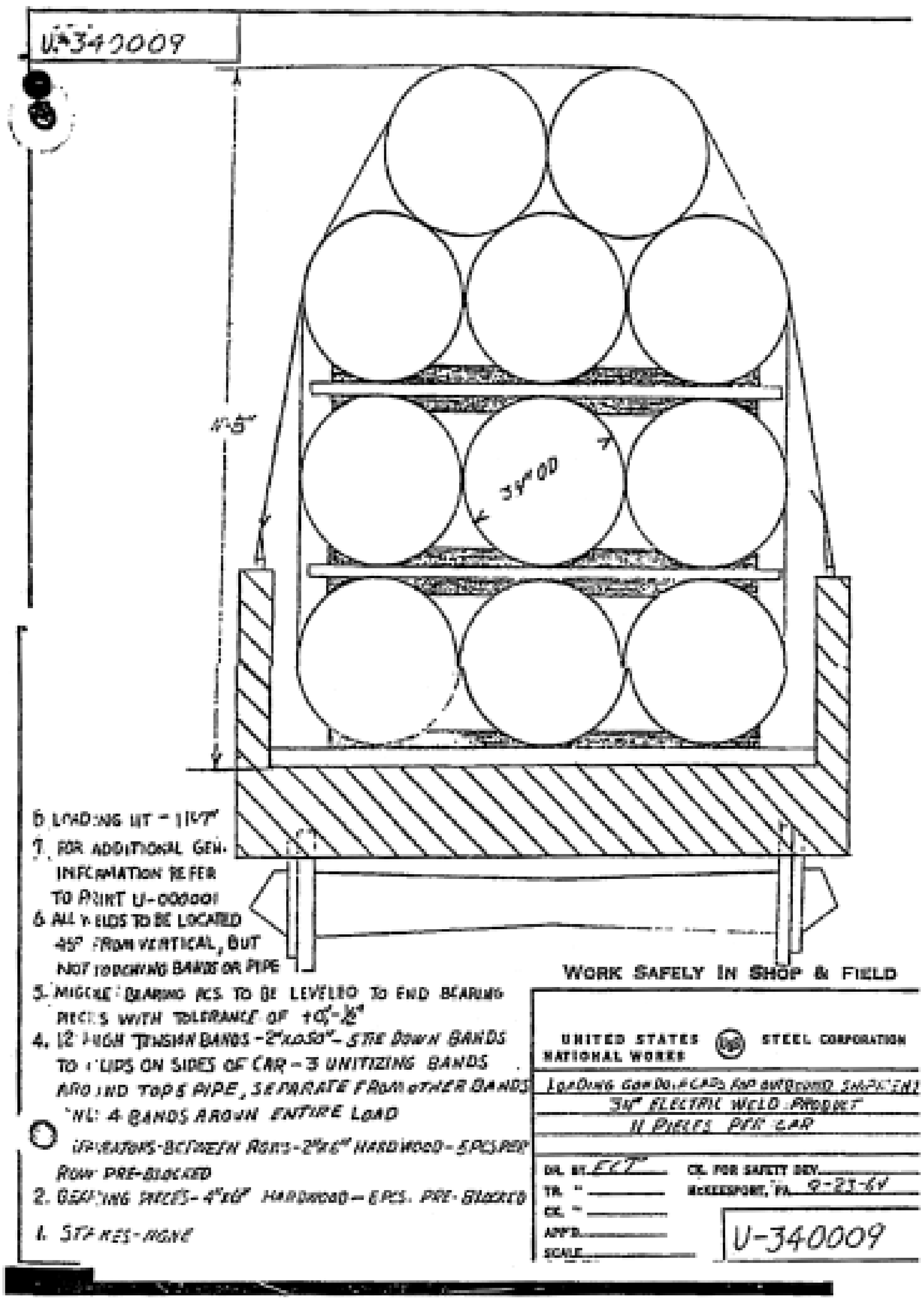


**Figure 9.** U.S. Steel loading diagram for railcars.

The U.S. Steel employees who had loaded the 1966 DSAW pipe order could no longer be found. According to a former shipping department employee (who was not present at the time of the Enbridge pipe loading), a typical pipe loading practice before and after this pipe order was to position the longitudinal weld at the 2, 4, 8, or 10 o'clock position so the pipe weld would not touch lumber, bands, or other pipe. If a 40-foot joint of pipe was not loaded in this position, it was to be rotated as necessary to attain one of these positions. Except for the loading diagram, there were no written procedures for loading pipe, nor did U.S. Steel use checklists or other methods to confirm that the pipe was loaded according to specifications.

U.S. Steel does not currently manufacture DSAW or SAW pipe. U.S. Steel Tubular Products does produce seamless and electric resistance weld pipe, and the current loading procedures for the pipe are described in the company's *Pack, Mark, and Load Manual*. The procedures to be used for each order are entered into the order entry system from the purchase order and are designated on the mill order sent to the production mill. All pipe manufactured to API standards and destined for railroad transportation from the pipe mill is to be loaded to the requirements of the Association of American Railroads' *Open Top Loading Rules Manual*[18] and the supplementary recommended practices in API RP 5L1. Any additional transportation requirements are referenced in the mill order for the shipping department personnel and, if applicable, are attached to the mill order. A preproduction meeting is held at the mill to review the order and shipment requirements.

At pipe mills currently producing tubular products for U.S. Steel, shipping department workers are trained in the department's standard operating procedures. The group leader in the loading area discusses the loading requirements for each order with the crew. A load tally sheet is created that shows the length of each pipe joint with the referenced heat number for the material. The yard foreman checks the railcars periodically to confirm that the pipe is loaded according to the written requirements.

Before 1991, Enbridge specified that the manner of loading pipe for rail transportation should be provided in the pipe manufacturer's quotation, which was subject to Enbridge's approval. Currently Enbridge includes the use of API RP 5L1 in its specification for purchase of pipe transported by rail from a pipe mill. Enbridge also inspects the pipe during loading at the pipe mill to confirm that the requirements of API RP 5L1 are being met.

## Safety Board Materials Laboratory Study

The Safety Board performed a finite element study of the U.S. Steel loading practice to determine the static stresses in pipe loaded for rail transportation. The study showed that the peak circumferential tensile stresses would have been highly localized to the areas in contact with the bearing and separator strips and that the stresses would have occurred at the inner surface of the pipe.

The length of the fatigue crack in this accident was similar to the length over which the peak circumferential tensile stress was predicted in the finite element model, and the fatigue crack initiated at the inner surface of the pipe. The finite element model

[18] The Association of American Railroads' *Open Top Loading Rules Manual* includes Section 1, General Rules Manual for Loading all Commodities, and Section 2, Loading Metal Products Including Pipe.

indicated that the circumferential tensile stresses decreased rapidly away from the bearing or separator strips. Aligning the welded seams at 45° to the vertical results in very small levels of circumferential tensile stress at the welds during transport. (See figure 10.) The results of the finite element model also indicate that aligning the welds at the 2, 4, 8, or 10 o'clock positions instead of exactly 45° from vertical does not increase the stress levels significantly.

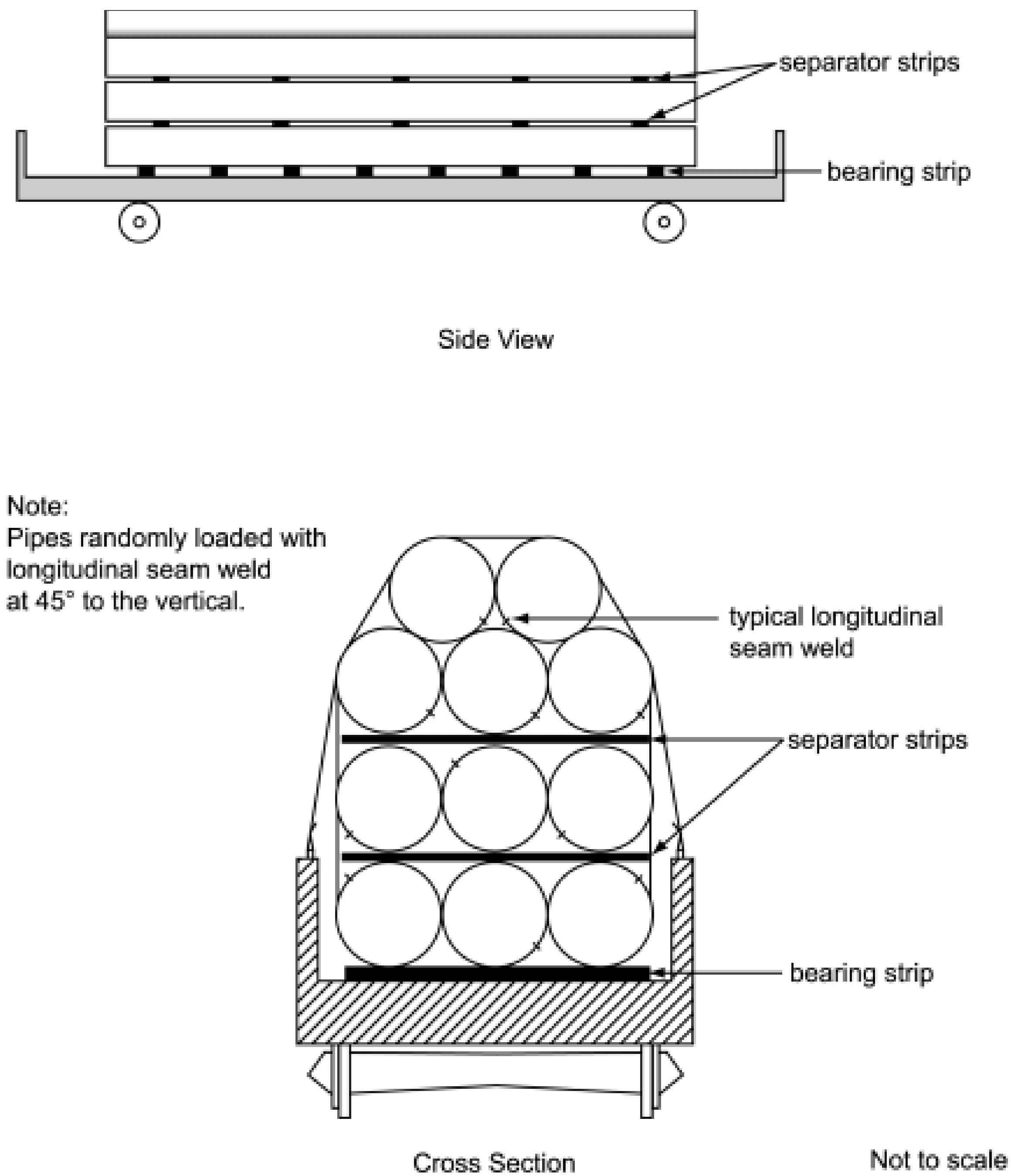


**Figure 10.** Typical pipe configuration on railroad car.

The Safety Board also studied API loading practices for rail transportation to determine the static stresses in pipe loaded for transportation. API RP 5L1 provides an equation for calculating the peak circumferential tensile stress in a pipe at a bearing strip as a function of the geometry of the loading. API RP 5L1 does not indicate the source of the equation. The purpose of this equation is to calculate the number of flat bearing strips needed to keep the stress below a specified level. The stress determined from the finite element model was compared to the stress calculated by the equation from API RP 5L1 under the same conditions. For a 40-foot-long, 34-inch-diameter, 0.300-inch-wall thickness pipe, the comparison indicates that the equation from API RP 5L1 underestimates the peak circumferential tensile stress by a factor of approximately 2.

The API has also published guidelines for loading pipe for transport onboard marine vessels, API RP 5LW, *Recommended Practice for Transportation of Line Pipe on Barges and Marine Vessels*. API RP 5LW also includes an equation for calculating the peak circumferential tensile stress in a stack of pipe supported by bearing strips. However, this equation differs significantly from the API RP 5L1 equation, and no source is given for the equation. The stress determined from the finite element model was also compared to the stress calculated by the equation from API RP 5LW under the same conditions. For a 40-foot-long, 34-inch-diameter, 0.300-inch-wall thickness pipe, the comparison indicates that the equation from API RP 5LW also underestimates the peak circumferential tensile stress by a factor of approximately 2.

The Safety Board also evaluated the pipe movement attributed to the nearby excavation on February 5, 2002. The pipeline moved down and laterally a maximum of 18 inches. The deflection of the pipe led primarily to longitudinal tension and compression stresses that would not have affected the fatigue crack (oriented on a plane radially outward along the welded seam). Circumferential tensile stresses and shear stresses associated with the pipe deflection were calculated to be in the range of 1 to 10 psi in comparison to the circumferential tensile stress of 29,750 psi caused by the internal pressure of the oil in the pipe at the time of the rupture.

## RSPA Postaccident Corrective Action Order

On July 5, 2002, RSPA issued to Enbridge a corrective action order that required the pipeline operator to conduct a detailed metallurgical analysis of the July 4 failure to determine the cause and contributing factors. The corrective action order also prohibited Enbridge from operating the pipeline until it had submitted a return-to-service plan, which was to incorporate a program to verify the integrity of the 34-inch pipeline from the Deer River Pump Station to Superior Terminal. The plan was to include, if relevant, an in-line inspection survey using a technologically appropriate tool capable of assessing the type of failure that had occurred, including the detection of longitudinal cracks, and remedial action. If relevant, the return-to-service plan was to include an evaluation of the pipeline coating system, a hydrostatic pressure test of the line segment, and a review of all available pipeline data and records.

Enbridge submitted its return-to-service plan to RSPA on July 8, 2002. On July 9, RSPA allowed the pipeline to be restarted with pressure restrictions.

On July 11, RSPA amended the corrective action order to include an operating pressure restriction on pipeline segments between the U.S./Canadian border and Superior Terminal that contained any U.S. Steel pipe. The amended order required that pump station pressure discharges be no higher than 80 percent of the pressure in the line at the time of rupture and that line pressure at the failure site not exceed 80 percent of the pressure at the time of rupture.

On December 2, RSPA permitted Enbridge to raise pressures at pump stations on the Gretna to Clearbrook section of pipe from 80 percent of discharge pressures at the time of the July 4 accident to 80 percent of the highest discharge pressure reached within 30 days of the accident. On June 5, 2003, RSPA allowed the operation of Viking Station, which did not have pump units installed on the 34-inch line at the time of the accident.

## Enbridge Postaccident Actions

Before the accident, the area where the pipeline ruptured was not designated a high-consequence area. According to the 2000 census, the population in the area had increased enough to make it a high-consequence area. Enbridge's data on the crude oil released in this area were also used in the 2002 evaluation of Enbridge's high-consequence area pipeline segment identification program. The amount of crude oil released did not trigger the addition of the Cohasset segment as a high-consequence area. In May 2003, as a result of the population change only, the pipeline segment containing the rupture site was classified as a high-consequence area.

Enbridge had begun using a more technologically advanced in-line crack inspection tool, the UltraScan CD, in Canada in 1997. The company ran the tool for the first time in the 34-inch line in the United States in 2001. The detection level specification for the tool states that it will find a defect equal to or greater than 2.50 inches long with an accuracy of ±0.2 inch at 4.5 mph. The detection level specification for crack depth is 0.040 inch with accuracy of ±0.040 inch. Both the crack length and crack depth thresholds must be met for the indication to be reported to the operator as a defect. Since the accident, Enbridge has developed and documented a methodology for determining the need for an investigative excavation from the data obtained from an UltraScan CD. Enbridge also has prepared a pipeline inspection procedure, "Excavation Program for Crack Feature Assessment," as guidance for personnel performing field excavations based on data from the UltraScan CD. The new policy calls for the excavation of all crack-like indications unless an engineering assessment determines that either the indication is acceptable based on a fitness-for-purpose calculation or the indication is not a crack.

Enbridge had reviewed its in-line inspection program and updated it to run the UltraScan CD tool from Gretna, Manitoba, Canada, to Clearbrook, Minnesota, in 2001 and from Clearbrook to Deer River in 2003. The UltraScan CD tool inspected the pipeline section from Gretna to Clearbrook in July 2001, about 1 year before the accident. The data interpretation was completed in September 2002, about 2 months after the accident. No new crack-like indications[19] were reported in the longitudinal seam weld of this pipeline section by the in-line inspection. One notch-like feature[20] identified in a segment of U.S. Steel pipe was excavated and found to be in the middle of a weld cap. Enbridge determined that the feature was an external weld shrinkage crack that was not likely to be related to transportation fatigue. A second notch-like feature was classified as a low-priority feature to be excavated in the future. Other indications were inspected, and no longitudinal cracks were found in any of the field inspections.

Enbridge representatives told the Safety Board that, in addition to excavating all crack-like indications reported by the UltraScan CD tool, the company currently excavates for field examination all notch-like indications in U.S. Steel pipe that are reported at the longitudinal weld to determine whether they are cracks. Currently, the UltraScan CD in-line inspection report does not include a depth estimate for notch-like indications. PII is working with Enbridge to develop a depth estimate of notch-like indications for future inspections. The UltraScan CD inspection tool was run from Clearbrook, Minnesota, to Superior, Wisconsin, in November 2002, and in February 2003 the analysis of the indications found in U.S. Steel pipe was completed. Interim reports allowed for an earlier start of the excavation program for the highest priority indications. The UltraScan CD tool reported 285 defect indications in 121 pipe joints that Enbridge excavated, inspected, and assessed by nondestructive test methods.

Included in these defect indications were 6 crack-like and 29 notch-like indications that were either adjacent to or in the longitudinal weld on U.S. Steel pipe. Enbridge has excavated the 6 crack-like indications and 4 of the 29 notch-like indications to visually inspect and examine the pipe by nondestructive means. The field examination of five of the crack-like indications showed that three were stress corrosion cracking,[21] and two were at the toe of the longitudinal weld. The sixth crack-like indication was found to be a sharp weld contour. One notch-like indication was a defect that was found to have a 42-percent-depth wall thickness crack. Two notch-like indications were an internal gouge and a weld profile (a higher than normal weld cap) feature. The final notch-like indication that was examined was a low-priority feature that was found to be an external shrinkage crack in the center of a weld. The remaining 25 notch-like indications near or in the longitudinal weld were classified as low priority. Enbridge plans to excavate these notch-like indications. Stress corrosion cracking was also found by the UltraScan CD tool and reported as crack-field[22] indications.

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[19] In PII terminology, a *crack-like indication* is one that is interpreted from UltraScan inspection data as a crack, which is typically at or in the longitudinal weld.

[20] *Notch-like* defects are grooves in the toe of the DSAW longitudinal seam weld, manufacturing defects in flash-welded or electric resistance welded longitudinal seam welds, weld trimming tool marks adjacent to the longitudinal seam weld, or handling marks made during transportation or construction. Although not interpreted to be crack-like features, depending on their characteristics, these indications may need to be considered for excavation because field inspection may reveal them to be cracks.

[21] *Stress corrosion cracking* is the formation of cracks, typically in a colony or cluster, as a result of the interaction of tensile stress, a corrosive environment, and a susceptible material. A colony of very short, axially aligned cracks seen in the field is the typical result of such cracking.

[22] In PII terminology, *crack-field* refers to a crack interpreted as stress corrosion cracking.

The UltraScan CD tool found all internal cracks, now under pipe sleeve repairs, that were previously found by the Elastic Wave tool. No new internal crack-like indications were reported by the UltraScan CD tool under the sleeves, nor were any found during nondestructive field examination of the pipe.

During the field excavations, Enbridge found 21 additional external weld toe cracks on U.S. Steel pipe that were not reported by the inspection tool. According to the field examinations, all 21 of the cracks were below the detection limit specification of the tool. The field information gathered from the entire excavation program will help PII evaluate defect parameters. Of the 285 indications, approximately 60 reported by the tool had field-verified features that were below the contracted threshold limit of the tool for depth, length, or both.

The UltraScan CD tool was designed to detect even smaller defects with a higher degree of reliability than the Elastic Wave tool. Enbridge had an analysis performed that established ranges of key input parameters for predicting reinspection intervals. Using the knowledge learned from the July 2002 failure, Enbridge had crack growth rates for a variety of defect sizes. The most conservative (worst-case) scenario evaluated was a defect 0.080 inch deep by 7.5 inches long, two times the depth and three times the detection threshold of the UltraScan CD tool. This defect has a predicted time until failure of approximately 6.5 years. Enbridge has proposed to RSPA that an alternative to hydrostatic pressure testing is reinspecting the Clearbrook to Superior section of the 34-inch pipeline within 3 years of the previous in-line crack tool inspection.

Enbridge currently has a program to evaluate and repair stress corrosion cracking when it is found in the pipeline. Enbridge has provided field feedback to PII on the UltraScan CD tool data gathered from Gretna to Superior on stress corrosion cracking in the pipe. Enbridge also has asked PII to recalibrate the UltraScan CD tool data using Enbridge's field information to improve the accuracy of stress corrosion crack depth estimates. In addition, a metal loss in-line inspection was completed from the U.S./Canadian border to Superior, Wisconsin.

As a result of these in-line inspections, Enbridge has stated that repairs have been made according to company procedures to all defects that were excavated and examined.

## American Society of Mechanical Engineers Pipeline Codes

American Society of Mechanical Engineers (ASME) code B31.8, 2003 edition, *Gas Transmission and Distribution Piping Systems*, section 816, contains guidance on transporting pipe in accordance with the API railroad or marine vessel recommended practices:[23]

[23] API RP 5L5, *Transportation of Line Pipe on Barges and Marine Vessels*, was created in 1975 and later was designated API RP 5LW.

> Any pipe having an outer-diameter-to-wall thickness ratio of 70 to 1 or more, that is to be used in a pipeline at a hoop stress of 20 percent or more of the specified minimum yield strength that has been or will be transported by railroad, inland waterway, or by marine transportation, must have been or shall be loaded in accordance with API RP 5L1 or API RP 5LW, respectively. When it is not possible to establish that pipe was transported in accordance with the appropriate practice, the pipe must be hydrostatically tested for at least 2 hours to at least 1.25 times the maximum allowable pressure if installed in a Class 1 location, or at least 1.5 times the maximum allowable pressure if installed in a Class 2, 3, or 4 location.

ASME B31.4, 1998 edition, *Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids*, section 434.4, states: "When applicable, railroad transportation of pipe shall meet the requirements of API RP 5L1."

# Analysis

A metallurgical examination of the failed pipe segment of Enbridge's 34-inch-diameter crude oil pipeline indicated that the rupture had occurred at a fatigue crack along a longitudinal seam weld. Hydrostatic pressure testing and an in-line inspection tool specifically designed to find cracks did not detect the crack before failure.

In its investigation of this accident, the Safety Board attempted to determine how and when the initial fatigue crack occurred and to assess methods used to detect cracking in older pipelines before it propagates to pipe failure. The investigation identified the following safety issues:

- The effectiveness and application of line pipe transportation standards.
- The adequacy of Federal requirements for pipeline integrity management programs.

## The Accident

The Enbridge Control Center SCADA system's first indication of a release on line no. 4 was dropping suction and discharge pressures at the Deer River station at 2:12 a.m. on July 4, 2002. Subsequently, the Floodwood station suction pressures began dropping, and the controller realized that he had an abnormal condition and suspected a leak. At 2:13 a.m., the pipeline controller called for the shift coordinator, and at 2:14 a.m., about 2 minutes after the rupture, they decided to shut the line down. Within 3 minutes of this decision, all pumps were shut off, and the valves had begun to close. About 4 minutes later, the final closure of remotely controlled valves at Deer River and the remotely controlled valve at MP 1017.9 isolated the ruptured section from the remainder of the pipeline.

About 2:25 a.m., the Deer River and Floodwood police departments were notified of the suspected leak, and at 2:30 a.m. the responsible Enbridge regional personnel were notified. The control center then began analyzing the SCADA data to locate the leak and estimate the volume of the release. The Safety Board concludes that Enbridge's pipeline control center personnel responded in a timely manner to the indications of a pipeline leak.

## Transportation of Accident Pipe

At the time Enbridge purchased the pipe that ruptured in this accident, the pipeline industry was aware that thin-wall, large-diameter pipe (such as the 109:1 D/t ratio pipe that ruptured in this accident) was particularly susceptible to cyclic stresses encountered during transportation, especially by rail, and that such stresses could lead to the initiation of fatigue cracking in the pipe unless the pipe was properly loaded and transported. Welded areas were also known to be the areas most susceptible to fatigue crack initiation during transportation.

To address concerns about pipe stress during transportation, Enbridge had required in its purchase specification that pipe loading details be provided subject to its approval. U.S. Steel submitted a diagram with specifications for rail car loading that was designed to protect the pipe, and Enbridge approved it. Enbridge retained an engineering company to inspect the manufacturing, handling, and loading of the pipe by U.S. Steel at the mill and the subsequent unloading at its storage site near the mill. The engineering firm's final report indicated that the pipe was accepted at the storage site for shipment subject to Enbridge's instructions. Final transportation of the pipe was done later from storage, with the pipe traveling by both rail and truck.

The U.S. Steel loading diagram for the railroad shipment that included the accident pipe provided for leveling bearing strips and placing separator strips for support of the pipe, orienting longitudinal welds at 45° to the vertical, and avoiding contact with adjacent pipes. The U.S. Steel diagram was similar to the loading specifications for railroad transportation of line pipe in the January 1965 edition of API RP 5L1. As noted previously, this recommended practice addressed loading pipe to minimize stresses across the longitudinal welded seams of pipe, which are susceptible to fatigue cracking. The Safety Board's review determined that the provisions in the U.S. Steel loading diagram for rail transportation satisfied the requirements of the January 1965 edition of API RP 5L1.

The metallurgical testing and examination of the fatigue crack and ruptured area of the accident pipe found no material or manufacturing defect in the steel or in the welded longitudinal seam. In the absence of manufacturing or material defects, the creation of a fatigue crack would be unlikely to result from normal operational pressure cycles. However, once a fatigue crack has been created it may grow with the repetitive stresses from normal operational pressure cycles.

The fracture surfaces of the fatigue crack in the accident pipe had multiple arrest lines and other indications of progressive cracking starting from the inside surface of the pipe wall. There were two regions paralleling the inside surface; the region next to the pipe wall was darkened and oxidized and contained multiple crack initiation sites. The adjacent region where the crack extended further into the pipe wall was lighter and cleaner, exhibiting little or no oxidation. The oxidation found in the darkened region most likely occurred while the faces of the fatigue crack were exposed to the atmosphere before the pipe was placed in service. The lighter region indicates that the fatigue crack grew while oil was protecting the crack surfaces from oxidation.

The Safety Board's finite element analysis revealed that the length of the fatigue crack was consistent with the high stress region predicted on the inside surface of the pipe at a bearing or separator strip. Documents show that Enbridge used an engineering company for the specific purpose of inspecting the U.S. Steel pipe until it was stored near the mill. Further, the pipe was transported only a few miles before storage, whereas it was transported about 1,000 miles by rail and truck from storage to construction sites in Minnesota, suggesting a greater likelihood that the pipe was damaged after it was removed from storage. Further, there is no documentation to substantiate that instructions for loading pipe on railroad cars were followed after storage, and no evidence was found to indicate whether pipe loading instructions existed for transportation by truck. Therefore, the stress levels necessary for the initiation and initial growth of the fatigue crack were most likely caused by cyclic forces acting on the pipe during transportation after storage. The finite element analysis for the accident pipe shipment showed that following the rail loading standard, which prescribes size and placement of bearing/separator strips and alignment of the welded seams at 45° to the vertical, would not have resulted in stress levels high enough to initiate fatigue cracking during transportation. Therefore, the Safety Board concludes that, after storage, the accident pipe was likely inadequately loaded for transportation, which led to the initiation of fatigue cracking along a longitudinal seam weld before the pipe was placed in service. The Safety Board further concludes that after installation the preexisting fatigue crack grew with pressure cycle stresses until the crack reached a critical size and the pipe ruptured.

## Transportation Fatigue Cracking in Line Pipe

A number of fatigue cracks similar to the one in the Enbridge pipe have led to failures in DSAW (double submerged arc weld) pipe at other locations. Improper positioning of welds when loading pipe joints can create stress in the longitudinal weld during rail transportation that is sufficient to initiate fatigue cracks that are consistent with the type of damage observed in the Enbridge and Colonial pipeline DSAW pipe. As shown in the 1988 metallurgical study of pipe referenced in the current API RP 5L1, fatigue cracks occurring in pipe having various seam types led to 26 pipe failures during initial hydrostatic testing between 1969 and 1987. All of these failures occurred after the pipe had been transported by rail or marine mode.

When compared to the Safety Board's finite element analysis of the static stress developed in the area of a bearing or separator strip (see figure 10) in a stack of 34-inch-diameter, 0.300-inch-wall thickness pipe, the equation in API RP 5L1 for calculating static load stresses underestimated the stresses in the pipe by a factor of approximately 2. However, the Safety Board's analysis indicates that the effectiveness of API RP 5L1 in preventing fatigue crack initiation can be explained by the emphasis on leveling the bearing strips and on the proper alignment of welded seams at 45° to the vertical, leading to a significant reduction in stress at the welds, which are the areas most susceptible to the initiation of fatigue cracking. Although implementation of the recommended practice has resulted in a reduction of railroad transportation fatigue crack initiation, the Safety Board concludes that API RP 5L1, *Recommended Practice for Railroad Transportation of Line Pipe,* may significantly underestimate the stresses in the pipe at the bearing or separator strips. In the case of the accident pipe shipment, regardless of whether the stress levels were underestimated in the rail loading standard, as noted previously, following the rail loading standard would not have resulted in stress levels high enough to initiate fatigue cracking.

API RP 5LW, *Recommended Practice for Transportation of Line Pipe on Barges and Marine Vessels*, also provides an equation for calculating the static load stress in a stack of pipe for shipment, but this equation is significantly different from the equation in API RP 5L1. When the Safety Board compared the stresses calculated using the equation in API RP

5LW to those determined by the finite element analysis for 34-inch-diameter, 0.300-inch-wall thickness pipe, it found that the equation in API RP 5LW also underestimates the stresses in pipe loaded for transport by a factor of approximately 2. The Safety Board, therefore, concludes that API RP 5LW may significantly underestimate the stresses in the pipe at the bearing or separator strips. The Safety Board believes that the API should review the equations in API RP 5L1 and API RP 5LW for calculating the static load stresses at the bearing or separator strips and revise the recommended practices based on that review.

## Natural Gas Pipeline Safety Regulations

To prevent the formation of fatigue cracks during railroad transportation of pipe that is to be used in natural gas service, 49 CFR Part 192.65 (effective November 12, 1970) required shippers to follow the requirements of API RP 5L1 when transporting pipe for which the expected hoop stress during service was equal to or greater than 20 percent of the specified minimum yield strength. When the regulation became effective, pipeline operators were prohibited from using an estimated $13 million of stockpiled pipe that had been transported by rail because operators were unable to verify that the pipe had been transported in accordance with API RP 5L1. RSPA granted an exemption in February 1973 that allowed the installation of this pipe if it were pressure tested to higher pressures than normally required. However, transportation fatigue cracks can grow to failure in service after the pipeline has been pressure tested. Therefore, the Safety Board concludes that hydrostatic pressure testing of a pipeline is insufficient to expose all transportation fatigue cracks that may eventually cause pipe failure. Although the amount of pipe still in stock that was transported before November 12, 1970, without documentation that API RP 5L1 was followed is likely not significant, such pipe could be placed in service. Therefore, the Safety Board believes that RSPA should remove the exemption in 49 CFR 192.65 (b) that permits pipe to be placed in natural gas service after pressure testing when the pipe cannot be verified to have been transported in accordance with API RP 5L1.

## Liquid Pipeline Safety Regulations

The RSPA task force report noted that crack growth from fatigue in pipelines is a greater possibility in liquid lines than in gas lines because liquid lines are subject to frequent and substantial pressure cycle variations during normal operations. In contrast to the regulations for transport of natural gas pipe, no similar Federal requirements are applicable to hazardous liquid pipe to ensure that such pipe is protected from fatigue crack initiation during railroad transportation. In a letter to the Safety Board dated July 21, 2003, RSPA indicated that it intends to revise 49 CFR Part 195 for hazardous liquid pipelines to require the use of API RP 5L1, consistent with Part 192 for pipe transportation for gas pipelines. The Safety Board encourages RSPA to promptly amend 49 CFR Part 195 to require that hazardous liquid pipeline operators follow API RP 5L1 for railroad transportation of pipe.

## Marine Transportation of Pipe

Pipe shipped by marine transportation has also exhibited transportation-related failures, but the pipeline safety regulations have no requirement that a standard be followed when pipe is transported on a marine vessel. The API recommended practice for transportation of pipe on marine vessels, API RP 5LW, was first issued in 1975 as API RP 5L5. In addition to 9 fatigue failures attributed to rail transportation in the 1988 metallurgical study, 17 fatigue failures were attributed to pipe transported by ship that failed during hydrostatic testing between 1976 and 1987 while the recommended practice was available to the pipeline industry. The Safety Board concludes that there is a potential risk of pipe damage due to fatigue crack initiation during marine vessel transportation of pipe, similar to the risk during rail transportation, for both hazardous liquid and natural gas pipelines. Therefore, the Safety Board believes that RSPA should amend 49 CFR to require that natural gas pipeline operators (Part 192) and hazardous liquid pipeline operators (Part 195) follow API RP 5LW for transportation of pipe on marine vessels.

## Truck Transportation of Pipe

Rail transportation has generally been considered to be the most likely source of transit fatigue cracking because of the larger number of pipe rows and high loads, long distances, and long travel times involved. A number of previous pipeline failures have been attributed to rail transportation fatigue, but the pipe also was transported in the field by truck following rail transit. Since no information was available regarding truck loading and transport conditions for the pipe that ruptured, the possibility of fatigue crack initiation during truck transportation cannot be ruled out.

It is reasonable to assume that pipe, in addition to incurring abrasions or dents, could incur fatigue damage during truck transportation. A pipeline industry standard does not exist for the loading requirements for transportation of steel pipe on trucks. Although the Safety Board does not have any data with which to determine the extent of fatigue crack initiation that may occur as a result of highway transportation induced stresses, the Safety Board concludes that the absence of industry loading standards for truck transportation of pipe might create risks to the integrity of both natural gas and hazardous liquid pipelines. The Safety Board, therefore, believes that RSPA should evaluate the need for a truck transportation standard to prevent damage to pipe, and, if needed, RSPA should develop the standard and incorporate it in 49 CFR Parts 192 and 195 for both natural gas and hazardous liquid line pipe.

## ASME Pipeline Codes

As noted previously, ASME B31.8, *Gas Transmission and Distribution Piping Systems*, section 816, contains an exemption that allows the installation of pipe that may not have been loaded and transported in accordance with the appropriate API railroad or marine recommended practice with no restriction on when the transportation took place. The exemption allows a hydrostatic pressure test in lieu of compliance with the API recommended practices. The exemption requires a hydrostatic pressure test for a minimum of 2 hours at higher than normally required test pressures. Even though the Federal pipeline safety regulations take precedence in cases of a conflict or apparent conflict with any industry guidance, the Safety Board is concerned that the ASME B31.8 piping code may lead pipeline operators to erroneously believe that pressure testing exposes all fatigue cracks initiated during transportation and verifies the integrity of pipe that may not have been loaded and transported in accordance with API standards. Therefore, the Safety Board believes that ASME should amend ASME B31.8, *Gas Transmission and Distribution Piping Systems*, section 816, to remove the provision that pressure testing may be used to verify the integrity of pipe that may not have been transported in accordance with the API recommended practices for transportation of pipe by railroad or marine vessels.

ASME B31.4, *Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids*, section 434.4, requires that the transportation of pipe by railroad follow API RP 5L1 but does not require that marine transportation of pipe follow API RP 5LW. The Safety Board believes that ASME should amend ASME B31.4, *Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids*, section 434.4, to require the use of API RP 5LW for marine transport of pipe.

## Pipeline Integrity Management

Hydrostatic pressure testing was performed on Enbridge's pipeline after construction in the 1960s and at various times through the 1980s. As a result of a 1991 fatigue crack rupture, RSPA required Enbridge to develop an operational reliability assessment that included additional pressure tests and to make changes to pipeline operations that included lowering pressure cycle stress in order to improve pipeline integrity. A number of defects failed during the 1991–1992 hydrostatic pressure testing, including some fatigue cracks. By 1995, RSPA had approved Enbridge's use of an in-line inspection tool, the Elastic Wave tool, to find pipe cracks, rather than hydrostatic pressure testing. By using this tool, Enbridge found a number of cracks that the company repaired before failure. By 1998, the interval for in-line crack tool reinspection had been established as 10 years from the previous inspection. The pipeline section that failed in this accident had last been inspected in May 1996 with an in-line crack-detection tool, which was run approximately 6 years before the rupture.

In the May 1996 inspection, an indication was present at the point where the pipe later ruptured on July 4, 2002, but the indication did not exhibit the diamond-shaped signature typical of a crack and did not meet the inspection company's interpretation standard of at least 6 of 10 feature selection criteria to identify it as a crack. After the accident, the inspection company's analysis confirmed that the indication did not meet the feature selection criteria. RSPA's postaccident review concurred with this analysis. The Safety Board concludes that the Elastic Wave in-line inspection conducted before the accident recorded an indication at the point where the pipe eventually failed; however, preaccident and postaccident interpretations of the recorded data found that the indication did not meet the feature selection criteria to identify it as a crack. Relatively large cracks can be found when a pipe fails during hydrostatic pressure testing; however, the potential also exists for smaller cracks to grow but not fail during a pressure test and then continue to grow due to normal operational pressure cycle stress. In its report of the 1980 accident in Manassas, Virginia, the Safety Board noted that it is unlikely that all fatigue cracks will be found during hydrostatic pressure testing. To expose fatigue cracks on the 34-inch pipeline in 1991, Enbridge used hydrostatic pressure testing. However, smaller fatigue cracks that remained in the pipe continued to grow to the point of failure before the next pressure test. Within 2 1/2 years of an Enbridge pressure test, two fatigue cracks failed, resulting in crude oil leaks. The Enbridge metallurgical evaluation indicated that the stress developed during hydrostatic testing was sufficient to propagate the cracks but insufficient to cause an immediate failure. Beginning in 1995, Enbridge inspected its entire 34-inch pipeline in the United States using the Elastic Wave in-line inspection tool. Enbridge's policy was to excavate all reported crack defects for evaluation whether or not the affected pipeline segment was in a high-consequence area.

After this accident, RSPA reviewed the data from the 1995–1996 Mark II Elastic Wave inspection tool for the failed joint of pipe. That review confirmed that the inspection log data showed an indication in the pipeline at the point of rupture; however, the data did not meet the crack identification criteria established by the inspection company. As a result of this accident, RSPA informed the Safety Board on July 21, 2003, that it plans to issue an advisory bulletin to all pipeline operators about reevaluating previous Mark II Elastic Wave tool inspections used to detect crack-like defects near the longitudinal weld and taking remedial action necessary to ensure the continued integrity of the pipeline. In addition, according to RSPA, pipeline operators will be issued a directive to monitor pressure cycles to verify that assumptions made in the original remaining life analyses for cracks remain valid and to ensure that input parameters are within the tool tolerance range and detection level when analytical methods are used to establish retesting intervals. Furthermore, RSPA will modify the forms it uses to guide comprehensive integrity management audits to ensure that pipeline operators adhere to the requirements of the advisory bulletin. The Safety Board supports the completion of these actions that can be taken now by pipeline operators to improve pipeline integrity.

RSPA, with the financial assistance of industry trade associations, is also conducting research leading to the development of a quantitative basis for evaluating the significance of pipe material and construction features having time-, environment-, and cycle-dependent growth mechanisms (which includes fatigue cracking) that threaten pipeline integrity in natural gas transmission pipelines. In addition to evaluating the significance of defects in pipe seams, the study will assess defects in pipe manufacturing, pipeline construction, pipe base metal, girth welds, and fabrication welds to quantify conditions under which otherwise benign material and construction features can become active and grow to failure. The research will examine the threats to natural gas pipeline integrity including external and internal corrosion, stress corrosion cracking, and fatigue cracks. The research is intended to identify the conditions that cause the defects to grow and will not be limited to operating pressure or hydrostatic pressure testing. An evaluation technique will also be created for pipeline operators to develop effective mitigation criteria for their pipelines. The Safety Board agrees that, in addition to fatigue cracking, other types of time-, environment-, and cycle-dependent defects need to be considered when evaluating threats to hazardous liquid pipeline integrity. If RSPA is satisfied with the results of the natural gas research, the study could be extended to include hazardous liquid pipelines, and the Board encourages RSPA to proceed with the hazardous liquid pipeline research to better evaluate pipeline integrity.

In the past, Enbridge had modified the expected crack growth rate from pressure cycle stress based on knowledge gained from investigating prior failures that occurred on the 34-inch-diameter pipeline system. However, in 2001 Enbridge started using the UltraScan CD, a more technically advanced in-line crack inspection tool, for in-line inspections of its 34-inch line in the United States. Since the accident, Enbridge has studied crack growth due to pressure cycle stress using its current crack growth rate model. The company based the study on various sizes of potential fatigue cracks that the UltraScan CD tool was specified to find. For this study, Enbridge assumed that cracks of various sizes would not be found by the inspection tool, then performed an analysis, with the reduced pipeline pressure cycles Enbridge intends to achieve, to project how long those cracks would continue to grow until they might fail. The largest potential crack evaluated in the study was one that was two times the depth and three times the length of the threshold size of a crack that the UltraScan CD tool could detect. The analysis concluded that a crack this large would still have a predicted remaining life of 6.5 years. As a result of the crack-growth evaluation, Enbridge is now proposing to RSPA that it perform the next in-line inspection in the Clearbrook to Superior 34-inch pipeline section using the more advanced in-line crack inspection tool within 3 years of the last inspection.

On September 5, 2003, RSPA requested modifications to Enbridge's return-to-service plan, which include running the UltraScan CD tool in 2005 and analyzing crack growth rate after the reinspection. Enbridge responded that it would reinspect the line between Clearbrook and Superior in 2005 and use the resulting data to refine crack growth rates and determine future integrity requirements. Because cycle-dependent growth is a factor in fatigue crack failures, adhering to operating practices that limit the number and magnitude of pipeline pressure cycles is critical to limiting crack growth. Enbridge also has committed to monitoring and analyzing pressure cycle data on a quarterly basis and to sending each analysis to RSPA at least until the in-line crack tool inspection of the Clearbrook to Superior section is completed in 2005. The Safety Board supports efforts to monitor operating data and refine crack growth rate estimates to help determine appropriate in-line reinspection intervals.

The Federal pipeline safety regulations require that certain actions be taken when conditions are found that could affect pipeline safety. Enbridge's policy regarding fatigue cracks has been and still is to run an in-line crack inspection tool in the entire 34-inch pipeline regardless of high-consequence area designation. Before RSPA's integrity management rule, Enbridge analyzed the crack failure data and established a reinspection time interval for its 34-inch pipeline based on an engineering evaluation of the crack growth rate. Now, RSPA's integrity management rule for high-consequence areas, 49 CFR 195.452 (e), requires that a hazardous liquid operator consider all risk factors to establish an assessment schedule, including the "results of a previous assessment, the defect type and size that the defect assessment method can detect, and the defect growth rate."

# Conclusions

## Findings

1. Enbridge’s pipeline control center personnel responded in a timely manner to the indications of a pipeline leak.

2. After storage, the accident pipe was likely inadequately loaded for transportation, which led to the initiation of fatigue cracking along a longitudinal seam weld before the pipe was placed in service.

3. After installation the preexisting fatigue crack grew with pressure cycle stresses until the crack reached a critical size and the pipe ruptured.

4. The American Petroleum Institute recommended practice 5L1, *Recommended Practice for Railroad Transportation of Line Pipe,* and American Petroleum Institute recommended practice 5LW, *Recommended Practice for Transportation of Line Pipe on Barges and Marine Vessels,* may significantly underestimate the stresses in the pipe at the bearing or separator strips.

5. Hydrostatic pressure testing of a pipeline is insufficient to expose all transportation fatigue cracks that may eventually cause pipe failure.

6. There is a potential risk of pipe damage due to fatigue crack initiation during marine vessel transportation of pipe, similar to the risk during rail transportation, for both hazardous liquid and natural gas pipelines.

7. The absence of industry loading standards for truck transportation of pipe might create risks to the integrity of both natural gas and hazardous liquid pipelines.

8. The Elastic Wave in-line inspection conducted before the accident recorded an indication at the point where the pipe eventually failed; however, preaccident and postaccident interpretations of the recorded data found that the indication did not meet the feature selection criteria to identify it as a crack.

## Probable Cause

The National Transportation Safety Board determines that the probable cause of the July 4, 2002, pipeline rupture near Cohasset, Minnesota, was inadequate loading of the pipe for transportation that allowed a fatigue crack to initiate along the seam of the longitudinal weld during transit. After the pipe was installed, the fatigue crack grew with pressure cycle stresses until the crack reached a critical size and the pipe ruptured.

# Recommendations

As a result of its investigation of the July 4, 2002, pipeline rupture near Cohasset, Minnesota, the National Transportation Safety Board makes the following safety recommendations:

### To the Research and Special Programs Administration:

Remove the exemption in 49 *Code of Federal Regulations* 192.65 (b) that permits pipe to be placed in natural gas service after pressure testing when the pipe cannot be verified to have been transported in accordance with the American Petroleum Institute recommended practice 5L1. (P-04-01)

Amend 49 *Code of Federal Regulations* to require that natural gas pipeline operators (Part 192) and hazardous liquid pipeline operators (Part 195) follow the American Petroleum Institute recommended practice 5LW for transportation of pipe on marine vessels. (P-04-02)

Evaluate the need for a truck transportation standard to prevent damage to pipe, and, if needed, develop the standard and incorporate it in 49 *Code of Federal Regulations* Parts 192 and 195 for both natural gas and hazardous liquid line pipe. (P-04-03)

### To the American Society of Mechanical Engineers:

Amend American Society of Mechanical Engineers B31.8, *Gas Transmission and Distribution Piping Systems*, section 816, to remove the provision that pressure testing may be used to verify the integrity of pipe that may not have been transported in accordance with the American Petroleum Institute recommended practices for transportation of pipe by railroad or marine vessels. (P-04-04)

Amend American Society of Mechanical Engineers B31.4, *Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids*, section 434.4, to require the use of the American Petroleum Institute recommended practice 5LW for marine transport of pipe. (P-04-05)

### To the American Petroleum Institute:

Review the equations in American Petroleum Institute recommended practice 5L1, *Recommended Practice for Railroad Transportation of Line Pipe*, and American Petroleum Institute recommended practice 5LW, *Recommended Practice for Transportation of Line Pipe on Barges and Marine Vessels*, for calculating the static load stresses at the bearing or separator strips and revise the recommended practices based on that review. (P-04-06)

## BY THE NATIONAL TRANSPORTATION SAFETY BOARD

**MARK V. ROSENKER**
Vice Chairman

**JOHN J. GOGLIA**
Member

**CAROL J. CARMODY**
Member

**RICHARD F. HEALING**
Member

**Adopted: June 23, 2004**

**Chairman Ellen Engleman Conners** did not participate in the adoption of this report.

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# Appendix A

## Investigation

The National Transportation Safety Board was notified on July 4, 2002, through the National Response Center, of a pipeline release in an isolated, swampy area west of Cohasset, Minnesota. The Safety Board dispatched an investigative team from its Washington, D.C., headquarters. The team comprised investigative groups in pipeline operations, SCADA, and emergency response. No Board member accompanied the investigative team. No depositions or hearings were held in conjunction with the investigation. Enbridge Pipelines (Lakehead), LLC; PII North American, Inc.; United States Steel Corporation; the Minnesota Office of Pipeline Safety; Minnesota Pollution Control; the Minnesota Department of Natural Resources; the Cohasset Fire Department; and RSPA's Office of Pipeline Safety were parties to the investigation.